Global Energy Markets

Answers to the Most Frequently Asked Oil and Gas Questions

Equities

Global
Oil Companies, Major

Jon Rigby, CFA
Analyst
jon.rigby@ubs.com
+44-20-7568 4168

William A. Featherston
Analyst
william.featherston@ubs.com
+1-212-713 9701

Joseph Head
Associate Analyst
joseph.head@ubs.com
+44-20-7568 5568

Cutting our near term oil price forecast: but still well above futures strip

We've marked to market for 4Q15 and lowered our 2016 Brent/WTI oil price forecasts ($/Bbl) to $42.50/$40.00 (from $57.50/$52.50), reflecting the much weaker 4Q outturn and lower entry point into 2016. In the near-term the market remains oversupplied and we expect global inventories to continue building until 3Q16, dampening any potential price recovery. In the medium term however we view current prices as unsustainable: we believe much of the recent fall is short-term momentum driven with limited reference to longer-term fundamentals, not unusual when the market is unbalanced given the gulf between cash costs of existing supply ($30-40/bbl) and the long-run marginal cost. However, like all capital cycles, this one continues to turn: 2016 will see the full impact of the collapse in the US rig count, driving a 0.8Mb/d contraction in non-OPEC supply, while the market looks tighter from 2018 onwards as the impact of the dearth of project sanctions in 2015 is felt (1.3Mboe/d vs the norm of 5Mboe/d). As this becomes more apparent, we believe the focus will shift to the price needed to incentivise sufficient new investment to offset decline (5-8% per annum) and meet incremental demand (~1% per annum) – a figure of $70-80/bbl in our view which still implies a phenomenal reduction in unit costs from 2014 levels.

Lowering our US natural gas price forecasts

We've also lowered our 2016-19 & long-term, normalised natural gas price forecasts ($/MMBtu) to $2.45, $2.75, $3.00, & $3.25, respectively, from $3.25, $3.75, $4.00, & $4.00. We now forecast 2016 suffering from the overhang of a material storage surplus, as well as a more tempered long-term demand growth outlook coupled with the ability to meet demand growth with prices well below $4/MMBtu.

…but not your typical mark-to-market note

Beyond the revised oil price forecast in Figure 1 below, the remainder of this report provides UBS' answers to the most frequently asked questions on oil prices and our market outlook. These span a wide range of topics including: the outlook for upstream capex and the response of non-OPEC supply to prices; the nature of OPEC's role in the market; the shape of the global cost curve; demand elasticity; and natgas/LNG markets.

Figure 1: Revised UBS Oil and Natural Gas Price Forecasts (2016-20E and Normalised)

	2014A	2015A	1Q16E	2Q16E	3Q16E	4Q16E	2016E	2017E	2018E	2019E	2020E	Normalised
WTI ($/Bbl)	**$92.89**	**$48.81**	**$35.00**	**$38.00**	**$41.00**	**$46.00**	**$40.00**	**$52.00**	**$67.00**	**$72.00**	**$72.00**	**$72.00**
Previous Estimate		*$49.00*	*$50.00*	*$50.00*	*$55.00*	*$55.00*	*$52.50*	*$65.00*	*$70.00*	*$75.00*	*$75.00*	*$75.00*
First Call Consensus		**$49.79**	**$44.00**	**$46.00**	**$51.00**	**$57.00**	**$50.00**	**$60.00**	**$65.00**	**$65.00**	**NA**	**NA**
Futures Strip Price		**$49.26**	**$32.91**	**$34.70**	**$37.12**	**$38.85**	**$35.91**	**$41.77**	**$45.89**	**$49.02**	**$50.71**	**NA**
UBS vs Consensus		-2%	-20%	-17%	-20%	-19%	-20%	-13%	3%	11%	NA	NA
UBS vs Strip prices		*-1%*	*6%*	*10%*	*10%*	*18%*	*11%*	*24%*	*46%*	*47%*	*42%*	*NA*
Brent ($/Bbl)	**$99.38**	**$53.57**	**$36.00**	**$41.00**	**$44.00**	**$49.00**	**$42.50**	**$55.00**	**$70.00**	**$75.00**	**$75.00**	**$75.00**
Previous Estimate		*$55.00*	*$55.00*	*$55.00*	*$60.00*	*$60.00*	*$57.50*	*$70.00*	*$75.00*	*$80.00*	*$80.00*	*$80.00*
First Call Consensus		**$54.94**	**$50.00**	**$50.00**	**$55.00**	**$60.00**	**$53.80**	**$60.00**	**$68.75**	**$68.50**	**NA**	**NA**
Futures Strip Price		**$54.01**	**$33.52**	**$33.65**	**$36.19**	**$38.52**	**$35.48**	**$43.72**	**$46.60**	**$49.31**	**$51.43**	**NA**
UBS vs Consensus		-2%	-28%	-18%	-20%	-18%	-21%	-8%	2%	9%	NA	NA
UBS vs Strip prices		*-1%*	*7%*	*22%*	*22%*	*27%*	*20%*	*26%*	*50%*	*52%*	*46%*	*NA*
Natural Gas NYMEX ($/MMBtu)	**$4.45**	**$2.67**	**$2.30**	**$2.40**	**$2.50**	**$2.60**	**$2.45**	**$2.75**	**$3.00**	**$3.25**	**$3.25**	**$3.25**
Previous Estimate		*$2.85*	*$3.25*	*$3.25*	*$3.25*	*$3.25*	*$3.25*	*$3.75*	*$4.00*	*$4.00*	*$4.00*	*$4.00*
First Call Consensus		**$2.79**	**$2.72**	**$2.50**	**$3.00**	**$3.01**	**$2.85**	**$3.25**	**$3.50**	**$3.75**	**NA**	**NA**
Futures Strip Price		**$2.67**	**$2.38**	**$2.47**	**$2.57**	**$2.70**	**$2.53**	**$2.83**	**$2.94**	**$3.03**	**$3.15**	**NA**
UBS vs Consensus		-4%	-15%	-4%	-17%	-14%	-14%	-15%	-14%	-13%	NA	NA
UBS vs Strip prices		*0%*	*-3%*	*-3%*	*-3%*	*-4%*	*-3%*	*-3%*	*2%*	*7%*	*3%*	*NA*

Source: UBS estimates, FactSet, and Bloomberg

www.ubs.com/investmentresearch

Contents

Jon Rigby, CFA
Analyst
jon.rigby@ubs.com
+44-20-7568 4168

William A. Featherston
Analyst
william.featherston@ubs.com
+1-212-713 9701

Joseph Head
Associate Analyst
joseph.head@ubs.com
+44-20-7568 5568

Global Oil Markets

Market outlook

In the absence of any intervention by OPEC, we expect that the laws of economics will slowly correct the oil market along its pathway of readjustment. When the final data is in we expect a healthy year of demand growth for 2015 as price and wealth impacts work their way through (UBSe +1.7Mb/d, the strongest year for demand since 2010). 1Q16 will likely see a further price effect, driving FY demand growth a little above trend at +1.3Mb/d. Meanwhile the market continues to look tighter from 2016 and beyond as non-OPEC supply reflects the impact of a swathe of capex cuts – at first in the US (now showing signs of rolling over) and then longer-cycle production elsewhere. 2015 to date has seen just 3 major oil projects totalling 0.8Mb/d plateau liquids production reach FID vs the ~5Mb/d average. In the absence of a clear price anchor we believe that while the market oversupply persists crude will likely trade in a wide range between cash costs of current supply (~$35/bbl before sufficient volumes to clear the market are at risk of being shut-in) and the long-run marginal cost, with volatility exacerbated by the number of closely watched (but in our view often marginally relevant) datapoints. Reflecting the significant over-supply, OECD inventories are at record highs and we see global stocks continuing to build until 3Q16 in the absence of any material supply-side interruption. This will likely hold back price appreciation through 2016, although with spare capacity ~1.5Mb/d below historic norms we contend that higher-than-normal inventory levels are warranted. In the longer term the market needs to incentivise sufficient new supply which will require a pick-up in activity in non-US/non-OPEC where we believe the marginal barrel lies. Cost reduction and deflation continues to work its way through the upstream, and while some of this is cyclical pressure on the supply chain, there is growing evidence that operators are implementing overdue structural change which will be more persistent. These changes will not be easy however – sustaining historic rates of return at our long-term forecast of $75/bbl will require reductions of ~40% in unit development capex vs 2014 levels.

Upside scenario

Our base case scenario assumes no intervention from OPEC – we are sceptical about the group's willingness and capacity to reduce output in the absence of unanimity. We expect Saudi to wait to see its initiative play out and we don't believe the group will function as a cohesive cartel. If the group were to step in however it would likely target >$70/bbl where the fiscal breakevens lie for the key Gulf producers. Geopolitics and interruption to a medium-sized OPEC producer could add $5-10/bbl per 0.5Mb/d disruption. If physical markets begin to focus on shortage of spare capacity over high inventory levels as the market balances then 4Q16 and 2017 could see prices >$60/bbl and closer to the investment incentive level of $70/bbl earlier than we project.

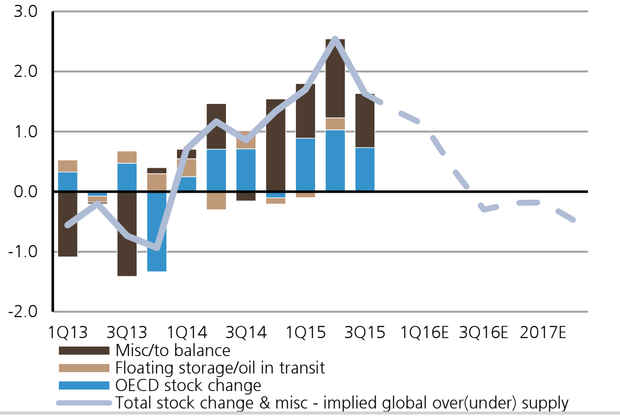
Downside scenario

We project an over-supplied market until 3Q16 implying a significant inventory build over the period. While this has a moderate pricing impact in its own right a filling of physical storage could create distressed pricing– benchmarks would likely fall below $30/bbl. Global GDP growth slipping by 100bps (cf 2014) could impact demand by ~500kb/d and defer market rebalancing by ~1 year (note there hasn't been a global recession since 2009). Chinese GDP growth at 4% in 2016 not 6.2% as UBS forecasts would have a limited first-order impact (130-150kb/d) but the second-order global GDP effects (0.3-0.4Mb/d) would likely depress prices by $10-15/bbl while the slowdown persisted. Iran returning more quickly than we forecast (we project a gradual return to current capacity of ~3.6Mb/d over 2016 then a slow build-out to ~4Mb/d through to 2020) would prolong oversupply into 2017.

Upcoming catalysts

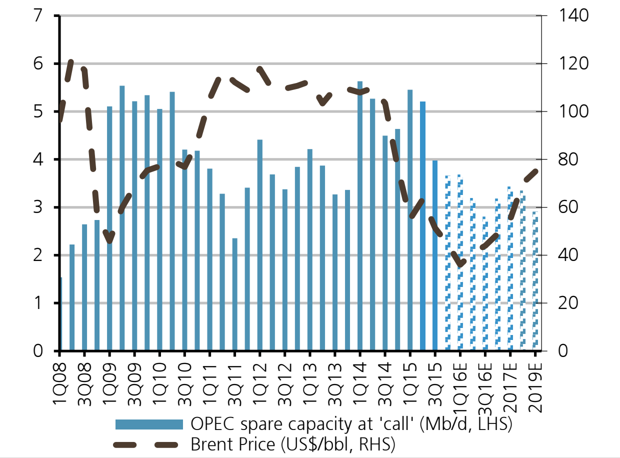
1H16?	US L48 y/y production decline accelerates
Early 2016?	Potential lifting of Iranian nuclear sanctions
2015-16	Continued slowdown in project FID activity

UBSe S/D balance and implied stock change (Mb/d)



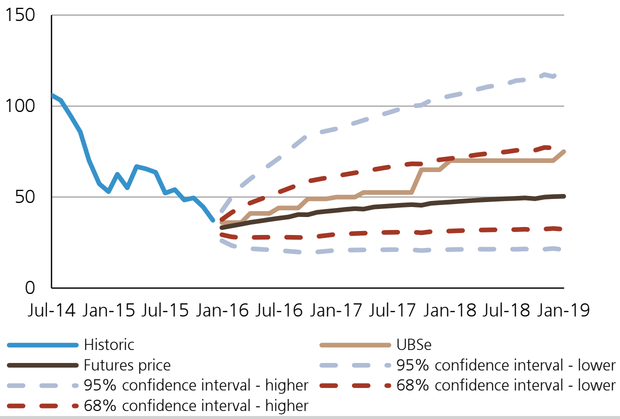
Source: UBS, IEA. Note: forecast stock change assumes OPEC holds output flat at 31.7Mb/d

OPEC spare capacity (at 'call') vs Brent price



Source: UBS, IEA, DataStream.

Brent ($/bbl), UBSe, futures strip and options market-implied confidence intervals



Source: UBS, Bloomberg. Strip as of 11 January 2016

Global Energy Markets – Answers to the most frequently asked oil and gas questions

In this note we are updating our upstream crude oil and natural gas price forecasts. As we did at this time last year we have departed from our normal report structure to address what we consider the key questions surrounding the pricing environment for the upstream industry at the outset of a new year. 2015 was a dramatic year for the energy market and we have no reason to believe that 2016 will be any less important. Indeed, the first week of 2016 appears to confirm this.

2014/15 a classic capital cycle: downturn driven by too-high level of upstream investment, multiplied by the actions of OPEC. Strong demand and a depressed level of project sanctions is beginning to correct this.

In terms of the crude oil market our basic position can be summarised in saying that at its core we see a classical capital cycle playing out. High levels of upstream investment were facilitated by too-high oil prices and cheap money. The effect of this build-up of productive capacity was multiplied by the actions of OPEC, which as a group was unable to agree to withdraw production volume from the market – indeed member countries increased production from already existing 'spare' capacity. Against the historic structure of the oil market this represents a meaningful change. The effect of this excess in production has been to severely cut into prices. As we speak Brent and WTI are around 70% down from their mid 2014 peaks. Much of the recent fall, we believe, is short-term momentum driven with limited reference to medium/long-term fundamentals but is not an unusual feature of the market when it tips out of balance (to the upside as well as the downside). However, like all capital cycles, this one is clearly continuing to turn. 2015 saw significantly better than trend demand and a clear depressing effect on investment levels which is beginning to show up on the supply-side. The key question is how does this cycle fully play out and what is the nature of the market when the adjustment has taken place? Of course, it is also important to recognise that this cycle and indeed the market that emerges from it will additionally be distinguished by the emergence of US tight oil production and some of the unusual characteristics this particular activity brings with it.

Near-term prices cut to acknowledge low starting point: but we expect a recovery into end-2016 and 2017 as the market moves into balance.

We believe that 2016 will be another year in the market's adjustment. This means that 2016 prices may actually average lower than 2015, but they should exit the year strengthening as the market begins to reach balance, with further upside risk moving into 2017. Although the physical shape of the year, and indeed the evolution of supply/demand is materially unchanged from our previous forecasts, our price forecast has been cut to acknowledge the lower starting point than we had previously envisaged (emphasised by lower 4Q15 average outturn than forecast). We acknowledge that this implies quite rapid appreciation at some stage in 2016/17 but one characteristic of this market has been material price adjustments over very short periods of time. We have previously commented that while the market is in over-supply (albeit only 2-3%) then there are limited price 'anchors' and the trading range is likely very wide and highly sensitive to prevailing sentiment. That sentiment has been bad, in particular focussing on the build-up in inventories and concerns around the outlook for the Chinese market, hence the very low prices currently. Market participants remain concerned about the current over-supply, the incipient return of higher Iranian exports and the limits of global physical storage, and while this continues prices will remain low. Moreover, the signing of the Iran deal, the December OPEC meeting, and the decision by the Fed in December to raise rates, were all expected but still had a negative impact on prices so we should not assume that developments in 2016 even if widely

expected are 'in the price'. The high upfront capital investment and relatively low cash costs of production (even before accounting for the shut-in decision) means that oil prices can remain well below the levels required to incentivise new investment for quite some time. Inflection points are always difficult to identify but we believe that prices have reached or are likely to reach their nadir in the next 3-6 months. Within that time frame we believe that it will be evident to all that a balanced market is in prospect and that there is unlikely to be a 'tank-tops' pricing situation. At this point the focus should shift to the price needed to incentivise new investment (which has collapsed): enough to offset declines and meet incremental demand growth. This figure is complicated by the new phenomenon of tight oil and the moving target that is industry costs but we believe that this figure lies between $70-$80/bbl – which for the record implies a phenomenal reduction in unit costs from the levels recorded by the industry in 2014. Of course, in all probability, even with the shorter cycle characteristics of US production, the adjustment process is also at risk of overshooting on the upside, but that is a discussion for another day.

Lower levels of global spare capacity provide less flexibility to absorb a shock – we believe a higher level of inventories is warranted as a result.

At this juncture it's also worth reflecting on a market where the influence of OPEC is reduced. A key stabilising influence in the market has been the presence of the producer group and in particular its facility to raise and lower production. The decision by Saudi Arabia and the Gulf states in 2014 not to cut production and support prices and then to raise production, thus reducing global spare capacity creates meaningful risk in the medium/long term because the capacity to adjust to a demand or supply shock is reduced. Without the dampening effect of spare production capacity, all equal the market will become more volatile even with higher inventories and 'short cycle' tight oil resources. That is why we believe that prices can start to rise even without inventories materially falling. If we are wrong the currently high level of inventories will continue to weigh on prices until they are worked off.

Evolution of 2016-18+ Oil Price Forecast

At this time last year, the WTI/Brent 2015 futures curves were $56/$61 per bbl and in steep contango and the 2016 futures strips were $62/$68/bbl. And while the average 2015 price turned out to be $8/Bbl lower than the implied price at the beginning of the year, the current 2016 futures strip of ~$37.50 for both WTI and Brent is roughly 45% lower than it was one year ago. We highlight this to demonstrate that the futures curve is not always right. In fact our study of the futures strip over the last 15 years indicates average prices end up being 29% different on average than the forward curve implies at the beginning of the year. With that backdrop, we highlight below why we believe the forward curve is too low and the factors that account for our higher price forecast relative to the futures strip, particularly as one goes further out on the curve.

- **We forecast 2016 WTI/Brent of $40/$42.50/bbl, modestly above the futures strip as we acknowledge the current oversupply and several uncertainties that will depress oil prices near-term.** With record high inventories of >2,900 Mbbls, the first half of 2016 is confronted with the challenging combination of further builds in inventories (UBSe 0.7 Mb/d), the potential lifting of Iranian sanctions which could lead to increased volumes into an already oversupplied market, and slowing global growth exacerbated by an increasingly uncertain outlook for China. But we would argue that oil is pricing in much of this bad news with prices now below cash costs in several key producing regions (North Sea, Canadian heavy oil, and US stripper wells). Based

on Wood Mackenzie analysis dated January 2015, 1.5 MB/d of global supply is cash negative at $40/bbl, 3.5 Mb/d at $35/bbl, and 5.5 Mb/d at $30/bbl. Importantly, we expect a modest draw in global inventories to begin in 3Q marking an inflection point for a turnaround in the path for oil prices.

- **Our 2017 WTI/Brent forecast of $52/$55/bbl is roughly 20% above the futures strip as we expect oil prices to be firmly on a path to recovery next year.** In 2017, we see a modest decline in inventories (although this is sensitive to assumptions around Iranian output) coupled with low spare capacity of 3.4 Mb/d (at the 'call'), down from 5.0 Mb/d in 2014 and 4.6 Mb/d in 2015. And given that 2016 should be a second consecutive year of abnormally low project sanctions of mega-projects needed to offset global depletion, we believe prices will advance in 2017 in order to provide the signal to non-OPEC producers that increased activity will be needed to meet demand growth in 2018-19 to fill the void that will be created in 2018+ from the absence of project sanctions in 2015-16.

- **Our 2018+ WTI/Brent forecasts are >40% above the current futures strip, highlighting our increased conviction in higher prices the further one goes out on the curve.** In a growing global economy, we do not see how a sub-$50/bbl forecast works for the major producing constituencies: 1) the US (source of over 80% of non-OPEC production growth from 2009-14) needs over $60/Bbl to drive sustained production growth; 2) most Majors need at least $60/Bbl to just cover capex and the dividend; and 3) even after sharp spending cuts, we estimate Saudi Arabia could need ~$80/Bbl to balance its budget. Moreover, we estimate 2015 large project sanctions of just 1.3 Mboe/d and 2016 to again be an unusually low year, well below the typical 5.0-5.5 Mboe/d average in our database. The absence of these barrels coupled with low spare capacity will quickly tighten the market leading to sharply higher prices in order to re-store balance.

How does the physical market drive the futures price?

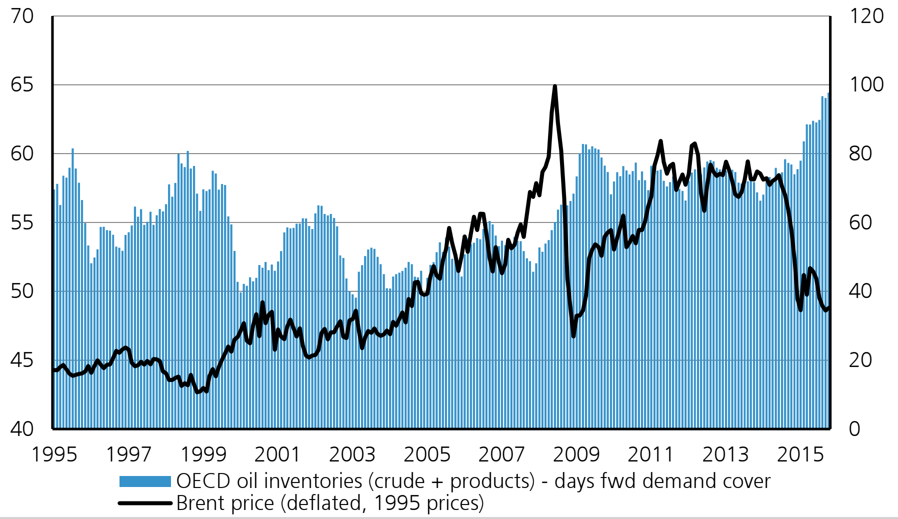
There are a number of aspects of the physical market that interplay with crude prices, and historically these have waxed and waned in their relative importance. In the long term we believe that crude prices are set by reference to full-cycle marginal costs: crude supply declines at 5-8% per annum on an unmitigated basis while demand grows at ~1%, thus the long-term clearing price needs to incentivise sufficient investment. Hence we believe that analysis of the global cost curve (see page 15 for our discussion of this) is essential to understand the drivers of normalised crude prices.

In the medium term however deviations from this level are affected by supply/demand dynamics and the market's adjustment process: inventory levels, rates of change of supply/demand and OPEC spare capacity have historically all had an influence on pricing.

Inventory levels act as a lagging indicator of supply/demand imbalances, and hence are closely related with pricing – furthermore high inventory levels provide a buffer vs unexpected supply shocks (the converse is also true). In forward demand terms end-October OECD inventories stood at 64.3 days, close to an all-time high, a product of OPEC's decision to produce from its spare capacity rather than leaving crude in the ground. We expect inventories to continue building through 1H16, implying continuing pricing pressure until the market moves into balance from

3Q16 and we tenatatively predict drawdowns begin – although the margins are fine and any number of small variations from our forecasts could push the balancing point back into 2017 (a faster Iranian return than we project, continued resilience in US supply, a weaker than projected 1H16 for demand growth).

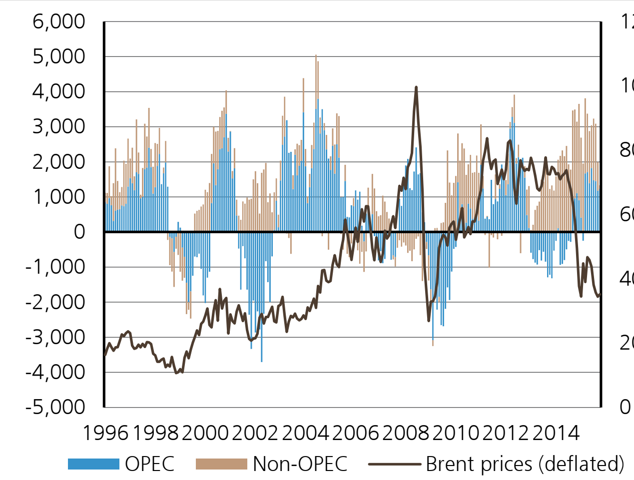
Figure 2: OECD oil inventories (demand cover, LHS) vs real Brent price (RHS)



Source: IEA, UBS, DataStream

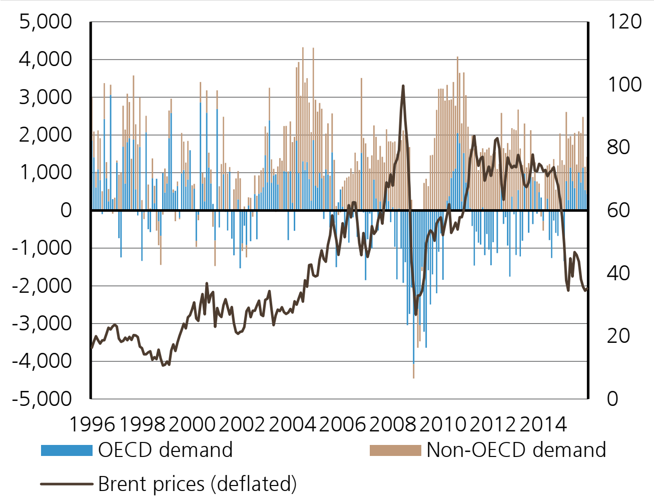
Rates of change of supply and demand are also closely watched and have acted as short-term price triggers historically. In the present cycle the focus is on US supply - in particular when it rolls over into y/y declines – whereas in previous demand-led collapses (e.g. 2008/09) the more closely watched datapoints have tended to be around demand. On the supply side we expect that non-OPEC supply began to roll over into negative y/y territory in November 2015 (the latest actual datapoints, for October 2015, indicate that y/y growth had slipped to ~100kb/d from 2.3Mb/d in January 2015). We expect y/y non-OPEC declines to peak at above 1.1Mb/d in 2Q/3Q16, driven by the US, and anticipate that as the official data begins to indicate this crude pricing could stabilise and begin to recover.

Figure 3: Global oil y/y supply growth (monthly, LHS, kb/d) vs real Brent price (RHS)



Source: IEA, UBS, DataStream

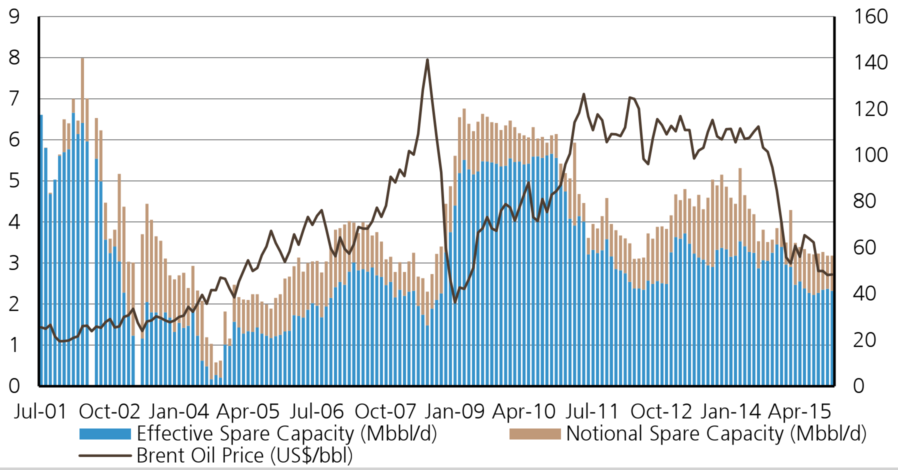
Figure 4: Global oil y/y demand growth (monthly, LHS, kb/d) vs real Brent price (RHS)



Source: IEA, UBS, DataStream

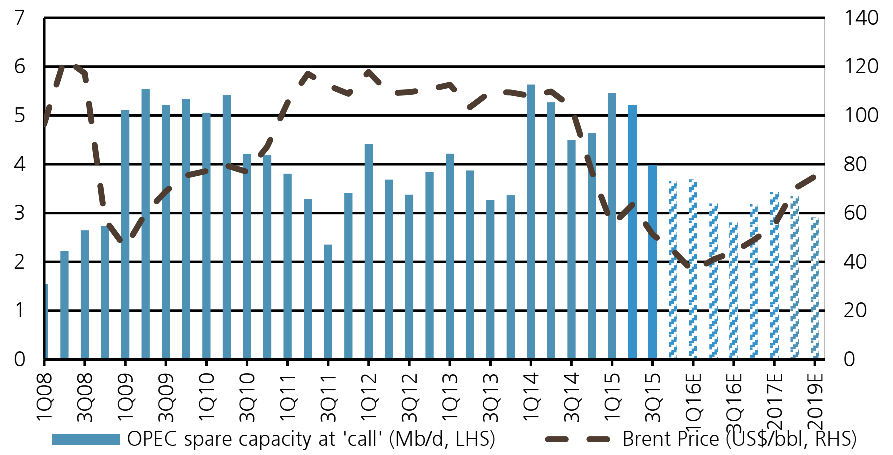
The final key aspect of the market is OPEC – in particular the group's spare capacity. In previous cycles, when OPEC acted to balance the market, the group's spare capacity could be interpreted as an indicator of flexibility in the global market – hence pricing tended to react as capacity became strained (on fears that any geopolitical supply interruptions could not be met out of OPEC, or more particularly Saudi Arabia's spare capacity). In the current cycle OPEC is acting not to balance the market – hence these figures ought to be interpreted somewhat differently: by deciding to produce out of its spare capacity OPEC is removing some of the flexibility from the market, and thus we believe that current market conditions imply a higher level of global inventories than historically has been the norm is warranted. Our preference is to examine hypothetical OPEC spare capacity were it to produce to balance the market – on this analysis current levels of spare capacity are not high by historic standards and are projected to fall meaningfully over the coming quarters (from a peak of 5.5Mb/d in 1Q15 to 2.8Mb/d by 3Q16, remaining around the 3Mb/d level over the balance of the decade). Finally we would also caution that current spare capacity figures are to some extent untested, while much of it is notional spare capacity rather than capacity that can genuinely be switched on at short notice – on the former point we note that Saudi crude production was running at record high levels throughout the summer months, while on the latter there is currently ~500kb/d in 'spare capacity' shut in in the Saudi-Kuwaiti neutral zone – capacity that is shut in due to a political dispute and where operator Chevron has pulled out most of the local workforce.

Figure 5: OPEC spare capacity (actual) vs Brent prices (RHS, $/bbl)



Source: IEA, UBS, DataStream. Note: 'Effective spare capacity' excludes notional spare capacity in Iraq, Nigeria, Libya and Iran. Spare capacity figures are calculated at actual OPEC output

Figure 6: OPEC spare capacity (at 'call') vs Brent prices

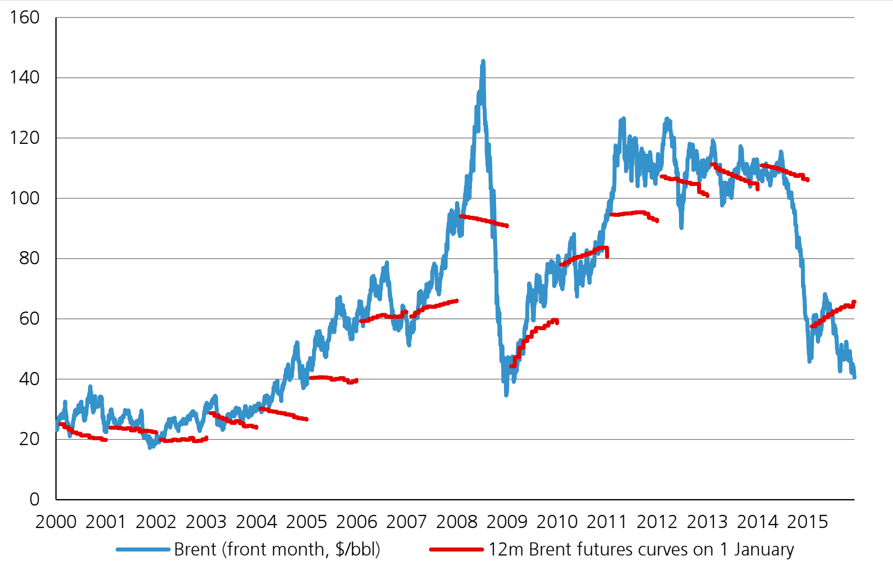


Source: IEA, UBS, DataStream. Note: hypothetical spare capacity figures calculated if OPEC were to produce at the 'call on OPEC crude' – i.e. to balance the market

How good a forecaster is the futures strip?

The futures curve has historically not been a good predictor of spot prices. Over the past 15 years, the difference between the 12m Brent contract on 1 January and the actual spot price on delivery date has averaged 29%. Furthermore, the extensive academic literature on the subject has, in general, concluded that the futures curve is not much better a predictor of spot prices than a random walk. This is in part because the futures curve is theoretically nothing more than the current spot price adjusted for interest rates, storage costs and a 'convenience yield' to consumers of holding inventory (the latter two in turn closely related to inventory levels - see our discussion of this below on page 29). We do however acknowledge that extreme contango or backwardation can highlight some sort of temporary stress on the front end – e.g. the relatively steep backwardation in early 2011 reflected disruptions to supply that were expected to be temporary (the Arab Spring impact).

Figure 7: The futures price as a forecast: Brent futures curves vs price outturn



Source: Thomson Reuters, UBS

Oil Supply

How much do you expect US and global capex to decline in 2016?

- **We forecast US E&Ps to reduce spending by ~39% YoY in 2016, resulting in a ~28% YoY reduction in rig counts and a 7% YoY decline in US oil production to 8.6 Mb/d.** This compares to current consensus which forecasts a lesser 25% YoY decline in 2016 capex. And it would mark a second consecutive year of sharply reduced spending following 2015's ~40% YoY decline. But despite the large reductions in spending expected this year, about half of US E&Ps in our coverage universe that have guided to YoY capex declines in 2016 have actually also forecast flat or increasing production, largely as a result of efficiency gains. Nevertheless, we expect most of these companies will need to revise their expectations down again given the plunge in oil prices since 3Q results and the prospect for large free cash flow deficits and stressed balance sheets; our forecasts imply a negative -11% FCF yield at current strip prices and an average debt/EBITDX ratio of >5x. While balance sheets clearly need to be repaired, even the ~39% YoY capex reduction we forecast implies a capex/cash flow plowback ratio of ~160% . . . implying further downside risk to capex if managements are truly committed to reducing financial leverage.

- **Global capex is expected to decline another ~15% YoY in 2016. According to Spears Research, drilling and completion spending (excluding Russia, China and Central Asia) is forecast to drop by 16% YoY to $182 billion in 2016.** Of the >70 companies in our Energy Capex Tracker which includes Canadian E&Ps and global majors, 20 companies (representing 56% of 2015 aggregate capex) have now released initial 2016 budgets, on average guiding to a ~15% YoY decline in spending. However, unlike the US, there is a greater lag time between a change in drilling activity and an impact on non-US non-OPEC production as numerous major capital projects are scheduled to come on stream in 2016-17 enabled because the bulk of the spending occurred over the past several years when oil prices, cash flows and spending levels were higher. In fact, we estimate roughly 30 major capital projects (excluding LNG) with peak cumulative capacity of >4 Mb/d are scheduled to come on stream in 2016, up from <25 projects with cumulative capacity of ~2.5 Mb/d in 2015. As a result, we forecast non-OPEC crude supply to fall by 0.8 Mb/d, or about 1.4% YoY, to 57.5Mb/d in 2016, with the call on OPEC crude increasing to 31.4 Mb/d from 29.6 Mb/d.

What is your forecast for US oil production in 2016?

- **We forecast U.S. oil production will decline 660 Kb/d YoY to 8.63 Mb/d in 2016, down 7.1% YoY** driven by a 11.1% decline from the four biggest shale plays (to 4.54 Mb/d in 2016) and a 9.4% decline in the rest of onshore production (to 2.40 Mb/d), partly offset by a 10.0% increase in Gulf of Mexico production (to 1.70 Mb/d). We expect U.S. production to bottom at 8.48 Mb/d in mid-2016 (a 1.1 Mb/d decline from the April 2015 peak of 9.585 Mb/d), and exit the year at 8.63 Mb/d which would be down an estimated 3.8% YoY.

- **We forecast total oil production from the four biggest shale plays to average 4.54 Mb/d in 2016, down ~11% YoY driven by a 28% YoY decline in average rig count in 2016, partly offset by continued rig productivity gains**. Roughly 95% of U.S. unconventional oil production comes from the "Big Four" shale plays (Permian, Eagle Ford, Bakken, and Niobrara), where we expect production to average 4.54 Mb/d in 2016 (down 11.1% YoY from 5.11 Mb/d in 2015E), bottom at 4.48 Mb/d in mid-2016, and exit the year at 4.58 Mb/d which is down 4.5% YoY and a 13.7% decline from its peak in March 2015. Behind this drop was a 50% YoY decline in average rig count in the "Big Four" to 539 in 2015, and we assume rig count stays flat in 2016 at the December 2015 exit level of 390, implying a 28% YoY drop in FY average rig count. This is consistent with our view that capex will decline 32% YoY. Meanwhile, we assume productivity per rig in the "Big Four" increases by ~3% per month, in line with the 2013-15 average rate albeit ~100bps slower than 2015.

How many rigs are required in the US to hold oil production steady?

- **We estimate a minimum of ~520 rigs would be needed in the "Big Four" oil shale plays and >720 oil rigs overall in order to hold U.S. oil production flat YoY in 2016.** The required rig count would presumably decline over time as US E&Ps continue to improve efficiency rates (defined as production per rig) through quicker spud-to-spud times and improved reserves per well. This assumes over half of the US shale rigs would be in the Permian, which has the largest reserves/well and is experiencing the most material efficiency gains given it is in the earliest stages of the learning curve when compared to the other 3 big oil shales in the US. We should note that the US would also need to run >200 rigs on conventional assets to enable flat production, implying an oil rig count of >720 would be needed to hold US oil production flat. For perspective, this compares to the peak US oil rig count of 1,601 in the fall of 2014 and the 2015 average of 750 and the current rig count of ~516.

Figure 8: US Rig Counts

	Total "Big 4"		Federal GoM		Rest of U.S.		U.S. Total	
	2015	2016	2015	2016	2015	2016	2015	2016
Base production decline (MoM)			**12.0%**	**10.0%**	**-0.4%**	**-1.0%**		
			(GoM: YoY chg. per month)					
Monthly rig addition (reduction)	**0.0**	**57.8**						
YE rig count	390	911						
YE rig count vs. 2014 peak								
Full year average rig count	539	737						
% change YoY in FY avg rig count	*-50%*	*37%*						
December production (MBbld)	4,791	6,515	1,626	1,789	2,558	2,267	**8,976**	**10,571**
YoY change	*-7.5%*	*36.0%*	*12.0%*	*10.0%*	*-7.8%*	*-11.4%*	***-4.6%***	***17.8%***
FY average production (MBbld)	5,108	5,197	1,542	1,696	2,646	2,398	**9,295**	**9,291**
YoY change	*11.6%*	*1.8%*	*10.4%*	*10.0%*	*-3.0%*	*-9.4%*	***6.8%***	***0.0%***

Source: UBS, Baker Hughes

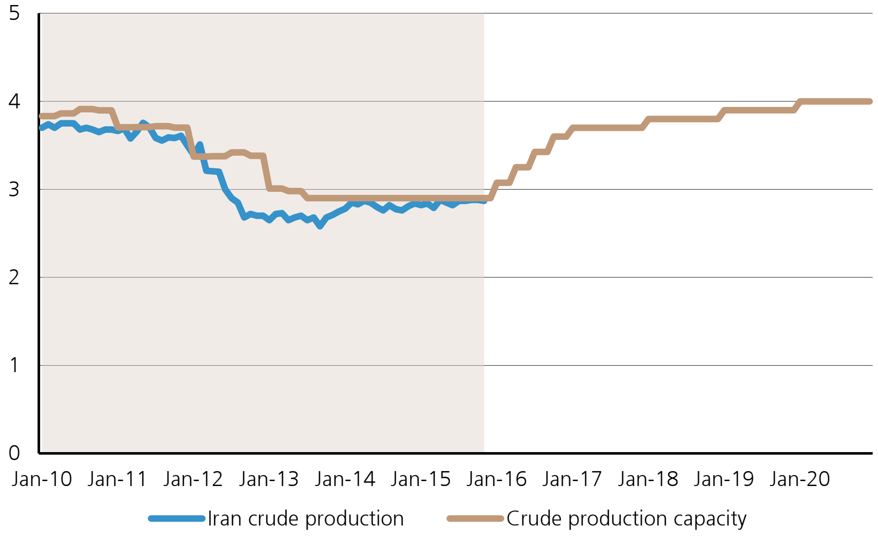
How much production do you expect Iran to add if sanctions are lifted and how quickly can it ramp up?

We expect Iran to ramp up to 3.6Mb/d by end-2016. Iran is OPEC's third-largest producer and the world's fourth-largest reserve holder. Production has declined to ~2.9Mb/d since the introduction of strict financial sanctions in 2012 (having averaged ~4.2-4.3Mb/d in the decade before). This meant that exports fell from ~2.2Mb/d to around 1.1Mb/d (slightly above the 1Mb/d nominal cap agreed under the November 2013 preliminary deal). The IEA estimates Iran's sustainable production capacity at 3.6Mb/d and we anticipate that production could be ramped up to this level within 6-12 months following any potential lifting of sanctions: for forecasting purposes we assume a gradual ramp-up over the course of 2016 to reach this level by year-end. Historically, Iranian production peaked at ~6Mb/d in 1974 (the first oil discovered was in 1908) but declined after the Iranian revolution of 1979 and the Iran-Iraq war of 1980-1988, not returning to 3Mb/d until 1990.

In the longer term however further production capacity increases will be contingent on access to IOC capital and technology. Iraq for comparison, although arguably less mature and with greater leverage to new investment, has added ~1.5Mb/d since 2004. In November 2015 Iran unveiled the framework of its new fiscal regime, the Iran Petroleum Contract, and presented the 52 development and 18 exploration blocks on offer. Woodmac reports that early life oil developments and EOR opportunities are being made available onshore along with offshore gas development and exploration across the country and in both the Arabian Gulf and the Caspian Sea. While the new contract structure is designed to improve the returns on offer we would expect the IOCs to be cautious initially – full technical details of the IPCs, including the cost recovery process and remuneration fee formula, are yet to be provided; while uncertainty over the implementation of US non-nuclear sanctions, and potential implications for companies also conducting business in the US remains, even if nuclear sanctions are lifted. Notably no US companies attended the Tehran conference in November, while BP stayed away from the initial British trade delegation. We therefore project only a slow build-out

of liquids production capacity to ~4Mb/d across the balance of the decade (WoodMac projects 4.5Mb/d of crude, condensate and NGLs by 2025, indicative of the potential from this huge resource holder but still short of the 5Mb/d routinely quoted by the media).

Figure 9: Iran crude production vs sustainable production capacity (Mb/d)



Source: IEA, UBS, WoodMackenzie

Can you quantify the scale of major capital projects deferred because of low oil prices and when will it impact global supply?

In a 'normal' year the industry sanctions 5-5.5Mboe/d of peak production through large projects – 2015 saw just 1.3Mboe/d reach FID. We estimate that the shortfall in project sanctions in 2015/16 more than equals the current over-supply in the market and could result in a very severe shortfall 4-5 years out.

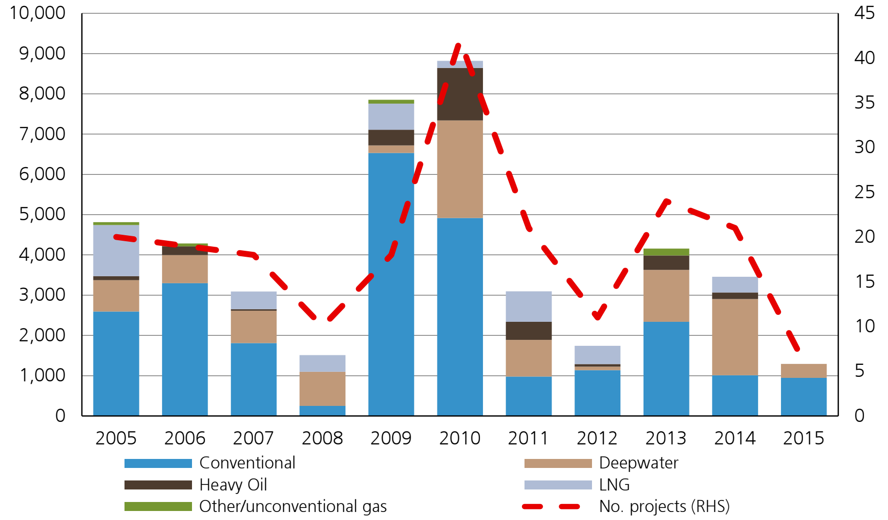
Projects are being deferred for a variety of reasons:

- Companies are unclear as to what the prevailing macro environment will be for their new projects and are re-examining their price assumptions;
- Companies are under significant budgetary pressure and liquidity and balance sheet require them to tamp down capital spending;
- There is a strong sense that project development disciplines have been lost and a 'time out' has been called as projects in the sanctioning and pre-sanctioning process are being re-worked;
- The industry is witnessing significant cost deflation and waiting on launching new projects may allow for significant contractor cost savings.

Historically, the large industry projects that we track as part of our Upstream Project Database (projects ≥ 75kboe/d) add around 5-5.5Mboe/d of peak production. We calculate that 2015-17 new start-ups will add an average of 5Mboe/d, all from sanctioned projects. However, we also calculate projects sanctioned in 2015 at only 1.3Mboe/d with oil at ~0.8Mboe/d. Furthermore we

see a level of sanctions in 2016 at not significantly more than this level for oil (somewhat more for gas but we see a high proportion of this at risk). This implies at the very least a shortfall of ~4Mb/d of oil production in the 2018-20 period.

Figure 10: Upstream major project FID



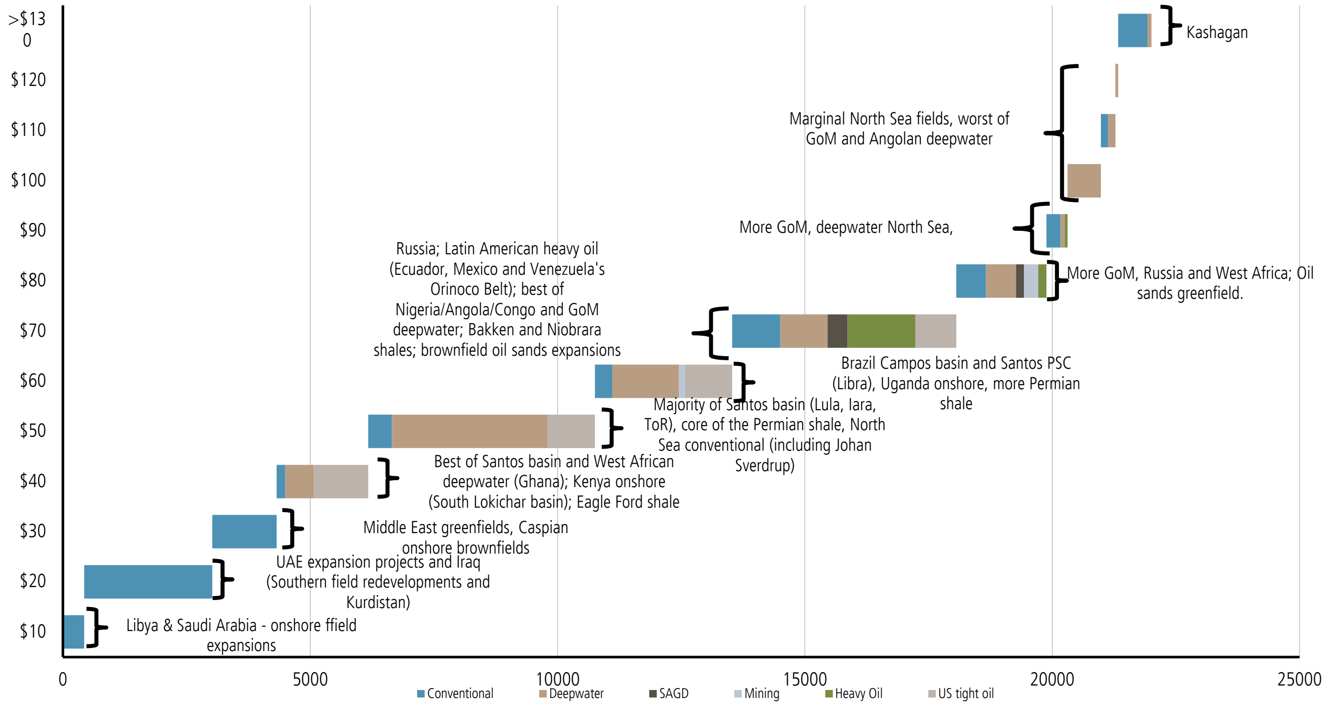
Source: UBS, Company Data, WoodMackenzie

Do you have a picture of the global cost curve and how much has it moved over the last 18 months?

Over the past 18 months we have seen considerable cost deflation work its way through the industry which, if sustainable, has a significant impact on the shape of the global cost curve. Our long-term price forecast of $75/bbl (Brent, cut from $80/bbl) is based on our view of the price required to generate an acceptable rate of return for the marginal barrel, adjusted for a project risk element. While industry cash costs of production lie well below $40/bbl, as the market goes through the rebalancing process it needs to appropriately incentivise new capacity. This process is quicker than often understood, because while oil demand grows only slowly (~1% per year) unmitigated decline of existing capacity is around 8-10% per annum (mitigated 3-5%).

The bulk of US tight oil production is not the marginal cost supplier: for the most part it lies comfortably in the middle of the cost curve. Cuts to investment in the short-term are liquidity driven and reflect the shorter cycle nature of production. In the longer term we expect the bulk of the adjustment in supply to come from areas such as West African deepwater, the North Sea, Canadian oil sands and other more challenging regions. This process is already clearly underway – 2015 saw just one major liquids project FID in West Africa (Eni's Cape Three Points, economics aided by domgas sales at >$9/Mcf) and two in the North Sea (Wintershall's Asgard tie-back Maria, and the giant Johan Sverdrup field).

Figure 11: Marginal cost of new oil supply 2015-20 (cumulative kb/d new production)

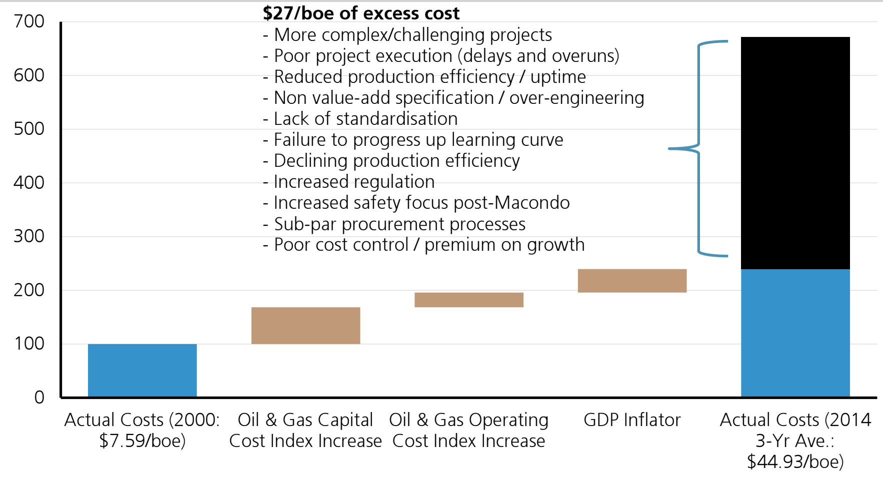


Source: UBS, WoodMackenzie. Note: Includes identified major projects with a material liquids component only (UBS' upstream database tracks identifiable projects at around the 75kboe/d level or larger as a means of sampling key project trends). 'Marginal cost' defined as Brent oil price required to generate full-cycle IRR of 10% for oil sands projects, 12% for conventional offshore and onshore projects, and 15% for deepwater projects.

Throughout 2015 we have begun to see considerable cost deflation work its way through the industry. Commentary from the major IOCs suggests prices for oilfield services and equipment have fallen 15-30% since the start of the downturn, and that the handful of projects able to reach FID during the downturn are benefiting from this (Shell referenced 20% in total project cost savings at Appomattox sanction in July). The few concrete datapoints we have corroborate this – Statoil for example has brought down unit opex in its international upstream business by 22% vs 2014, while the IHS CERA operating and capital cost indices (tracking a broad spectrum of direct input costs) are down 11% and 21% vs the 2Q14 peak as of 3Q15.

There is some doubt about the longevity of this however – a significant proportion is attributable to margin pressure on the oil service sector, some of which probably isn't sustainable in a recovering price scenario. That said, in the conventional oil production space it's clear that over the last cycle the industry's cost increase is only partly about direct costs from suppliers: we estimate that the 2014 cost base contained $27/boe in 'excess' attributable to poor project execution, over-engineering, an increased focus on safety post-Macondo and the prioritisation of growth (via high-cost basins) over returns. It is this base that operators are looking to attack in order to restore historic levels of return, and it is success here rather than simply squeezing the margins in the supply chain that will shift the supply curve down in a sustainable fashion.

Figure 12: Cost inflation: inputs vs. inflation vs. inefficiency - $27/boe excess cost

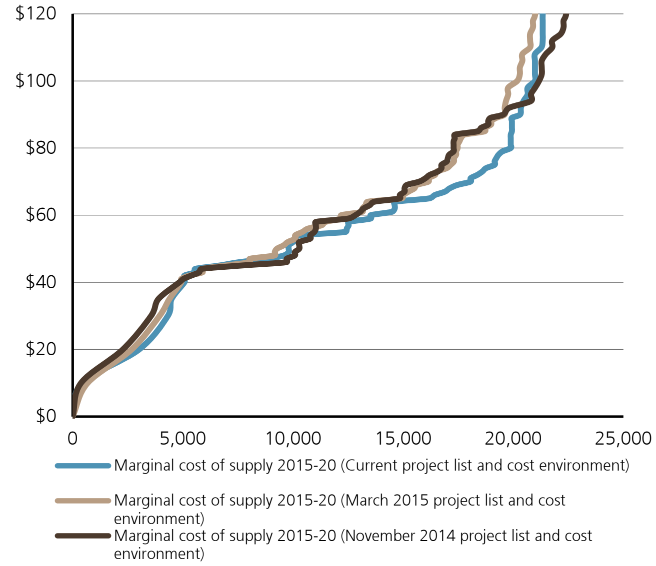


Source: UBS estimates; HIS Herold

Over the past 18 months there are two clear market effects that have begun to shift the cost curve. The first of these is the cancellation and deferment of projects in higher cost regions, leading to a contraction at the top of the supply curve and addressing the 'hockey stick' effect here. The second is the aforementioned process of re-evaluating development concepts and seeking cost improvements that is clearly underway, a process that ultimately ought to be structural (unlike purely supply chain driven cost deflation). We calculate that 87% of identifiable major projects coming on stream over 2015-20 generate a risk-adjusted rate of return at $75/bbl. This compares to 80% of projects in the March 2015 cost environment, and 73% of all projects in November 2014 (although the latter dataset includes a tail-end of high-cost West African deepwater and oil sands projects that have since been scrapped).

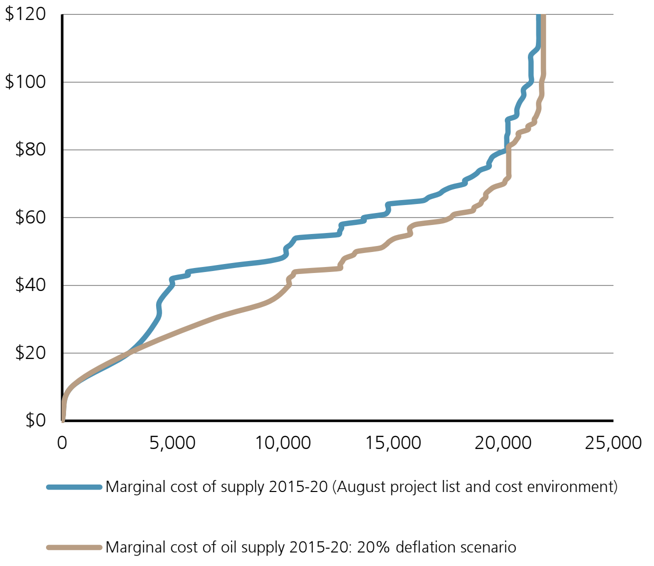
As an exercise, we have also re-run our supply curve putting through an additional 20% reduction in unit costs (both capex and opex) to reflect the type of structural change the industry may be able to bring about. The implications are significant: 65% of projects would generate economic rates of return at $50/bbl (vs 46% in the current cost environment). At $60/bbl this becomes 79% (vs 61%) and at $70/bbl 90% (vs 82%).

Figure 13: Marginal cost of new oil supply 2015-20 ($/bbl Brent) – evolution



Source: UBS, WoodMackenzie

Figure 14: Marginal cost of new oil supply 2015-20 ($/bbl Brent) – current cost curve vs 20% deflation scenario



Source: UBS, WoodMackenzie. Deflation scenario assumes 20% deflation in both opex and capex across the entire project list.

How 'short cycle' is short cycle US shale?

- **We estimate the US production response to a change in drilling activity is roughly six months, although we expect a somewhat delayed increase in drilling activity as industry emerges from this downturn after oil prices begin to improve given the severe damage done to balance sheets.** This is consistent with the US oil rig count peaking in September 2014 at 1,601 rigs and US oil production subsequently hitting a high of 9.585 Mb/d in April 2015 and the Big-4 shale plays peaking at 5.306 Mb/d in March 2015. The majority of US drilling activity is directed to development of liquids rich shales. And once these plays move from the exploration and appraisal stage to the development phase, operators typically develop the fields by drilling 6-8 wells per pad with 10-20 days from spud to rig release per well, with completion crews moving in behind the rig to complete wells over the next month. Importantly, we expect that it would take companies *more time to increase production* than to cut activity levels and output, mainly due to the time it takes to hire and train additional employees when ramping up. And during this cycle, the longer oil prices stay low, the longer it should take for US E&Ps to increase capex and therefore production as they prioritize balance sheet rehabilitation given the damage done to their financials and liquidity during this vicious downturn.

How has mature non-OPEC production (eg Canada, North Sea, Russia) reacted to low oil prices and why?

It was widely expected that mature non-OPEC production would come under pressure in a lower oil price environment. However, so far this has not been the case. Indeed, North Sea production is likely to be up around 100kb/d (+3%) in FY15; Canada up around 95kb/d (+2%) and Russia up around 140kb/d (+1%).

We ascribe this outcome to a number of effects:

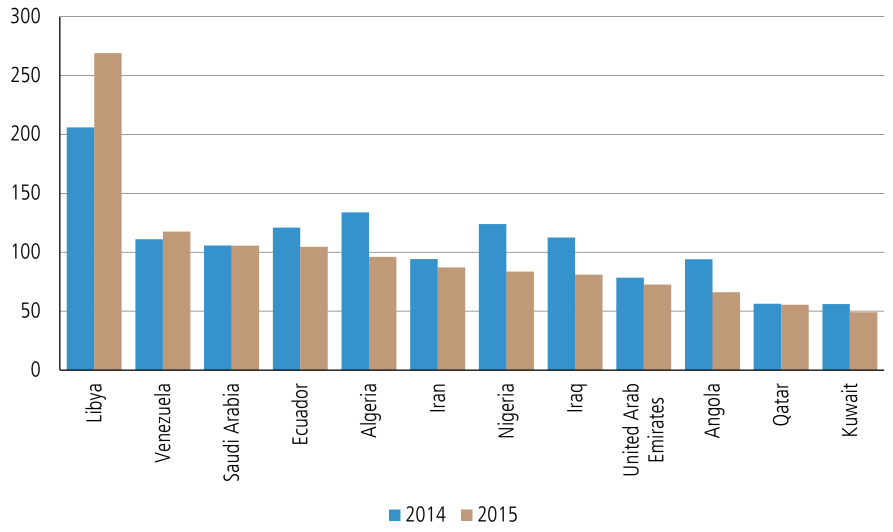
- The project cycle times involved means that the fall in the oil price has not yet impacted start-ups as yet.
- There has been a concerted effort to bring down costs. One way of reducing unit costs is to raise production. Some of this reduction in costs may be temporary – in October consultancy Rystad reported a dramatic decline of infill drilling in mature basins which it claims will result in a sharp decline in production in 2016.
- Lastly, costs have been helped by the linked decline in the value of the local currency as a result of the collapse in commodity prices (Russia, Canada, Brazil, Australia, Norway).

OPEC

What oil price do Saudi Arabia and the other OPEC members require over the long-term?

We estimate that Saudi Arabia's 2016 budget implies a fiscal breakeven of ~$80/bbl. Breakevens for the other Gulf producers lie at sub-$70/bbl although this figure varies hugely among other OPEC producers. Prior to OPEC's inability to agree to cut output in November 2014, a closely watched datapoint had been the oil price required for the major producers to balance their domestic spending needs – the logic being that fiscal and trade balances could be used to try to infer a likely price target for the group. These budget requirements had risen dramatically following increased social spending requirements in the wake of the Arab Spring, although we suspect the direction of causality has been from rising oil prices to budget inflation rather than the reverse (a state-level parallel to the capex inflation seen at the IOCs). This analysis is rendered irrelevant in the near term since budgets are set with the knowledge that they will be in deficit given price expectations (c.f. the 2016 Saudi budget) and inflexibility in short-term spending – although it remains an interesting test of financial stress.

Figure 15: OPEC fiscal breakeven ($/bbl Brent)



Source: IMF (MENA producers), Wall Street Journal (Venezuela), UBS (Angola, Nigeria, Ecuador).

Fiscal breakevens across the OPEC group vary hugely – from >$200/bbl for Libya (a function of conflict and depressed crude production) to sub-$50/bbl for Kuwait. The vast majority of producers have now begun implementing new fiscal measures in response to widening budget deficits – which ought to see these breakevens come down into 2016/17. In many cases the first victims of these budget cuts have been long-running domestic subsidies for oil products – with Saudi Arabia being the latest producer to raise domestic gasoline prices by up to 2/3 for some octane ratings.

The recent 2016 Saudi budget is relatively opaque – none of the three key moving parts of oil price assumption, non-oil revenues, or the impact of domestic energy price reform on oil revenues are identified. That said, if we assume non-oil revenues are flat y/y (in reality alternative revenue raising mechanisms will help, although offset somewhat by negative GDP effects) and that there is no benefit from domestic energy price reform assumed in the revenue forecasts, then the budget implies a planning oil price in the low $40s, and a 2016 fiscal breakeven of ~$80/bbl, $25/bbl below 2014/15. There are significant risks to this figure in both directions however. On the one hand Saudi has historically tended to overshoot its initial spending estimates – SR 975bn in actual spending in 2015 vs a SR 860bn initially budgeted, and SR 1,100bn in 2014 vs the budget of SR 855bn. Every 10% in overspend in 2016 would push the fiscal breakeven up by $10/bbl. On the other hand, the IMF estimates the implicit cost of Saudi's domestic product subsidies at ~$10bn – allowing prices to appreciate to comparable international levels could improve the fiscal breakeven by $5/bbl.

Figure 16: OPEC fiscal/monetary responses to lower oil prices

Country	Announced measures
Algeria	Public sector hiring freeze, postponement of infrastructure projects. Ending fuel subsidy currently "not on the agenda". Supplementary 2015 budget law adopted in July cutting capital spend by 2.75%.
Angola	Removed domestic fuel subsidies in April – gasoline prices increased 28% over 2 weeks in Luanda.
Ecuador	2015 budget cut by $1.4bn in January and then a further $0.8bn in August in light of lower oil prices. 2016 budget to include a reference price of $40/bbl and deficit of 2-2.5% of GDP (compared to 5% in 2015). Budget expected to be approved in November.
Iran	Gradual depreciation of currency peg in line with inflation. 2015/16 budget increased VAT and reduced tax exemptions.
Iraq	2015 budget increased non-oil taxes, oil ministry has requested development spending cuts at major oilfields and is considering reforming current service contracts.
Kuwait	2015/16 budget includes an 18% cut in public sector spending. Fuel subsidy reform with ~0.5% of GDP impact.
Libya	No major policy response announced – unsurprising given lack of united central government.
Nigeria	Major reform of NNPC and new CEO has a mandate to improve oil revenue collection.
Qatar	No major policy response announced – budget frozen at 2014 levels although in recent years actual expenditure has run significantly above target.
Saudi Arabia	Large fiscal spending package worth ~4% of GDP announced in February 2015 following leadership change. July saw first sovereign debt issuance since 2007 and the country has now issued $26bn in bonds, increasing debt/GDP to 5.8% from 2% at end-2014. 2016 budget contains comprehensive economic reforms, including alternative revenue raising mechanisms and an increase in domestic fuel prices.
UAE	Removed fuel subsidies worth ~$7bn per annum at the start of August. Tariffs on water and electricity raised in January 2015 saving 0.5% of GDP.
Venezuela	Printing bolivares to cover widening budget gap – reports of domestic inflation running >100%.

Source: UBS, IMF, Wall Street Journal, Bloomberg, Reuters

Has OPEC given away its role as the marginal supplier to shale forever? Will OPEC be relevant again?

This is a common question. But we believe it needs to be re-framed. The November 2014 OPEC meeting was not a decision *by* the producer group not to cut production. It was the *absence* of any decision to change production. The absence of a decision came about because Saudi Arabia (and its GCC allies) did not want to cut (regarding it as a decision that placed disproportionate burden on them). Since that date OPEC production has actually risen – November 2014 crude production was 30.32Mb/d in the context of OPEC capacity of 34.17Mb/d; while November 2015 production was 31.73Mb/d in the context of 34.78Mb/d. OPEC liquids production accounts for ~40% of the market. Our observation that OPEC countries have contributed to the physical over-supply by producing a higher proportion of the pre-existing production capacity also implies it will have less flexibility going forward.

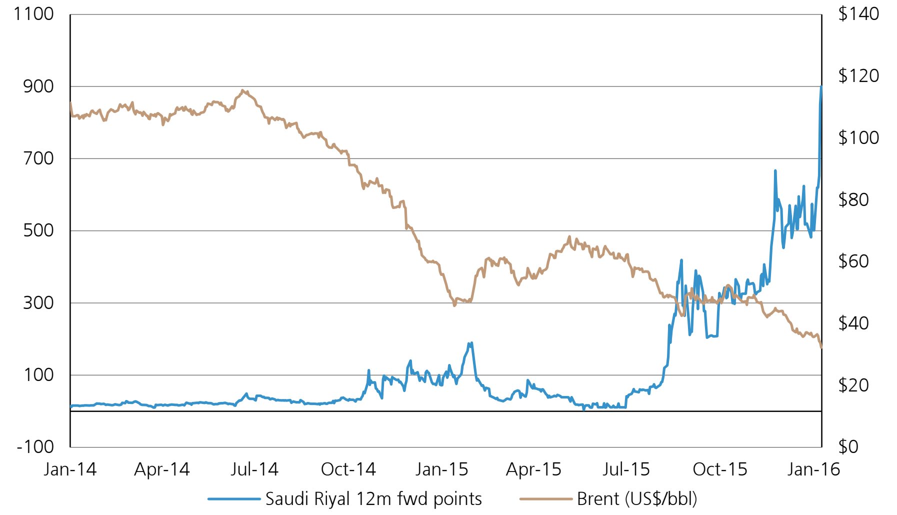
US shale is shorter cycle than conventional production but clearly longer to respond to price signals than spare capacity. But OPEC is using more of it capacity which means its flexibility will be reduced. Therefore increasingly shale will be the swing producer.

Since its creation in 1960s and increasingly since the 1970s OPEC has been very influential in the crude oil market. But the structure of the group with differing resource bases, short/long term objectives and scale makes it often quite unstable. In the absence of effective spare capacity and with the differing objectives among the members it is increasingly difficult to see how OPEC can be relevant in the current market.

If oil prices stay low for an extended period, is it likely Saudi Arabia de-links its currency from the US$ and what would the implications be?

We believe a Saudi devaluation is unlikely. Somewhat inevitably given the decline in oil prices over the past 18 months and the presence of a significant budget deficit, 2015 has seen significant speculation that Saudi may seek to de-link its currency from the US$. This has been exacerbated by events at other major oil exporters – Kazakhstan (oil and gas 65% of exports, 50% of government revenues and 25% of GDP) moved to a floating exchange rate regime in August 2015 while Azerbaijan (oil and gas 95% of exports, 75% of government revenues and 40% of GDP) did so in December. Typically speculation against the Riyal tends to be in the forward market – so the 12m forward premium can be used as an indicator of interest in a devaluation. This currently stands at ~900bps, after spiking from ~500bps in the first week of January, a level not seen since 2002/03 or the 1997/98 oil price decline before that.

Figure 17: Saudi Riyal 12m forward points vs Brent



Source: DataStream, UBS

We do not think a devaluation is likely. The Saudi Riyal has been pegged against the US$ at a rate of 3.75 since 1986, and has successfully endured a number of crude price collapses since: the 1998 Asian economic crisis, the September 2001 post 9/11 crash and the 2008/9 recession. Furthermore, the official stance of the central bank remains that the peg will be maintained for the foreseeable future (reiterated in an official statement on 11 January which argued recent volatility

resulted from investors' 'misperceptions' about the Saudi economy). The Saudi Arabian Monetary Agency had $635bn in reserve assets at end-November, enough to support the November burn rate for >4 years (or ~6 years at the 2015 average burn rate). While this is the lowest level since September 2012, it is important to put this in context: Saudi only began accumulating significant foreign reserves in 2005 and had held just $5-30bn in reserves over the prior 20 years. The Riyal has also endured speculative pressure greater than that being experienced at the moment – in August 1998 the 12m forward premium reached 950 points as speculators attacked the peg in light of falling oil. While we cannot rule out a devaluation (and the economics of currency crises suggest that if a devaluation were to come it would be well in advance of reserves actually running out), Saudi's ability to defend against previous episodes of speculation despite a much lower reserve base suggests to us that it remains an unlikely outcome.

As a significant commodity exporter but a major importer of both consumer goods and equipment the primary beneficiary of any devaluation would be Aramco and the Saudi government, with a windfall gain from US$-denominated exports but the majority of spending (e.g. public sector salaries) Riyal-denominated. Consumers by contrast would suffer due to import exposure – and so any decision to devalue would be politically contentious.

Oil Demand

How much of the 2015 demand surge was price-driven?

With Brent down 46% y/y and WTI down 48% y/y we estimate a demand impact of some 0.6-0.7Mb/d vs 2014 based on our analysis of historic price elasticity. 2015 was likely the strongest year for oil demand growth since 2010 and the 4th strongest in the past 20 years – we expect that when the final data is in total product demand will be up some 1.7Mb/d vs 2014. There are a number of effects at play here (1Q15 saw some benefit from a colder European and North American winter than 2014; tax cuts in China on small-engine passenger vehicles impacting gasoline demand growth) but for the most part this has been driven by the price impact.

There are two channels at work here. The first is a degree of substitution – while for the most part oil has been displaced by other energy sources for power generation (at least in the OECD world) there is some substitution at the margin (the UK for example will likely see diesel generators used as backup capacity over the coming year). More importantly lower oil prices, however fleeting, have a significant impact on consumer behaviour. US miles driven are up 3.4% in the year to end-October as a consequence of lower gasoline prices although the impact is lesser elsewhere where taxes make up a much higher proportion of the pump price (and so consumer's leverage to a crude price change is less). Investment decisions are also impacted – Chinese and US SUV sales are up 53% and 8% in 2015 respectively (China to end-November, FY15 for the US), driven in no small part by an expectation of lower fuel costs, and this is a price-driven demand source that will not reverse out in the same manner as a simple increase in miles driven.

There is also an income effect – for oil-importing countries (like most of the OECD world) lower crude prices provide a windfall benefit to GDP, some of which is in

turn spent on consuming energy, including oil. The IMF for example has estimated that a 40% decline in oil prices would result in a 1% increase to global GDP, assuming full pass through to consumer prices, or 0.5% assuming that countries that manage energy prices (e.g. China, Russia, Brazil and India) limit the pass through to consumers and save the resulting fiscal windfall. Isolating these effects separately in order to estimate their relative magnitudes is, unfortunately, nigh on impossible given that in most consumers' decision making processes both factors are at play (I will buy a new SUV because a) I have more money in my pocket and also b) I expect lower fuel costs so the cost of running a less efficient vehicle will be lower).

What is your 2016 and longer term demand growth?

We estimate that the oil market will grow by 1.3Mb/d in 2016. This compares to the latest estimates by the IEA/EIA/OPEC of 1.2/1.4/1.3MB/d and trend growth of 1.0-1.1Mb/d. The slightly above average growth is driven by some continued price-related effects (our 1Q16 Brent forecast is 35% below 1Q15) and an expectation that our forecast price recovery in 2H16 has only a limited impact on product demand (some of the price-related demand gains from 2015 will be persistent, like the aforementioned SUV sales increases). Downside risks to this figure are primarily weather related – a continuation of the mild December in North America and the OECD would see some reduced demand for heating oil than we currently project.

Over the remainder of the decade we expect demand to grow by 1.0-1.1 Mb/d, slowing gradually and driven entirely by the non-OECD world (we expect OECD demand to revert to structural decline post 2016). In the longer term we anticipate the oil product demand could peak towards the end of next decade or in the early 2030s as penetration of alternative energy sources for transportation increases dramatically, given impetus by continued progress on climate negotiations after the relatively successful Paris conference (which included a requirement for countries to revisit their commitments every 5 years, beginning in 2020).

How sensitive is global demand to fluctuations in the US dollar? And Chinese GDP?

As a US dollar priced commodity, unsurprisingly currency fluctuations have a meaningful impact on global demand given the exchange rate passthrough: **De Schryder and Peersman in 2014 estimated the impact of a 1% appreciation in the US dollar on global oil demand as -0.64%, after controlling for the US$ price** (given that there is also a significant correlation between crude prices and the US$).

A slowdown in Chinese GDP growth to 4% in 2016 (rather than 6.2% as UBS currently forecasts) would depress Chinese demand by 130-150kb/d or ~0.15% of global consumption, we estimate. The channels for this are twofold: gasoline demand growth slows following a likely deceleration in vehicle sales, although remains in the mid-single digits as consumption stays relatively robust and the impact of the recent vehicle tax cut works its way through. Demand for middle distillates and fuel oil however is harder hit by declining fixed investment: both directly through the generally reduced level of industrial activity and indirectly as lower coal use reduces rail/trucking requirements.

More meaningful however are the second-order effects. We estimate that the wider deceleration in the global economy triggered by a Chinese slowdown (for more detail see our global economics team's Q-Series, 'The Dragons Tail') would impact 2016 demand growth by 300-400kb/d. In conjunction with the impact on Chinese demand this implies 2016 demand growth of ~0.6Mb/d or up to 50% lower than our base case estimate. **While this remains small in the context of the overall market (~0.55% of current consumption), it would likely make rebalancing a 2017-18 event rather than 2H16 as we currently forecast**, although the swing factor here is more likely to be OPEC or US onshore output given the fine margins involved. However the possibility of greater second order effects on other economies; the fragile nature of oil market recovery; sentiment in a market focused on every bearish datapoint; and price sensitivity to fine margins suggests an impact of at least $10-15/bbl on our forecasts and argues for 2016 prices exiting roughly flat vs current levels (implying Brent would trade below $40/bbl for meaningful periods of time). We would also expect that the trajectory of price recovery we currently project (beginning meaningfully in 2017 and then reaching our normalised long-run assumption of $75/bbl by 2019) would be delayed by each year of similar sub-trend demand. There is also a significant risk that with another year of depressed prices (and depressed upstream investment as a consequence), the eventual price recovery would be much sharper than we currently predict.

How sensitive is oil demand to global GDP?

We estimate that 100bps on global GDP growth is worth ~500kb/d on global oil demand. However, far more important that the overall level of global growth is the geographic distribution of said growth – oil demand intensity (oil demand per unit of GDP) in the OECD world is significantly below that in the developing world – and hence global oil demand is much more highly levered to growth rates in the large non-OECD consumers (China and India in particular) than to the major OECD economies.

Will a slowdown in global refining capacity growth impact demand in 2016?

Refining capacity growth ought not to impact *demand* – but may affect apparent consumption. The impact is negligible in terms of the global market however. In line with the other forecasting agencies we typically measure and project oil product demand, rather than crude oil demand. Thus in a theoretical sense refining capacity growth ought not to have any impact on global demand – we are inclined to agree with most mainstream economists in rejecting Say's Law: supply does not create its own demand. That said however what we are able to observe (and thus base our projections on) is oil product consumption (typically indirectly through import/export and production data adjusted for stock changes) rather than demand – which can certainly remain constrained by a lack of supply (we would argue that the LNG market over the last few years represents a prime example of latent demand that cannot be fulfilled by available capacity). This is less relevant for the oil market however with global refining capacity running at <80% utilisation in 2014.

However this is not to say that there will not be an impact on crude markets. Typically in advance of starting operations a new refinery will purchase some crude to hold in inventory – thus a 'warranted' source of stock builds that can help dampen any oversupply. **We expect 0.97Mb/d of net new crude distillation**

capacity additions in 2016 – lower than 2015's 1.24Mb/d and 2012-13 but actually higher than 2014. Assuming that ahead of a new CDU starting up refineries fill inventory to cover 7 days' worth of throughput, the 2016 figure would represent ~7Mbbls in 'warranted' inventory builds – or just 20kb/d if spaced evenly throughout the year, with the y/y fluctuations relatively inconsequential in the context of the overall market.

Will the industry remain challenged to meet global gasoline demand growth in 2016?

We anticipate that global gasoline demand will grow by 0.9% in 2016 – after a strong 2015. By contrast we expect global gasoline production capacity to grow by ~1.5%. Thus while we expect that gasoline cracks will continue to demonstrate significant seasonality (OECD gasoline demand alone is typically 500-700kb/d higher during the summer months due to the driving season), we do not believe that on a FY basis the industry will be challenged to meet demand growth.

Other

Have you changed your oil S/D forecast?

We have raised our 2016 demand growth forecast by 240kb/d, and cut our 2016 non-OPEC supply growth estimate to 0.8Mb/d vs our last major balances update in September. Since our last major update in September 2015, we have made changes to our global S/D balances incorporating the latest round of capex cuts and project deferrals on the supply side, along with a more conservative US rig count assumption and more optimistic demand forecast consistent with our now lower projection for 2016 crude prices.

We have raised our 2016 demand growth forecast by 240kb/d, in addition to a 50kb/d revision to our baseline 2015 estimate reflecting some historical data revisions by the IEA and national statistics agencies along with the strong 3Q15 outturn with the final data now available. Note that this includes a 70kb/d reduction to our 4Q15 figure, in part reflecting the warmer-than-usual weather in the OECD.

On supply we have increased our 2015 non-OPEC supply estimate by 180kb/d since September. This is driven almost entirely by the US where production has proven more resilient to lower oil prices than we anticipated. **However, we have cut our 2016 non-OPEC supply growth estimate by 360kb/d and now expect non-OPEC supply to contract by 0.8Mb/d this year**. This is driven by 3 factors: a lower assumption around US output based on belief that at current oil prices, financial constraints and a continued depressed level of activity will see production roll over meaningfully; incorporating some project deferrals and indeed cancellations (Shell's Carmon Creek for example was originally slated for a 2016 startup); and a belief that a meaningful amount of non-OPEC production that is cash-negative at current oil prices may begin to be shut-in as the current downturn persists for longer.

These combine to give a 'call on OPEC crude' of 32.0Mb/d by 2H16 – enough to incorporate current levels of output plus some additional Iranian barrels. This compares to 31.5Mb/d that we had forecast in September.

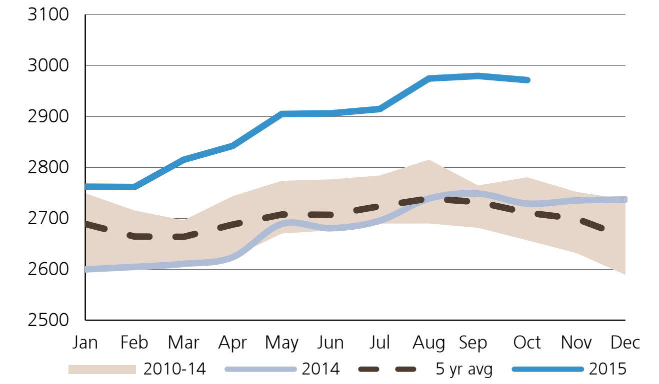
Will storage fill up? What is global capacity for storage?

We see sufficient global storage capacity and do not believe a 'tank-top' scenario is likely. In September 2015, OECD commercial inventories reached an all-time high of 2,979Mbbls. In conjunction with the prospect of an oversupplied market until at least 2H16 (and potentially longer if Iran is able to return greater volumes to the market than we currently expect, or if US supply continues to prove resilient to lower oil price) it's not surprising that investors are concerned about a 'tank-top' scenario. Such a scenario would suggest distressed pricing for crude, at least on a regional basis, and could presage a collapse to cash costs until the oversupply clears (<$30/bbl or lower to prompt sufficient volumes to be shut in).

However, we don't believe such a situation is likely. Our S/D balances, assuming OPEC holds output flat at 31.7Mb/d, imply global inventories build by 216Mbbls from end-October 2015 before stocks begin drawing in 3Q16. New Iranian supply however likely means a further 60-120Mbbls of inventory builds (depending on the speed of ramp-up) before we reach a roughly balanced market in 2H16, with meaningful inventory drawdowns then beginning in 2017.

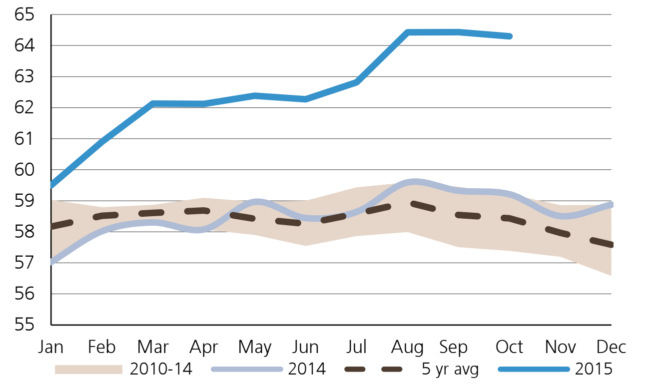
Our analysis of historic inventory peaks and utilisation data suggests a little over 300Mbbls as a baseline for the minimum available crude storage capacity in the OECD. Thus even if inventory builds over through to 3Q16 consist solely of crude, and are solely located in the OECD, we believe there is enough storage to accommodate our base case S/D balances. Clearly the margins are fine when looked at in this manner – but in reality inventory builds ought to be divided between OECD crude, OECD products (where we estimate at least 260Mbbls in additional capacity) and non-OECD countries (where inventory data is more opaque, but we estimate close to 200Mbbls as a minimum level of available crude storage based solely on known SPR, refinery and commercial storage facility startups in 2H15/2016). In aggregate this gives a baseline estimate for global storage capacity at ~750Mbbls: more than enough to accommodate our base case S/D balances and a rapid Iranian return. Our estimates also exclude existing non-OECD spare capacity and floating storage options – both of which would provide a further buffer. While we cannot rule out the possibility of a 'tank-top' scenario, we do not believe that it is a likely outcome.

Figure 18: OECD commercial inventories (Mbbls)



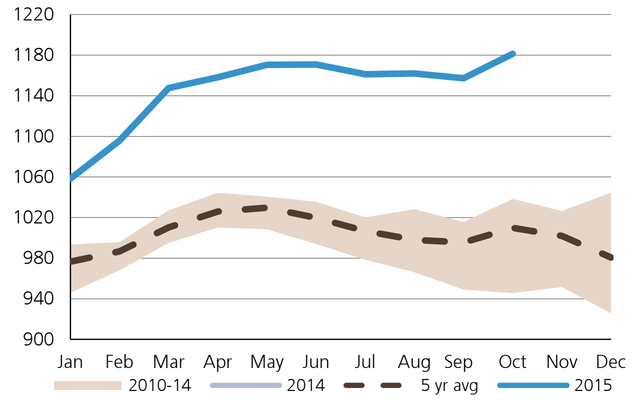
Source: IEA, UBS

Figure 19: OECD commercial inventories (days fwd demand)



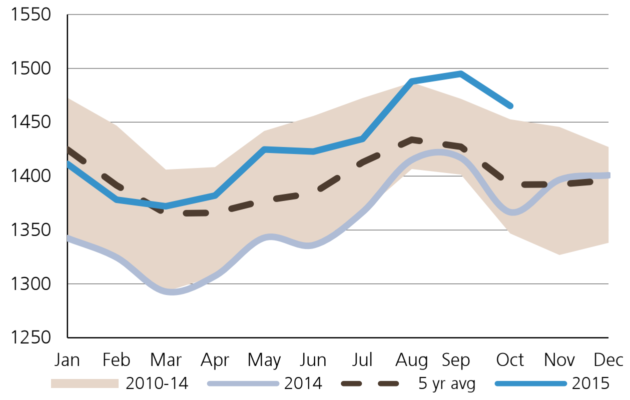
Source: IEA, UBS

Figure 20: OECD commercial crude inventories (Mbbls)



Source: IEA, UBS

Figure 21: OECD refined product inventories (Mbbls)



Source: IEA, UBS

Figure 22: Available global storage capacity

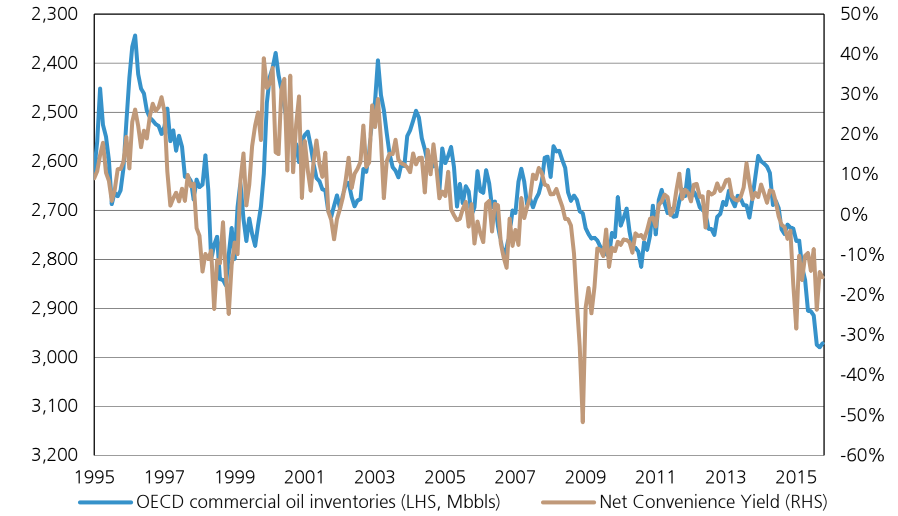
Storage category	Mbbls storage available	Methodology
OECD ex-US available crude storage	163	Difference between current crude inventories and 10-year country-level peak, adjusted for refinery distillation capacity additions/closures over the period to 2015 (we assume that refineries require crude storage to cover 7 days' worth of intake)
US available crude storage	143	End-September EIA tank farm and refinery crude storage capacity disclosure, adjusted for commercial stock builds in October-December weekly DoE data. We assume 90% utilisation is the practical maximum level as transportation systems require some working storage available to be filled at all times to receive pipeline deliveries etc.
OECD refinery capacity additions/closures in 2016	-2	415kb/d in US capacity additions next year less 713kb/d of closures (Europe and Japan) - assuming 7 days of crude storage
OECD commercial storage capacity additions	37	New European and North American storage terminals due to start up in 2016 - IEA estimate
OECD crude storage	**304**	
China SPR facilities	132	2H15 and 2016 new SPR facilities - Zhoushan Phase 2, Jinzhou, Huizhou, Yangpu, Kintan and Zhangjian
India SPR facilities	35	Visakhapatnam, Padur and Mangalore facilities, less 4 VLCCs of crude already purchased for the Visakhapatnam facility.
Non-OECD commercial storage capacity additions	26	IEA estimate
Non-OECD refinery capacity additions/closures in 2016	3	1,246kb/d in non-OECD capacity additions next year - assuming 7 days of crude storage
Non-OECD crude storage	**196**	
OECD product storage	**266**	Difference between current product inventories and 10-year country-level peak. Assumes no impact from refinery closures - in reality a significant portion of mothballed refineries have been converted into product storage terminals so we believe this a fair assumption.

Source: IEA, Bloomberg, Indian Strategic Petroleum Reserves Limited, EIA, Platts, UBS

What are the price signals for inventory reaching a critical level?

Contango of ~$1/bbl per month would be required for floating storage to be viable, and so the shape of the curve acts as an indicator of inventory stress – the M1-M12 spread currently stands at $8.50/bbl. As we discussed at length in last month's Monthly Agency Data Snapshot, there is a close theoretical link between inventory levels and the shape of the futures curve – at higher inventory levels the cost of storage rises, while the marginal benefit of holding additional crude (to more rapidly respond to sudden supply interruptions or demand shocks) diminishes. Thus, all else equal, arbitrage pressure from potential cash-and-carry trades ought to mean than contango emerges during periods of inventory gluts. This is a link that is also borne out in practise – the steepness of 12 month contango is highly correlated with inventory levels, as we demonstrate below.

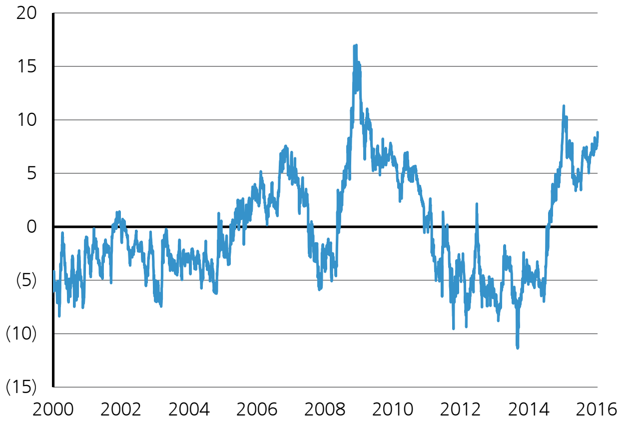
Figure 23: Net convenience yield (RHS) and OECD oil inventories (LHS, Mbbls, scale inverted)



Source: IEA, Thomson Reuters, UBS. Note: net convenience yield calculated as risk-free rate (annualised) less log of the ratio of the 12m futures price to the spot price.

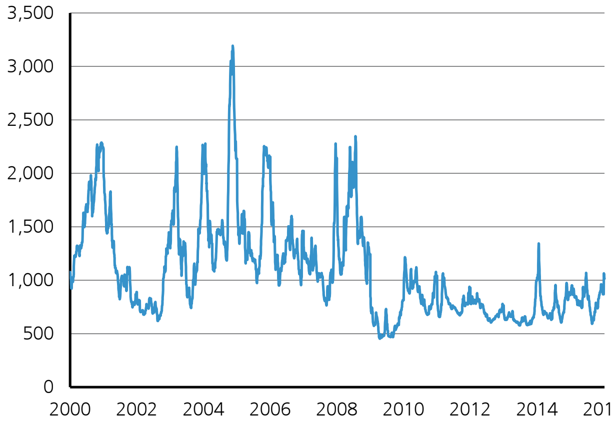
By the same logic, the shape of the curve acts as a real-time and market-based indicator of a potential tank-top scenario – and the first indications of an inventory crisis will likely be borne out here rather than in OECD inventory data that is released only on a 2-month lag. Were onshore storage to approach tank tops, then crude tankers would begin to be chartered for use in floating storage. A contango of ~$1/bbl per month is generally thought to be needed to make floating storage viable. The M1-M12 Brent spread currently stands at $8.50/bbl, insufficient for this trade to be profitably at current tanker rates and well below the $17/bbl reached in the 'super-contango' of December 2008. Furthermore, were the floating storage window to open, tanker rates would respond rapidly – any sudden spikes in the Baltic Dirty Tanker Index in conjunction with a sufficiently steep contango could be interpreted as an indication that traders are chartering VLCCs for storage purposes.

Figure 24: M1-M12 Brent contango ($/bbl)



Source: Thomson Reuters, UBS

Figure 25: Baltic Exchange Dirty Tanker Index



Source: DataStream, UBS

How does geopolitical risk interplay with oil prices?

Historically, the oil price has been sensitive to political risk, especially in respect of the important Middle East region. We currently see remarkably little geopolitical risk priced in to oil currently. This is despite the active fighting in Syria and Iraq against ISIL/DAESH, the fighting in Yemen, which has in the past been regarded by the Wall Street Journal and other media sources as a proxy war between Sunni Saudi Arabia and Shia Iran, and the continuing problems in Libya after the overthrow of Colonel Gaddafi in 2011 following the Arab Spring.

We should also note that low oil prices can also generate increased political risk which in turn creates risk to the oil market. The stability of many of the exporting countries within OPEC are critically reliant on the revenues that oil generates for them.

Are oil prices in the new world order likely to less or more volatile?

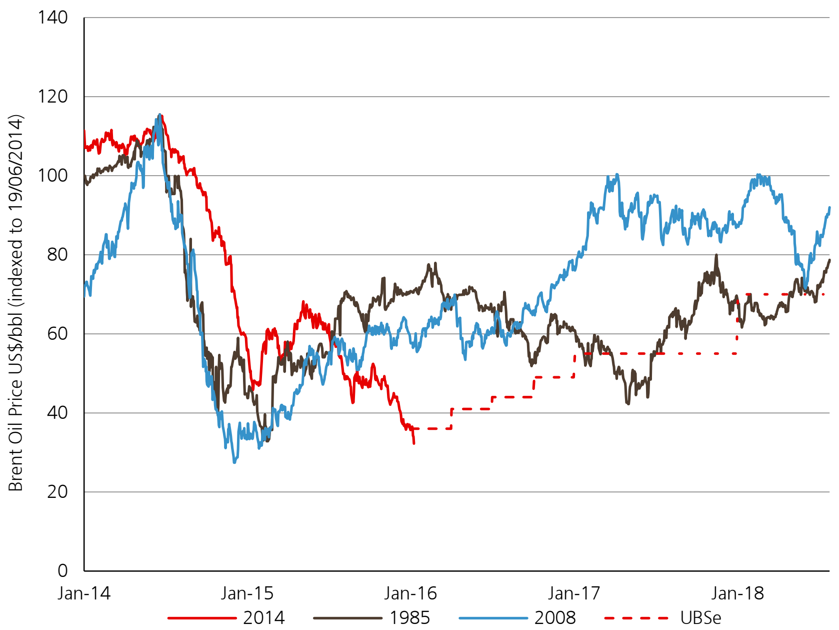
We see the market becoming more volatile and not less. The investment cycle for conventional non-OPEC production is at least 3-5 years and in many cases considerably longer. While it has been widely discussed that US tight oil production is shorter cycle, which it evidently is with initial production responses to price signals taking, perhaps, 6 months as we discuss above, there is still considerable scope for the market to tighten or loosen in response to a supply/demand shock before any adjustment can be made. And while OPEC retains the theoretical facility to remove production from the market in response to future over-supply situations if it is to work from a higher production base going forward then its capacity to adjust production upwards via its spare capacity is severely limited. Historically, OPEC has run with effective spare capacity of 4-6Mb/d (and >10Mb/d in the mid-1980s price collapse) but this has now shrunk to only 2.3Mb/d and with the call on OPEC likely rising over the coming years we see limited prospect of this important adjustment mechanism getting bigger.

How does this oil price crash compare with others in amplitude and length?

The current oil price collapse is no more severe than either the 1985 or 2008 downturns. The oil market is given to periodic crises, and to some extent the current downturn is simply another cycle. Viewed through the lens of historic collapses the trajectory of price recovery that we currently project doesn't appear overly optimistic, nor does the depth of the trough seem out of the ordinary (rather it has simply been reached a little later than in 1985 or 2008).

In 1985 and 2008 the oil price bottomed at the same and 4% below current levels in relative terms, and in each case the collapse was more rapid. During 2008's demand-driven crash crude took just 6 months to reach a trough 76% below the peak, remaining there for ~3 months and beginning a fairly steady recovery that would see it back above $100/bbl by February 2011, 2.5 years after the collapse began. 1985 by contrast, while similarly rapid on the down-cycle, took much longer for crude to see any meaningful price recovery. Ultimately it took the introduction of UN sanctions on Iraqi and Kuwaiti output in August 1990 to bring crude out of the trough. We see the trajectory of price recovery from the current downturn as somewhere between the two cases: the collapse was driven primarily by the supply-side (although exacerbated by a sluggish year of demand growth), with readjustment here a relatively slow process. However, levels of OPEC spare capacity are much lower than in 1985: ~3.5Mb/d at the 'call' or ~2.3Mb/d at current levels of OPEC production vs >10Mb/d in 1985, and the supply-side adjustment process more rapid this time as a result.

Figure 26: Historic oil price falls vs 2014 – pre fall peaks indexed to June 2014 peak of $115.50/bbl



Source: DataStream, UBS

LNG

How much LNG capacity is coming over 2016-19?

There is ~140Mtpa of LNG export capacity under construction presently, roughly equivalent to half the existing global capacity.

That being said 2015 was another year when the LNG supply story didn't play out. Our preliminary data for 2015 suggests that trade was up approximately 2% y/y (around 1% above our modelled estimate). Start-ups in 2015 were BG Group's QCLNG and Santos' GLNG. 2015 also benefitted from the ramp-up of ExxonMobil's PNG LNG but some slight reductions from traditional exporters and a shut-in of the Yemen LNG facility.

With the caveat so evident in 2015 that supply rarely meets expectations we expect the coming years to be big for new LNG supply. We forecast a 9% cagr in LNG supply across 2016-18. Indeed we forecast ~8% cagr over 2016-20.

Exports from Santos' GLNG are expected to begin imminently. And in 1Q we also expect cargoes from Chevron's delayed Gorgon project and its interrupted Angola LNG project. Also perhaps most meaningfully 1Q may also see the start-up of exports from the US with Sabine Pass T1 expected around the end of January.

Figure 27: LNG projects currently under construction

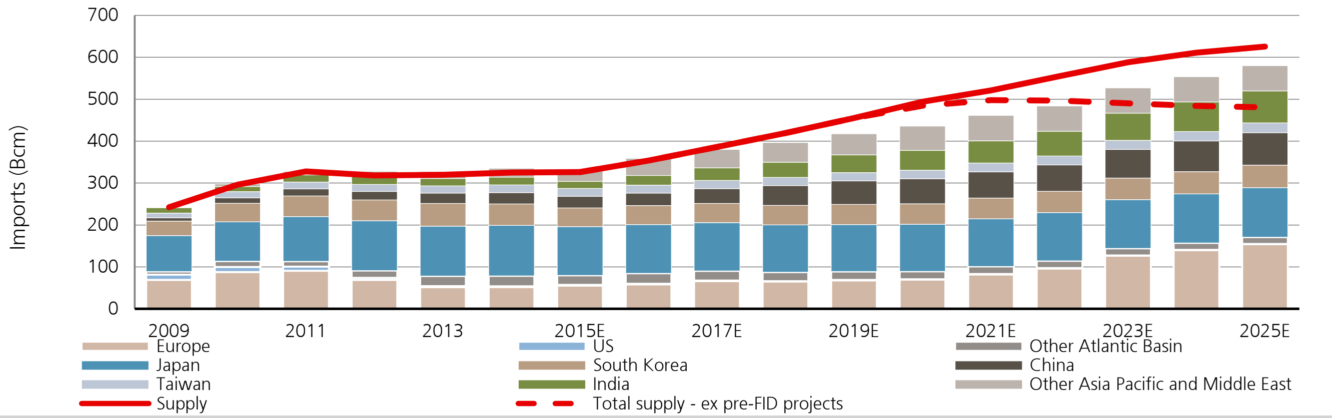
Region/country	Project	Operator	Start-up	Capacity (Mtpa)
Atlantic Basin				
Angola	Angola LNG	Chevron	1Q-2016	5.2
Cameroon	GoFLNG	Perenco	2018	2.4
Russia	Yamal	Novatek	2019	16.5
United States	Sabine Pass 1-2	Cheniere	1Q 2016	9.0
United States	Sabine Pass 3-4	Cheniere	2017	9.0
United States	Sabine Pass 5	Cheniere	2018	4.5
United States	Elba Island Phase 1	Kinder Morgan	2018	1.5
United States	Elba Island Phase 2	Kinder Morgan	2018	1.0
United States	Freeport	JV	2019	9.2
United States	Freeport 2	JV	2020	4.6
United States	Cameron LNG Tr 1-3	Sempra/GDF/Mitusi/Mitsubishi	2018	12.0
United States	Cove Point	Dominion Resources	2019	5.3
United States	Corpus Christi Tr1-2	Cheniere	2019	9.0
				89.2
Asia Pacific				
Malaysia	MLNG T9	Petronas	2017	3.6
Malaysia	PFLNG 1	Petronas	2016	1.2
Malaysia	PFLNG 2	Petronas	2018	1.5
Australia	Gorgon	Chevron	1Q 2016	15
Australia	Ichthys	Inpex	2017	8.4
Australia	Wheatstone	Chevron	2017	8.9
Australia	AP LNG	Origin	End-2015	9.0
Australia	Prelude FLNG	Shell	2017	3.6
				51
				140.2

Source: UBS, Company Data

When do you see LNG S/D re-balancing?

We believe that the market will clear although this may be at the expense of market softness in, for instance, the European market which has significant available regas capacity and liquid hubs. Although the new supply expected is likely to grow well in excess of historic rates of demand growth (4-5%) this comes after 5 years of supply constraint which has seen negligible market expansion. Hence while projected supply growth for 2015-20 is 8-9% cagr it's a lower 4-5% over the 2011-20 period. With the prospect of lower LNG prices driven by lower crude prices and a better supplied spot market alongside emerging new consumption sources the market may clear better than many expect. That being said, there are bound to be periods where the market is impacted by new start-ups and a surplus of cargoes and 1H 2016 could well be the first of these periods.

Figure 28: LNG market S/D balances



Source: UBS

Will approved US LNG export capacity be filled?

Our forecasts assume a relatively high level of utilisation for the US facilities approved, sanctioned and under construction. The tolling structure of the export contracts suggests that off-takers will likely maximise volumes as long as they can make a positive contribution ex this committed cost. However, the fall in oil prices and the consequent fall in oil indexed LNG pricing means that Henry Hub sourced supply from the Gulf Coast is not so obviously competitive. Apparent appetite for alternative price indices now appears to be revealed as merely an appetite for a lower price. Given the very significant US export additions already in train and uncertainty over the oil market and indeed the US gas market it seems unlikely there will be a rush towards further project sanctions.

Figure 29: US LNG projects – under construction and key pre-FID options

	Status	Sponsor	Non-FTA	FERC approved	FID	Target start-up	Forecast start-up	Cost $bn	Capacity
Sabine Pass 1-2	Under Construction	Cheniere	May-11	Apr-12	Jun-12	4Q 2015	1Q 2016	5.6	9.0
Sabine Pass 3-4	Under Construction	Cheniere	May-11	Apr-12	May-13	3Q 2018	2018	5.0	9.0
Sabine Pass 5	Under Construction	Cheniere	Jun-15	Apr-15	Jun-15	2018	2019	3.7	4.5
Sabine Pass 6	FEED	Cheniere	Jun-15	Apr-15		2023		3.7	4.5
Lake Charles	FEED	Southern Union	Aug-13	Dec-15		2023	2020	8.6	15.0
Freeport LNG	Under Construction	Michael Smith	May-13	Jul-14	Nov-14	2018	2019	12.0	13.9
Cameron LNG 1-3	Under Construction	Sempra	Feb-14	Jun-14	Aug-14	1Q18	2018	7.3	12.0
Cameron LNG 4-5	Proposed	Sempra	Feb-14	Jun-14	Aug-14	1Q18	2018	7.3	12.0
Elba Island LNG	FEED	Kinder Morgan				2018	2018	1.9	2.5
Cove Point	Under Construction	Dominion		Sep-14	Oct-14	2019	2019	4.0	5.0
Corpus Christi 1-2	Under Construction	Cheniere	May-15	Dec-14	May-15	2019	2019	11.5	9.0
Corpus Christi 3	FEED	Cheniere	Jun-15	Jan-15		2021			4.5
Corpus Christi 4-5	Proposed	Cheniere				2025			
Magnolia LNG	Proposed	LNG Ltd	U/R	Dec-15		2019			8.0
Golden Pass	FEED	XOM/QP	U/R			2020		10.8	15.6
Jordan Cove	FEED	Veresen	Conditional approval						
Port Arthur	pre-FEED	Sempra							
Alaska LNG	pre-FEED	XOM	Conditional approval						
Capacity (MTPA)									125
Capacity (BCM)									171

Source: UBS, WoodMackenzie, Company Data

US Natural Gas

Have you changed your US natural gas S/D forecast?

- **Following an estimated ~2.6% YoY growth in 2015, we lowered our 2016-17 total US natural gas demand growth forecast to +1.9% YoY (vs. +2.8% prior) in 2016 and +1.5% YoY (vs. +2.2% YoY prior) in 2017**, largely reflecting lower expected demand from the **electric power sector** (largest segment of demand) which we now estimate to be flattish YoY in 2016-17 (vs. +4.7% YoY and +1.4% YoY prior) – see answer to next question below for reason. We still expect steady demand growth from the **industrial sector** (UBSe +3.0% YoY in 2016 and +4.4% YoY in 2017) as well as modest YoY growth from the **transportation** and **commercial sectors** (see Figure 34). Our overall consumption growth rates exclude demand for LNG exports which will commence in 1Q16 and ramp steadily over the next few years from the six projects with 12 Bcfd of send-out capacity that have received both Department of Energy and the more challenging FERC approval.

- **We lowered our 2016 US natural gas supply growth forecast from +3.7% YoY (or +2.8 Bcfd) to +0.5% YoY (or +0.4 Bcfd) as much lower prices reduce drilling activity, but modestly raised our 2017 estimate from +4.0% YoY (or +3.0 Bcfd) to +4.5% YoY (or +3.3 Bcfd) albeit off**

the lower 2016 base. We still expect virtually all of the continued volume growth will come from the Marcellus/Utica; Bentek assumes regional supply growth of +14% YoY (+2.8 Bcfd) in 2016 and +10% YoY (+2.2 Bcfd) in 2017. However, this is a notable reduction from the last few years rate of 4 Bcfd of annual growth, consistent with the reduced capex budgets and growth rates being highlighted by a number of northeast gas producers. Additionally, we expect US production outside of the northeast to moderate from ~1.35 Bcfd YoY in 2015 to flattish in 2016 given the reduction in natural gas and oil drilling activity (e.g. lower associated gas). We expect a resumption of strong production growth in 2017 from the Marcellus/Utica as new pipelines increase takeaway capacity out of the region and more resilient volumes from the rest of the US as higher oil prices and expected drilling activity improve associated gas volumes.

What is the longer term outlook for US gas demand growth? And has this outlook changed with the rise in renewables growth?

- **Over the longer term, we expect demand growth of 12 Bcfd by 2019 to 87 Bcfd from a 75 Bcfd market size in 2015, or ~3.0 Bcfd per annum from 2015-19.** This represents roughly a 3 Bcfd reduction from our prior 2019 forecast which had assumed the natural gas sector could pick up incremental demand from coal plant retirements partly offset by growth in renewables. However, two critical factors have since changed:

  - **While coal plants should continue retiring over the next several years, renewables are likely to take a larger share than we had previously estimated** given solar is now more competitive on a stand-alone basis and the recent US Omnibus spending bill which extended existing tax credits for wind and solar generation facilities for five years should enable increased capacity expansion. From 2010-15, we estimate ~40 GW of coal capacity was retired and, assuming an average ~60% utilization rate, ~24 GW of coal power generation was lost over this time period. On the flip side, we estimate renewables capacity from 2010-15 increased by ~52 GW; however, the lower utilization rate (~20-30%) over this time period enabled just ~14 GW of increased renewables use, leading to a gap of ~10 GW to be filled by gas generation. Over the next five years, we estimate just ~17 GW of coal capacity will be retired but with remaining plants having lower utilization rates of ~55%, leading to a reduction of ~9 GW of coal power generation. Meanwhile, assuming renewables capacity through 2020 grows by ~69 GW and similar utilization rates, we estimate total renewables use for power generation will increase by ~19 GW over the next five years, or a net increase of ~10 GW relative to coal power generation (and thus no gap for gas to fill) – See Figure 30 below;

Figure 30: Coal vs Renewables Power Generation Lost/Added from 2015-20 Relative to 2010-15

	2010-15E	2015-20E
Coal		
Capacity Retired (GW)	-40	-17
Avg Utilization Rate	60%	55%
Coal Power Generation Lost (GW)	-24	-9
Renewables (Wind & Solar)		
Capacity Added (GW)	52	69
Avg Utilization Rate	27%	28%
Renewables Power Generation Added (GW)	14	19
Gap (-) to be Filled by Gas Generation (GW)	-10	10

Source: UBS estimates

- Due to low natural gas prices this in 2015, we estimate gas has already picked up ~4 Bcfd of incremental demand from coal in 2015. Should prices rise above $2.75/MMBtu, we believe the gas market would risk giving back some of that demand to coal.

- Nonetheless, we still expect robust demand growth to come from a combination of LNG exports commencing and ramping up (+10.0 Bcfd by 2020) and the build-out of the chemical industrial base on the Gulf Coast (+2.5 Bcfd by 2020) due to low gas and NGL prices. This is a material step-up in demand growth relative to the 2.1 Bcfd per annum growth from 2009-14.

How much should US production growth slow at current prices?

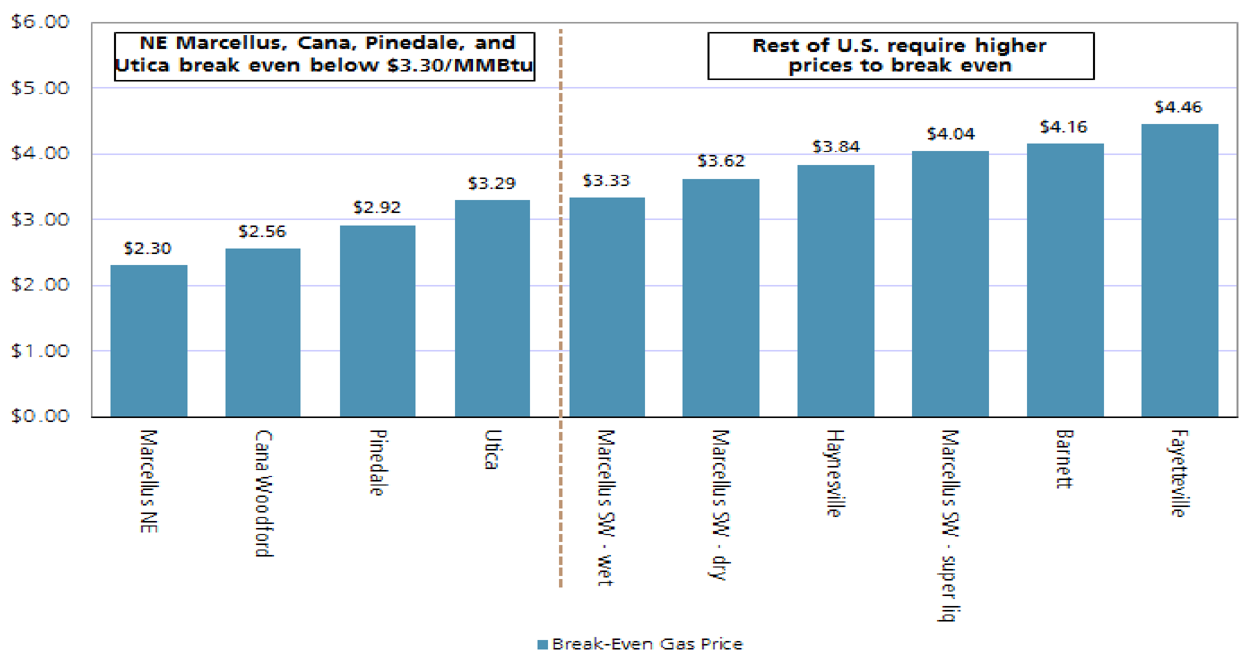
- **Following YoY production growth of 4.2 Bcfd in 2014 and 3.5 Bcfd in 2015, we estimate US natural gas production growth slows dramatically to ~0.4 Bcfd in 2016 from low prices reducing drilling activity and prompting increased shut-ins in the northeast, as well as a slowdown in the buildout of northeast pipeline takeaway capacity until 2017.** These growth rates compare to robust US supply growth in 2014 and 2015 of ~6.3% YoY (or ~4.2 Bcfd) and ~5% YoY (or 3.5 Bcfd), respectively, driven almost entirely by the Marcellus and Utica Shales, which grew ~4 Bcfd per annum over this time period and offset flat-to-declining production in the rest of the U.S. However, with the recent plunge in US gas prices to levels challenging the economics of even low cost Marcellus economics and Marcellus production close to current takeaway capacity with the next large wave of pipeline takeaway expansion in 2017, we expect near-term production growth to be constrained by both a reduced rig count and limited northeast infrastructure takeaway capacity. We forecast US production growth to decelerates next year given slowing growth to ~2.8 Bcfd in the Marcellus/Utica due to infrastructure constraints as well as lower price-driven drilling activity. Despite historically low natural gas prices, we do not expect producing natural gas wells to get shut-in until prices are below lease operating expense (UBSe ~$1/Mcf). However, with expectations of natural gas prices improving in 2017, we forecast production increases ~4.5% YoY (~3.3 Bcfd) in 2017 as northeast infrastructure

constraints are reduced and higher oil prices in 2017 improve associated gas production.

What plays are economic at the current US spot price or futures curve?

- **With the current 2016 natural gas futures curve at ~$2.45/MMBtu, we estimate only parts of the northeast Marcellus in the US is economic at the wellhead based on the breakeven price by play (see Figure 31).** We've assumed a *pre-tax* IRR of ~30% is required to breakeven as well as the cost reductions realized to date this year through efficiency gains and service cost deflation. However, E&Ps tend to invest based on where they believe prices are going rather than where they sit today, particularly for natural gas as short-term pricing is largely driven by near-term weather outlooks. Looking out to 2018-19, the futures curve is ~$3.00/MMBtu but below our normalised (2019+) forecast of ~$3.25/MMBtu…a level at which plays outside of the northeast Marcellus look more compelling such as the Cana-Woodford, Pinedale. Meanwhile, legacy US natural gas plays including the Haynesville, Barnett, and Fayetteville continue to have breakeven prices that are above our long-term normalised natural gas price forecast. *And while certain plays may be economic at the wellhead while natural gas prices are below $2.50/MMBtu, the sharp reduction in cash flows expected in 2016 from lower prices and the expiration of favorable hedges should prompt a material reduction in drilling activity (even in the Marcellus), particularly as gas-weighted E&P balance sheets are stretched with onerous debt/EBITDX levels (many over 4x) at the current futures strip.*

Figure 31: US Breakeven Natural Gas Prices by Play



Source: UBS estimates

Has the emergence of the dry gas Utica reduced the overall supply curve?

- **While initial results from the dry gas Utica have been encouraging and the play adds massive resource potential to the northeast, we believe it is too early to declare it's attractive enough to drive down the US natural gas cost curve**. In addition to only a handful of wells being drilled to date with extended production history, the Utica is ~5,000 feet deeper than the Marcellus with higher downhole pressures and temperatures, causing well costs to currently be 3-4 times higher than Marcellus wells. Notably, management of **Range Resources (Neutral)** believes well costs will ultimately be about twice the Marcellus well costs once Utica transitions into development mode. As such, one could infer that Utica wells would need to have 2x the reserves/well of dry gas southern Marcellus wells (or >35 Bcf) in order to compete for capital. Having said that, industry has proven to be quite adept at moving rapidly up the learning curve in emerging pays and improving play economics, but we believe it is still too premature to conclude that the dry gas Utica drives the US natural gas cost curve down further but concede it bears monitoring. But it should at a minimum considerably extend the period of large low-cost supply exerting a ceiling on natural gas prices.

What is the likely long-term normalised natural gas price?

- **We've lowered our long-term, normalised (2019+) NYMEX natural gas price forecast ($/MMBtu) from $4.00 to $3.25.** We still see a more constructive set-up for long-term demand growth, with the annualized rate of growth increasing from 2.1 Bcfd per annum in 2009-14 to 3.0 Bcfd per annum from 2015-19. And while we previously believed the incremental demand growth required a longer-term price of $4.00/MMBtu, the impressive improvement in non-northeast production demonstrated in 2014 when prices averaged just over $4.00/MMBtu (US natural gas volumes outside the Marcellus/Utica exited 2014 up ~2 Bcfd YoY), US natural gas production outside of the northeast has continued to show resiliency. Notably, despite natural gas prices averaging below $3.00/MMBtu throughout 2015, volumes outside of the Marcellus/Utica have grown on average ~1.3 Bcfd YoY through September…illustrating the robustness of production growth in a <$3.00/MMBtu environment. *Thus, while we still expect volume growth from the Marcellus/Utica slows to ~2 Bcfd YoY in 2018, we believe a normalised price of ~$3.25/MMBtu will incentivize enough growth from higher cost basins to meet the incremental longer-term demand growth.*

Equity Implications

At what oil price do you expect to see capex begin to be increased?

- **We believe the industry is unlikely to materially increase drilling activity until oil prices exceed $60/Bbl and managements are confident that fundamentals have improved enough that prices will stay above those levels.** This oil price selloff has been different than the declines of 2008-9, 2001, 1998-99 in three respects: first, this has been a supply-driven selloff more akin to the 1986 price collapse; second and also similar to 1986, OPEC has abandoned its traditional role of defending price in pursuit of market share, eliminating the safety net of a targeted price band that provides non-OPEC producers some level of longer-term visibility; and third, the duration of this price collapse (and likely the subsequent recovery to normalised levels) is much longer than the more recent price collapses causing much greater stress on balance sheets' financial leverage and managements' efforts to climb down the cost curve. With E&P and Integrated Oil managements really only able to address the third point, managements have made considerable strides at reducing the oil price necessary for Majors to cover capex and the dividend from the >$100/Bbl level in 2014 to an estimated ~$60/Bbl for most Majors by 2017. And the US E&Ps have reduced the oil price needed for economic returns from ~$65/Bbl in 2014 to ~$50/Bbl today. But both the Majors and E&Ps have taken on considerable financial leverage over the last few years, prompting the first wave of incremental cash flow associated with any oil price recovery to go towards re-fortifying balance sheets. In fact, **Apache (Neutral), ConocoPhillips (Neutral),** and **Marathon Oil (Buy)** have all recently stated they would not increase drilling activity levels until WTI exceeded $60/Bbl. And with most Majors needing $60/Bbl to cover both capex and the dividend, it is hard to see that sub-sector of energy increasing activity materially until oil moves north of that threshold.

Appendix – Oil and US natural gas S/D balances

Figure 32: Global oil supply/demand balance (Mb/d)

Demand	2014	1Q15	2Q15	3Q15	4Q15E	2015E	1Q16E	2Q16E	3Q16E	4Q16E	2016E	2017E	2018E	2019E	2020E
OECD Americas	24.1	24.2	24.1	24.7	24.7	24.5	24.2	24.4	24.9	25.0	24.6	24.7	24.7	24.7	24.6
US	*19.4*	*19.6*	*19.5*	*20.0*	*20.0*	*19.8*	*19.6*	*19.8*	*20.1*	*20.2*	*19.9*	*19.9*	*20.0*	*20.0*	*20.0*
OECD Europe	13.4	13.4	13.5	14.1	13.5	13.7	13.5	13.6	14.1	13.5	13.7	13.6	13.5	13.4	13.3
OECD Asia-Pacific	8.2	8.8	7.7	7.8	8.3	8.1	8.6	7.9	8.0	8.3	8.2	8.2	8.2	8.2	8.2
Total OECD	**45.7**	**46.5**	**45.3**	**46.7**	**46.5**	**46.2**	**46.4**	**45.9**	**47.0**	**46.8**	**46.5**	**46.5**	**46.4**	**46.3**	**46.1**
FSU	4.9	4.6	4.9	5.0	4.9	4.9	4.7	4.8	5.0	4.9	4.8	5.0	5.0	5.1	5.2
China	10.3	10.6	10.9	11.0	11.1	10.9	10.9	11.2	11.3	11.5	11.2	11.5	11.9	12.2	12.5
Other Asia	12.0	12.4	12.5	12.3	12.8	12.5	12.9	13.0	12.7	13.1	12.9	13.2	13.6	13.9	14.2
Latin America	7.0	6.8	6.9	6.9	6.9	6.9	6.7	6.9	6.9	6.9	6.9	7.0	7.1	7.2	7.4
Middle East	8.0	7.7	8.3	8.6	8.0	8.2	7.9	8.4	8.9	8.2	8.3	8.6	8.8	9.1	9.3
Africa	4.0	4.1	4.1	4.0	4.1	4.0	4.2	4.2	4.1	4.3	4.2	4.3	4.3	4.4	4.5
Total Non-OECD	**46.9**	**46.7**	**48.3**	**48.4**	**48.7**	**48.0**	**47.9**	**49.2**	**49.6**	**49.6**	**49.1**	**50.2**	**51.4**	**52.6**	**53.7**
TOTAL DEMAND	**92.6**	**93.2**	**93.6**	**95.1**	**95.2**	**94.3**	**94.4**	**95.1**	**96.6**	**96.4**	**95.6**	**96.7**	**97.8**	**98.8**	**99.8**
Supply															
OECD Americas	19.0	19.9	19.5	19.9	19.7	19.8	19.2	18.6	19.2	19.3	19.1	19.4	20.2	20.9	21.5
US	*11.9*	*12.7*	*12.9*	*12.9*	*12.7*	*12.8*	*12.1*	*12.1*	*12.3*	*12.2*	*12.2*	*12.3*	*12.8*	*13.3*	*13.9*
OECD Europe	3.2	3.3	3.4	3.3	3.3	3.4	3.3	3.4	3.3	3.2	3.4	3.4	3.3	3.1	3.2
OECD Asia-Pacific	0.5	0.4	0.4	0.5	0.5	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total OECD	**22.7**	**23.6**	**23.3**	**23.7**	**23.5**	**23.6**	**22.9**	**22.5**	**23.0**	**23.0**	**22.9**	**23.3**	**24.0**	**24.5**	**25.2**
FSU	13.9	14.0	14.0	13.9	13.9	14.0	13.9	13.9	13.9	14.0	13.9	14.1	14.2	14.2	14.0
China	4.3	4.3	4.4	4.4	4.4	4.4	4.3	4.3	4.3	4.3	4.3	4.2	4.1	4.0	4.0
Other Asia	3.5	3.6	3.6	3.5	3.5	3.6	3.5	3.4	3.3	3.3	3.4	3.3	3.2	3.0	2.9
Latin America	4.4	4.6	4.5	4.5	4.6	4.6	4.7	4.6	4.6	4.7	4.6	4.8	4.9	5.2	5.3
Middle East	1.3	1.3	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.3
Africa	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.2	2.2	2.1	2.2
Total Non-OECD	**29.8**	**30.4**	**30.2**	**30.0**	**30.1**	**30.2**	**30.0**	**29.9**	**29.7**	**29.9**	**29.9**	**30.0**	**29.9**	**29.9**	**29.8**
Biofuels	2.2	1.8	2.4	2.6	2.4	2.3	1.9	2.4	2.7	2.4	2.4	2.4	2.4	2.5	2.5
Processing Gains	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.4	2.3	2.3	2.4	2.4	2.4	2.5
Total Non-OPEC	**56.9**	**58.0**	**58.1**	**58.5**	**58.2**	**58.3**	**57.1**	**57.1**	**57.8**	**57.6**	**57.5**	**58.0**	**58.8**	**59.2**	**60.0**
OPEC non-Crude	6.3	6.4	6.5	6.5	6.6	6.5	6.6	6.7	6.8	6.9	6.8	6.8	6.8	6.8	6.9
OPEC Crude Production	*30.3*	*30.5*	*31.5*	*31.7*											
Call on OPEC Crude	29.3	28.8	29.0	30.1	30.3	29.6	30.6	31.3	32.0	31.9	31.4	31.9	32.2	32.8	33.0
TOTAL SUPPLY	**93.6**	**94.9**	**96.1**	**96.7**	**95.2**	**95.7**	**94.4**	**95.1**	**96.6**	**96.4**	**95.6**	**96.7**	**97.8**	**98.8**	**99.8**
OPEC Crude Capacity	**34.3**	**34.2**	**34.2**	**34.1**	**34.0**	**34.1**	**34.3**	**34.5**	**34.8**	**35.1**	**34.7**	**35.3**	**35.5**	**35.7**	**36.0**
OPEC Spare Capacity	*4.0*	*3.8*	*2.7*	*2.3*											
OPEC Spare Capacity - at "call"	5.0	5.5	5.2	4.0	3.7	4.6	3.7	3.2	2.8	3.2	3.3	3.4	3.4	2.9	3.0

Source: IEA, EIA, national energy statistics agencies inc. ANP and NPD, national oil companies, UBS. "OPEC Spare Capacity at call" defined as "call on OPEC crude" less OPEC crude production capacity – i.e. a measure of excess production capacity in the system rather than OPEC's spare capacity at current output levels.

Figure 33: Global oil supply/demand balance (Mb/d, y/y change)

Demand (mb/d change Y-o-Y)	2014	1Q15	2Q15	3Q15	4Q15E	2015E	1Q16E	2Q16E	3Q16E	4Q16E	2016E	2017E	2018E	2019E	2020E
OECD Americas	0.1	0.4	0.4	0.4	0.2	0.3	0.0	0.3	0.2	0.3	0.2	0.1	0.0	0.0	-0.1
US	0.1	0.5	0.5	0.4	0.2	0.4	0.0	0.2	0.1	0.2	0.1	0.0	0.0	0.0	0.0
OECD Europe	-0.2	0.5	0.2	0.4	0.1	0.3	0.1	0.1	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1
OECD Asia-Pacific	-0.2	-0.1	0.0	0.1	-0.1	0.0	-0.1	0.2	0.2	0.0	0.1	0.0	0.0	0.0	0.0
Total OECD	**-0.3**	**0.7**	**0.5**	**0.8**	**0.2**	**0.6**	**0.0**	**0.6**	**0.3**	**0.3**	**0.3**	**-0.1**	**-0.1**	**-0.1**	**-0.2**
FSU	0.2	0.0	0.0	-0.1	-0.1	-0.1	0.1	-0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.1
China	0.2	0.8	0.6	0.6	0.3	0.6	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Other Asia	0.2	0.3	0.4	0.5	0.7	0.5	0.5	0.5	0.4	0.2	0.4	0.3	0.3	0.3	0.3
Latin America	0.2	0.0	-0.1	-0.2	-0.2	-0.1	-0.1	0.0	0.1	0.0	0.0	0.1	0.1	0.1	0.1
Middle East	0.1	-0.1	0.2	0.2	0.2	0.1	0.2	0.1	0.3	0.2	0.2	0.2	0.2	0.2	0.3
Africa	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Total Non-OECD	**1.1**	**1.2**	**1.3**	**1.1**	**1.1**	**1.2**	**1.2**	**0.9**	**1.2**	**0.9**	**1.0**	**1.2**	**1.2**	**1.2**	**1.1**
TOTAL DEMAND	**0.8**	**1.9**	**1.8**	**1.9**	**1.3**	**1.7**	**1.2**	**1.5**	**1.5**	**1.2**	**1.3**	**1.1**	**1.1**	**1.0**	**1.0**
Supply (mb/d change Y-o-Y)	**2014**	**1Q15**	**2Q15**	**3Q15**	**4Q15E**	**2015E**	**1Q16E**	**2Q16E**	**3Q16E**	**4Q16E**	**2016E**	**2017E**	**2018E**	**2019E**	**2020E**
OECD Americas	1.8	1.7	0.7	0.7	0.0	0.8	-0.7	-0.9	-0.7	-0.5	-0.7	0.3	0.8	0.6	0.6
US	1.7	1.6	1.1	0.7	0.0	0.9	-0.6	-0.8	-0.6	-0.4	-0.6	0.1	0.5	0.5	0.6
OECD Europe	0.0	-0.1	0.3	0.3	-0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.1	-0.2	-0.2	0.1
OECD Asia-Pacific	0.0	-0.1	-0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
Total OECD	**1.9**	**1.5**	**0.9**	**1.0**	**-0.1**	**0.9**	**-0.6**	**-0.8**	**-0.7**	**-0.5**	**-0.7**	**0.4**	**0.7**	**0.4**	**0.7**
FSU	0.1	0.1	0.2	0.1	0.0	0.1	-0.1	0.0	0.0	0.1	0.0	0.2	0.1	0.0	-0.2
China	0.0	0.1	0.1	0.2	0.0	0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	0.0
Other Asia	0.0	0.1	0.1	0.1	0.0	0.1	-0.1	-0.2	-0.2	-0.2	-0.2	-0.1	-0.1	-0.2	-0.1
Latin America	0.2	0.4	0.2	0.0	0.0	0.2	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.2
Middle East	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	0.0	0.0	-0.1	0.0	0.0	0.0	0.0
Africa	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	0.1
Total Non-OECD	0.3	0.6	0.6	0.3	-0.1	0.4	-0.4	-0.3	-0.2	-0.2	-0.3	0.1	0.0	-0.1	-0.1
Biofuels	0.2	0.1	0.1	0.0	0.1	0.1	0.1	0.0	0.2	0.0	0.1	0.0	0.0	0.0	0.0
Processing Gains	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0
Total Non-OPEC	**2.4**	**2.2**	**1.5**	**1.3**	**-0.1**	**1.3**	**-0.9**	**-1.1**	**-0.7**	**-0.6**	**-0.8**	**0.6**	**0.8**	**0.4**	**0.7**
OPEC non-Crude	0.2	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.2	0.1	0.0	0.0	0.0
OPEC Crude Production	*-0.2*	*0.5*	*1.4*	*1.2*											
Call on OPEC Crude	-1.8	-0.5	*0.1*	0.4	1.2	0.3	1.8	2.4	1.9	1.5	1.9	0.5	0.3	0.6	0.2
TOTAL SUPPLY	2.4	2.9	3.2	2.7	-0.1	2.2	-0.5	-1.0	-0.2	1.2	-0.1	1.1	1.1	1.0	1.0
OPEC Crude Capacity	-0.5	-0.7	0.0	-0.1	0.2	-0.1	0.0	0.4	0.7	1.1	0.5	0.6	0.2	0.1	0.3
OPEC Spare Capacity - at "call"	1.3	-0.2	-0.1	-0.5	-1.0	-0.4	-1.8	-2.0	-1.2	-0.5	-1.3	0.2	-0.1	-0.4	0.1

Source: IEA, EIA, national energy statistics agencies inc. ANP and NPD, national oil companies, UBS

Figure 34: UBS US Natural Gas Supply/Demand Forecast

											% Growth							CAGR	
	2010	2011	2012	2013	2014	2015E	2016E	2017E	2018E	2019E	13/'12	14/'13	15/'14	16/'15	17/'16	18/'17	19/'18	10-'14	14-'19
Demand Bcf/d																			
Residential	13.1	12.9	11.4	13.4	13.9	12.7	13.28	13.24	13.3	13.3	18.0%	3.9%	-9.0%	4.7%	-0.3%	0.2%	0.2%	1.6%	-1.0%
Commercial	8.5	8.6	7.9	9.0	9.5	9.1	9.37	9.4	9.5	9.6	13.8%	5.2%	-4.0%	2.7%	0.3%	0.9%	0.9%	2.8%	0.1%
Industrial	18.7	19.2	19.8	20.3	20.9	20.5	21.08	22.0	23.7	23.7	2.8%	2.7%	-2.0%	3.0%	4.4%	7.9%	-0.3%	2.8%	2.5%
Electric Power	20.2	20.8	25.0	22.4	22.3	25.9	25.69	25.7	25.9	26.0	-10.1%	-0.5%	16.0%	-0.8%	0.2%	0.5%	0.5%	2.5%	3.1%
Transportation	5.4	5.5	5.8	6.3	6.4	6.8	6.99	7.2	7.4	7.6	8.9%	0.9%	6.0%	3.0%	2.7%	3.0%	3.0%	4.5%	3.5%
Total	65.9	67.0	69.9	71.6	73.0	75.0	76.41	77.6	79.8	80.1	2.4%	2.1%	2.6%	1.9%	1.5%	2.8%	0.5%	2.6%	1.9%
Yr/Yr Growth	*5.1%*	*1.6%*	*4.3%*	*2.4%*	*2.1%*	*2.6%*	*1.9%*	*1.5%*	*2.8%*	*0.5%*									
Supply Bcf/d	2010	2011	2012	2013	2014	2015E	2016E	2017E	2018E	2019E	13/'12	14/'13	15/'14	16/'15	17/'16	18/'17	19/'18	10-'14	14-'19
U.S. Dry Gas Prod. (EIA Estimate)	58.4	62.7	65.8	66.3	70.5	74.0	74.4	77.7	81.6	86.5	0.7%	6.3%	5.0%	0.5%	4.5%	5.0%	6.0%	4.8%	4.2%
Balancing Item	0.3	(0.3)	(0.2)	0.1	(0.0)	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)									
U.S. Dry Gas Prod. (UBS Estimate)	58.7	62.5	65.7	66.4	70.4	73.5	73.9	77.2	81.1	86.0	1.2%	6.1%	4.4%	0.5%	4.5%	5.0%	6.0%	4.7%	4.1%
Canadian Imports	*9.0*	*8.5*	*8.1*	*7.6*	*7.2*	*7.1*	*7.0*	*6.9*	*6.8*	*6.7*	-6.0%	-5.4%	-1.4%	-1.4%	-1.4%	-1.4%	-1.5%	-5.3%	-1.4%
Mexican Imports	*0.1*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	240.4%	33.5%	0.0%	0.0%	0.0%	0.0%	0.0%	-53.3%	0.0%
LNG Imports	*0.9*	*0.7*	*0.4*	*0.2*	*0.1*	*0.1*	*0.0*	*0.0*	*0.0*	*0.0*	-40.8%	-63.0%	0.0%	-99.9%	0.0%	0.0%	0.0%	-44.8%	-73.8%
U.S. Exports	*(2.9)*	*(3.9)*	*(4.4)*	*(4.3)*	*(4.1)*	*(4.7)*	*(5.2)*	*(5.4)*	*(5.6)*	*(5.8)*	-1.3%	-4.6%	14.6%	10.6%	3.8%	3.7%	3.6%	NA	NA
LNG Exports (2016+)	-	-	-	-	-	-	*(0.6)*	*(1.5)*	*(3.0)*	*(6.9)*									
Total U.S. Imports	9.9	9.2	8.5	7.9	7.3	7.2	7.0	6.9	6.8	6.7	-7.5%	-7.0%	-1.4%	-2.5%	-1.4%	-1.4%	-1.5%	-7.4%	-1.6%
Total U.S. Exports	(2.94)	(3.93)	(4.36)	(4.30)	(4.10)	(4.70)	(5.84)	(6.91)	(8.60)	(12.66)	-1.3%	-4.6%	14.6%	10.6%	3.8%	3.7%	3.6%	8.7%	7.2%
U.S. Net Imports (Exports)	7.0	5.3	4.1	3.6	3.2	2.5	1.2	0.0	(1.8)	(5.9)	-14.0%	-10.0%	-21.9%	-52.9%	-99.0%	NA	233.0%	-17.8%	NA
Supplemental Gaseous Fuels	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	65.9	68.0	70.0	70.2	73.8	76.2	75.2	77.4	79.5	80.3	0.3%	5.2%	3.2%	-1.2%	2.9%	2.7%	0.9%	2.9%	1.7%
Implied Inventory Change	(0.0)	1.0	0.1	(1.4)	0.8	1.2	(1.2)	(0.1)	(0.2)	0.1									
Reported Inventory Change	(0.1)	1.0	(0.1)	(1.4)	0.7														

Source: UBS estimates, EIA

Valuation Method and Risk Statement

In history, oil prices have proved consistently unpredictable because so many political, geological, and economic trends and events affect the supply of and demand for oil

Oil prices are extremely volatile in the short, medium and long term, as they are frequently affected by inherently unpredictable events, including natural disasters

Required Disclosures

This report has been prepared by UBS Limited, an affiliate of UBS AG. UBS AG, its subsidiaries, branches and affiliates are referred to herein as UBS.

For information on the ways in which UBS manages conflicts and maintains independence of its research product; historical performance information; and certain additional disclosures concerning UBS research recommendations, please visit www.ubs.com/disclosures. The figures contained in performance charts refer to the past; past performance is not a reliable indicator of future results. Additional information will be made available upon request. UBS Securities Co. Limited is licensed to conduct securities investment consultancy businesses by the China Securities Regulatory Commission. UBS acts or may act as principal in the debt securities (or in related derivatives) that may be the subject of this report.

Analyst Certification: Each research analyst primarily responsible for the content of this research report, in whole or in part, certifies that with respect to each security or issuer that the analyst covered in this report: (1) all of the views expressed accurately reflect his or her personal views about those securities or issuers and were prepared in an independent manner, including with respect to UBS, and (2) no part of his or her compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views expressed by that research analyst in the research report.

UBS Investment Research: Global Equity Rating Definitions

12-Month Rating	Definition	Coverage[1]	IB Services[2]
Buy	FSR is > 6% above the MRA.	48%	36%
Neutral	FSR is between -6% and 6% of the MRA.	39%	28%
Sell	FSR is > 6% below the MRA.	12%	22%
Short-Term Rating	**Definition**	**Coverage[3]**	**IB Services[4]**
Buy	Stock price expected to rise within three months from the time the rating was assigned because of a specific catalyst or event.	<1%	<1%
Sell	Stock price expected to fall within three months from the time the rating was assigned because of a specific catalyst or event.	<1%	<1%

Source: UBS. Rating allocations are as of 31 December 2015.
1:Percentage of companies under coverage globally within the 12-month rating category.
2:Percentage of companies within the 12-month rating category for which investment banking (IB) services were provided within the past 12 months.
3:Percentage of companies under coverage globally within the Short-Term rating category.
4:Percentage of companies within the Short-Term rating category for which investment banking (IB) services were provided within the past 12 months.

KEY DEFINITIONS: Forecast Stock Return (FSR) is defined as expected percentage price appreciation plus gross dividend yield over the next 12 months. **Market Return Assumption (MRA)** is defined as the one-year local market interest rate plus 5% (a proxy for, and not a forecast of, the equity risk premium). **Under Review (UR)** Stocks may be flagged as UR by the analyst, indicating that the stock's price target and/or rating are subject to possible change in the near term, usually in response to an event that may affect the investment case or valuation. **Short-Term Ratings** reflect the expected near-term (up to three months) performance of the stock and do not reflect any change in the fundamental view or investment case. **Equity Price Targets** have an investment horizon of 12 months.

EXCEPTIONS AND SPECIAL CASES: UK and European Investment Fund ratings and definitions are: Buy: Positive on factors such as structure, management, performance record, discount; **Neutral:** Neutral on factors such as structure, management, performance record, discount; **Sell:** Negative on factors such as structure, management, performance record, discount. **Core Banding Exceptions (CBE):** Exceptions to the standard +/-6% bands may be granted by the Investment Review Committee (IRC). Factors considered by the IRC include the stock's volatility and the credit spread of the respective company's debt. As a result, stocks deemed to be very high or low risk may be subject to higher or lower bands as they relate to the rating. When such exceptions apply, they will be identified in the Company Disclosures table in the relevant research piece.

Research analysts contributing to this report who are employed by any non-US affiliate of UBS Securities LLC are not registered/qualified as research analysts with FINRA. Such analysts may not be associated persons of UBS Securities LLC and therefore are not subject to the FINRA restrictions on communications with a subject company, public appearances, and trading securities held by a research analyst account. The name of each affiliate and analyst employed by that affiliate contributing to this report, if any, follows.

UBS Limited: Jon Rigby, CFA; Joseph Head. **UBS Securities LLC:** William A. Featherston.

Company Disclosures

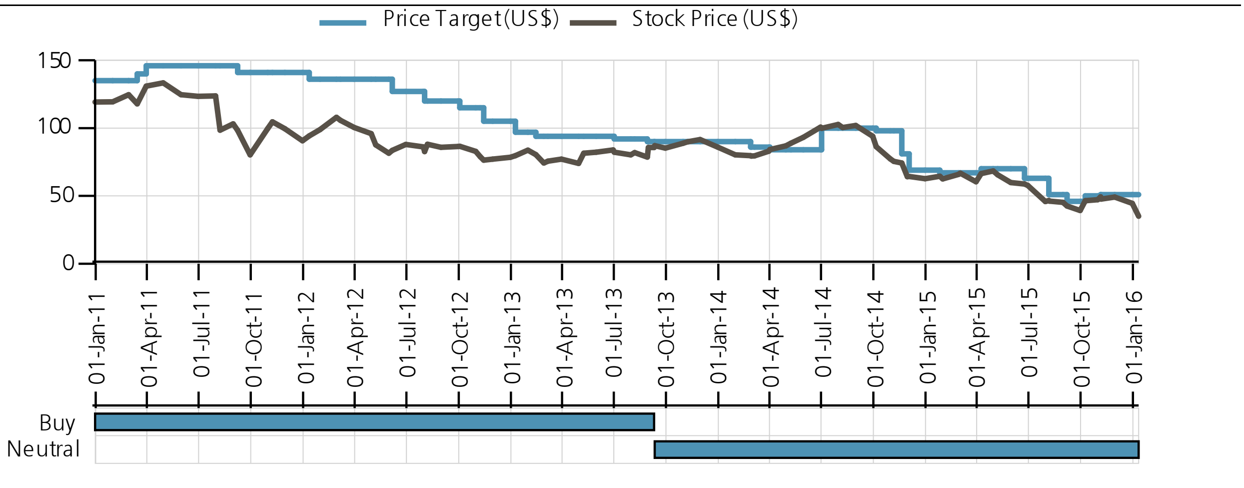
Company Name	Reuters	12-month rating	Short-term rating	Price	Price date
Apache Corporation[6, 7, 16]	APA.N	Neutral	N/A	US$35.06	11 Jan 2016
ConocoPhillips[6, 7, 16]	COP.N	Neutral	N/A	US$41.12	11 Jan 2016
Marathon Oil Corporation[5, 7, 16]	MRO.N	Buy	N/A	US$9.62	11 Jan 2016
Range Resources Corp.[16]	RRC.N	Neutral	N/A	US$24.97	11 Jan 2016

Source: UBS. All prices as of local market close.
Ratings in this table are the most current published ratings prior to this report. They may be more recent than the stock pricing date

5. UBS AG, its affiliates or subsidiaries expect to receive or intend to seek compensation for investment banking services from this company/entity within the next three months.
6. This company/entity is, or within the past 12 months has been, a client of UBS Securities LLC, and non-securities services are being, or have been, provided.
7. Within the past 12 months, UBS Securities LLC and/or its affiliates have received compensation for products and services other than investment banking services from this company/entity.
16. UBS Securities LLC makes a market in the securities and/or ADRs of this company.

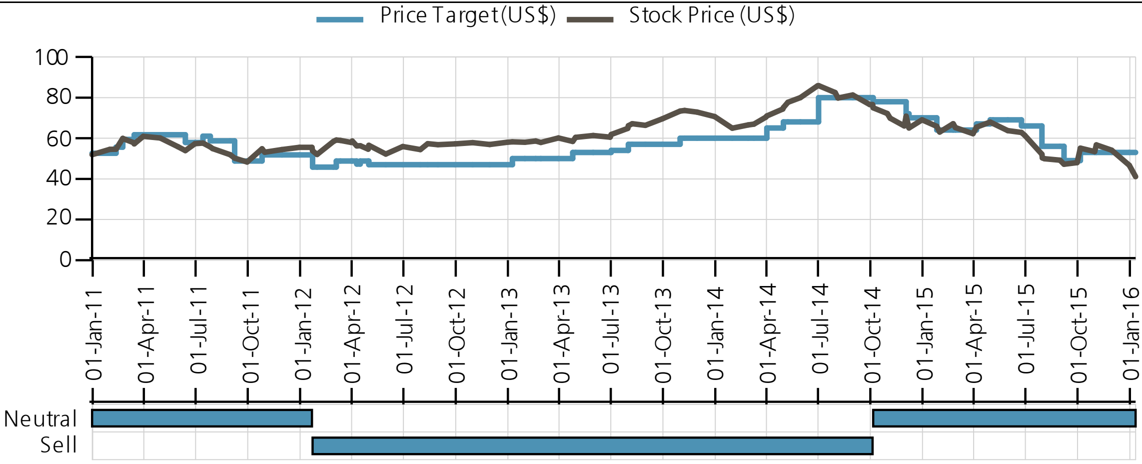
Unless otherwise indicated, please refer to the Valuation and Risk sections within the body of this report. For a complete set of disclosure statements associated with the companies discussed in this report, including information on valuation and risk, please contact UBS Securities LLC, 1285 Avenue of Americas, New York, NY 10019, USA, Attention: Investment Research.

Apache Corporation (US$)



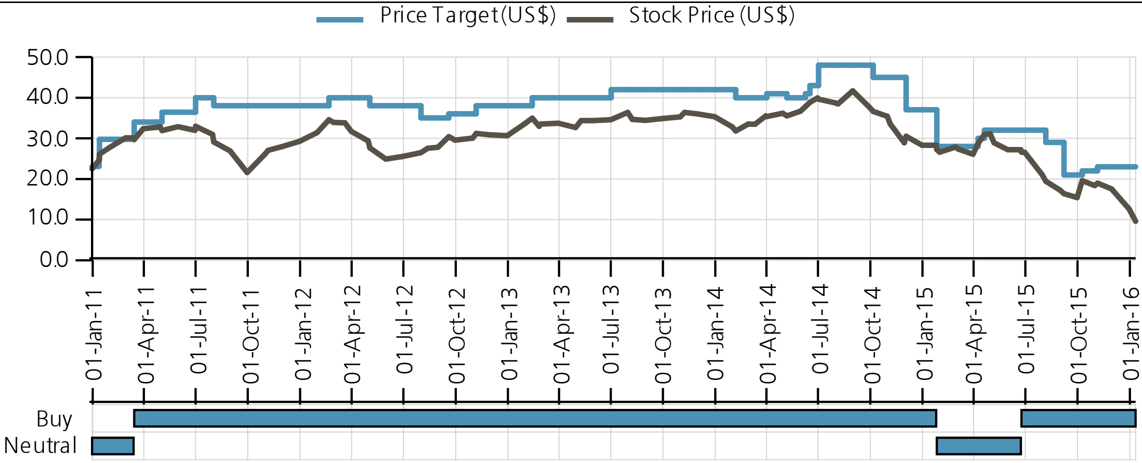
Source: UBS; as of 11 Jan 2016

ConocoPhillips (US$)



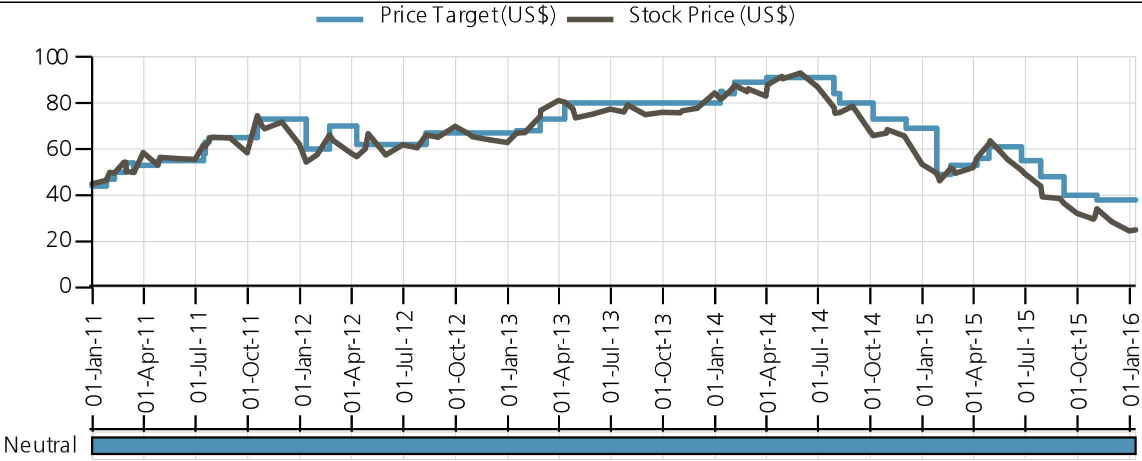
Source: UBS; as of 11 Jan 2016

Marathon Oil Corporation (US$)



Source: UBS; as of 11 Jan 2016

Range Resources Corp. (US$)



Source: UBS; as of 11 Jan 2016

Global Disclaimer

This document has been prepared by UBS Limited, an affiliate of UBS AG. UBS AG, its subsidiaries, branches and affiliates are referred to herein as UBS.

Global Research is provided to our clients through UBS Neo, the UBS Client Portal and UBS.com (each a "System"). It may also be made available through third party vendors and distributed by UBS and/or third parties via e-mail or alternative electronic means. The level and types of services provided by Global Research to a client may vary depending upon various factors such as a client's individual preferences as to the frequency and manner of receiving communications, a client's risk profile and investment focus and perspective (e.g. market wide, sector specific, long-term, short-term, etc.), the size and scope of the overall client relationship with UBS and legal and regulatory constraints.

When you receive Global Research through a System, your access and/or use of such Global Research is subject to this Global Research Disclaimer and to the terms of use governing the applicable System.

When you receive Global Research via a third party vendor, e-mail or other electronic means, your use shall be subject to this Global Research Disclaimer and to UBS's Terms of Use/Disclaimer (http://www.ubs.com/global/en/legalinfo2/disclaimer.html). By accessing and/or using Global Research in this manner, you are indicating that you have read and agree to be bound by our Terms of Use/Disclaimer. In addition, you consent to UBS processing your personal data and using cookies in accordance with our Privacy Statement (http://www.ubs.com/global/en/legalinfo2/privacy.html) and cookie notice (http://www.ubs.com/global/en/homepage/cookies/cookie-management.html).

If you receive Global Research, whether through a System or by any other means, you agree that you shall not copy, revise, amend, create a derivative work, transfer to any third party, or in any way commercially exploit any UBS research provided via Global Research or otherwise, and that you shall not extract data from any research or estimates provided to you via Global Research or otherwise, without the prior written consent of UBS.

For access to all available Global Research on UBS Neo and the Client Portal, please contact your UBS sales representative.

This document is for distribution only as may be permitted by law. It is not directed to, or intended for distribution to or use by, any person or entity who is a citizen or resident of or located in any locality, state, country or other jurisdiction where such distribution, publication, availability or use would be contrary to law or regulation or would subject UBS to any registration or licensing requirement within such jurisdiction. It is published solely for information purposes; it is not an advertisement nor is it a solicitation or an offer to buy or sell any financial instruments or to participate in any particular trading strategy. No representation or warranty, either expressed or implied, is provided in relation to the accuracy, completeness or reliability of the information contained in this document ('the Information'), except with respect to Information concerning UBS. The Information is not intended to be a complete statement or summary of the securities, markets or developments referred to in the document. UBS does not undertake to update or keep current the Information. Any opinions expressed in this document may change without notice and may differ or be contrary to opinions expressed by other business areas or groups of UBS. Any statements contained in this report attributed to a third party represent UBS's interpretation of the data, information and/or opinions provided by that third party either publicly or through a subscription service, and such use and interpretation have not been reviewed by the third party.

Nothing in this document constitutes a representation that any investment strategy or recommendation is suitable or appropriate to an investor's individual circumstances or otherwise constitutes a personal recommendation. Investments involve risks, and investors should exercise prudence and their own judgement in making their investment decisions. The financial instruments described in the document may not be eligible for sale in all jurisdictions or to certain categories of investors. Options, derivative products and futures are not suitable for all investors, and trading in these instruments is considered risky. Mortgage and asset-backed securities may involve a high degree of risk and may be highly volatile in response to fluctuations in interest rates or other market conditions. Foreign currency rates of exchange may adversely affect the value, price or income of any security or related instrument referred to in the document. For investment advice, trade execution or other enquiries, clients should contact their local sales representative.

The value of any investment or income may go down as well as up, and investors may not get back the full (or any) amount invested. Past performance is not necessarily a guide to future performance. Neither UBS nor any of its directors, employees or agents accepts any liability for any loss (including investment loss) or damage arising out of the use of all or any of the Information.

Any prices stated in this document are for information purposes only and do not represent valuations for individual securities or other financial instruments. There is no representation that any transaction can or could have been effected at those prices, and any prices do not necessarily reflect UBS's internal books and records or theoretical model-based valuations and may be based on certain assumptions. Different assumptions by UBS or any other source may yield substantially different results.

This document and the Information are produced by UBS as part of its research function and are provided to you solely for general background information. UBS has no regard to the specific investment objectives, financial situation or particular needs of any specific recipient. In no circumstances may this document or any of the Information be used for any of the following purposes:

(i) valuation or accounting purposes;

(ii) to determine the amounts due or payable, the price or the value of any financial instrument or financial contract; or

(iii) to measure the performance of any financial instrument.

By receiving this document and the Information you will be deemed to represent and warrant to UBS that you will not use this document or any of the Information for any of the above purposes or otherwise rely upon this document or any of the Information.

Research will initiate, update and cease coverage solely at the discretion of UBS Investment Bank Research Management. The analysis contained in this document is based on numerous assumptions. Different assumptions could result in materially different results. The analyst(s) responsible for the preparation of this document may interact with trading desk personnel, sales personnel and other parties for the purpose of gathering, applying and interpreting market information. UBS relies on information barriers to control the flow of information contained in one or more areas within UBS into other areas, units, groups or affiliates of UBS. The compensation of the analyst who prepared this document is determined exclusively by research management and senior management (not including investment banking). Analyst compensation is not based on investment banking revenues; however, compensation may relate to the revenues of UBS Investment Bank as a whole, of which investment banking, sales and trading are a part.

For financial instruments admitted to trading on an EU regulated market: UBS AG, its affiliates or subsidiaries (excluding UBS Securities LLC) acts as a market maker or liquidity provider (in accordance with the interpretation of these terms in the UK) in the financial instruments of the issuer save that where the activity of liquidity provider is carried out in accordance with the definition given to it by the laws and regulations of any other EU jurisdictions, such information is separately disclosed in this document. For financial instruments admitted to trading on a non-EU regulated market: UBS may act as a market maker save that where this activity is carried out in the US in accordance with the definition given to it by the relevant laws and regulations, such activity will be specifically disclosed in this document. UBS may have issued a warrant the value of which is based on one or more of the financial instruments referred to in the document. UBS and its affiliates and employees may have long or short positions, trade as principal and buy and sell in instruments or derivatives identified herein; such transactions or positions may be inconsistent with the opinions expressed in this document.

United Kingdom and the rest of Europe: Except as otherwise specified herein, this material is distributed by UBS Limited to persons who are eligible counterparties or professional clients. UBS Limited is authorised by the Prudential Regulation Authority and regulated by the Financial Conduct Authority and the Prudential Regulation Authority. **France:** Prepared by UBS Limited and distributed by UBS Limited and UBS Securities France S.A. UBS Securities France S.A. is regulated by the ACPR (Autorité de Contrôle Prudentiel et de Résolution) and the Autorité des Marchés Financiers (AMF). Where an analyst of UBS Securities France S.A. has contributed to this document, the document is also deemed to have been prepared by UBS Securities France S.A. **Germany:** Prepared by UBS Limited and distributed by UBS Limited and UBS Deutschland AG. UBS Deutschland AG is regulated by the Bundesanstalt fur Finanzdienstleistungsaufsicht (BaFin). **Spain:** Prepared by UBS Limited and distributed by UBS Limited and UBS Securities España SV, SA. UBS Securities España SV, SA is regulated by the Comisión Nacional del Mercado de Valores (CNMV). **Turkey:** Distributed by UBS Limited. No information in this document is provided for the purpose of offering, marketing and sale by any means of any capital market instruments and services in the Republic of Turkey. Therefore, this document may not be considered as an offer made or to be made to residents of the Republic of Turkey. UBS AG is not licensed by the Turkish Capital Market Board under the provisions of the Capital Market Law (Law No. 6362). Accordingly, neither this document nor any other offering material related to the instruments/services may be utilized in connection with providing any capital market services to persons within the Republic of Turkey without the prior approval of the Capital Market Board. However, according to article 15 (d) (ii) of the Decree No. 32, there is no restriction on the purchase or sale of the securities abroad by residents of the Republic of Turkey. **Poland:** Distributed by UBS Limited (spolka z ograniczona odpowiedzialnoscia) Oddzial w Polsce regulated by the Polish Financial Supervision Authority. Where an analyst of UBS Limited (spolka z ograniczona odpowiedzialnoscia) Oddzial w Polsce has contributed to this

document, the document is also deemed to have been prepared by UBS Limited (spolka z ograniczona odpowiedzialnoscia) Oddzial w Polsce. **Russia:** Prepared and distributed by UBS Bank (OOO). **Switzerland:** Distributed by UBS AG to persons who are institutional investors only. UBS AG is regulated by the Swiss Financial Market Supervisory Authority (FINMA). **Italy:** Prepared by UBS Limited and distributed by UBS Limited and UBS Italia Sim S.p.A. UBS Italia Sim S.p.A. is regulated by the Bank of Italy and by the Commissione Nazionale per le Società e la Borsa (CONSOB). Where an analyst of UBS Italia Sim S.p.A. has contributed to this document, the document is also deemed to have been prepared by UBS Italia Sim S.p.A. **South Africa:** Distributed by UBS South Africa (Pty) Limited (Registration No. 1995/011140/07), an authorised user of the JSE and an authorised Financial Services Provider (FSP 7328). **Israel:** This material is distributed by UBS Limited. UBS Limited is authorised by the Prudential Regulation Authority and regulated by the Financial Conduct Authority and the Prudential Regulation Authority. UBS Securities Israel Ltd is a licensed Investment Marketer that is supervised by the Israel Securities Authority (ISA). UBS Limited and its affiliates incorporated outside Israel are not licensed under the Israeli Advisory Law. UBS Limited is not covered by insurance as required from a licensee under the Israeli Advisory Law. UBS may engage among others in issuance of Financial Assets or in distribution of Financial Assets of other issuers for fees or other benefits. UBS Limited and its affiliates may prefer various Financial Assets to which they have or may have Affiliation (as such term is defined under the Israeli Advisory Law). Nothing in this Material should be considered as investment advice under the Israeli Advisory Law. This Material is being issued only to and/or is directed only at persons who are Eligible Clients within the meaning of the Israeli Advisory Law, and this material must not be relied on or acted upon by any other persons. **Saudi Arabia:** This document has been issued by UBS AG (and/or any of its subsidiaries, branches or affiliates), a public company limited by shares, incorporated in Switzerland with its registered offices at Aeschenvorstadt 1, CH-4051 Basel and Bahnhofstrasse 45, CH-8001 Zurich. This publication has been approved by UBS Saudi Arabia (a subsidiary of UBS AG), a Saudi closed joint stock company incorporated in the Kingdom of Saudi Arabia under commercial register number 1010257812 having its registered office at Tatweer Towers, P.O. Box 75724, Riyadh 11588, Kingdom of Saudi Arabia. UBS Saudi Arabia is authorized and regulated by the Capital Market Authority to conduct securities business under license number 08113-37. **Dubai:** The information distributed by UBS AG Dubai Branch is intended for Professional Clients only and is not for further distribution within the United Arab Emirates. **United States:** Distributed to US persons by either UBS Securities LLC or by UBS Financial Services Inc., subsidiaries of UBS AG; or by a group, subsidiary or affiliate of UBS AG that is not registered as a US broker-dealer (a **'non-US affiliate'**) to major US institutional investors only. UBS Securities LLC or UBS Financial Services Inc. accepts responsibility for the content of a document prepared by another non-US affiliate when distributed to US persons by UBS Securities LLC or UBS Financial Services Inc. All transactions by a US person in the securities mentioned in this document must be effected through UBS Securities LLC or UBS Financial Services Inc., and not through a non-US affiliate. UBS Securities LLC is not acting as a municipal advisor to any municipal entity or obligated person within the meaning of Section 15B of the Securities Exchange Act (the "Municipal Advisor Rule"), and the opinions or views contained herein are not intended to be, and do not constitute, advice within the meaning of the Municipal Advisor Rule. **Canada:** Distributed by UBS Securities Canada Inc., a registered investment dealer in Canada and a Member-Canadian Investor Protection Fund, or by another affiliate of UBS AG that is registered to conduct business in Canada or is otherwise exempt from registration. **Brazil:** Except as otherwise specified herein, this material is prepared by UBS Brasil CCTVM S.A. to persons who are eligible investors residing in Brazil, which are considered to be: (i) financial institutions, (ii) insurance firms and investment capital companies, (iii) supplementary pension entities, (iv) entities that hold financial investments higher than R$300,000.00 and that confirm the status of qualified investors in written, (v) investment funds, (vi) securities portfolio managers and securities consultants duly authorized by Comissão de Valores Mobiliários (CVM), regarding their own investments, and (vii) social security systems created by the Federal Government, States, and Municipalities. **Hong Kong:** Distributed by UBS Securities Asia Limited and/or UBS AG, Hong Kong Branch. **Singapore:** Distributed by UBS Securities Pte. Ltd. [MCI (P) 018/09/2015 and Co. Reg. No.: 198500648C] or UBS AG, Singapore Branch. Please contact UBS Securities Pte. Ltd., an exempt financial adviser under the Singapore Financial Advisers Act (Cap. 110); or UBS AG, Singapore Branch, an exempt financial adviser under the Singapore Financial Advisers Act (Cap. 110) and a wholesale bank licensed under the Singapore Banking Act (Cap. 19) regulated by the Monetary Authority of Singapore, in respect of any matters arising from, or in connection with, the analysis or document. The recipients of this document represent and warrant that they are accredited and institutional investors as defined in the Securities and Futures Act (Cap. 289). **Japan:** Distributed by UBS Securities Japan Co., Ltd. to professional investors (except as otherwise permitted). Where this document has been prepared by UBS Securities Japan Co., Ltd., UBS Securities Japan Co., Ltd. is the author, publisher and distributor of the document. Distributed by UBS AG, Tokyo Branch to Professional Investors (except as otherwise permitted) in relation to foreign exchange and other banking businesses when relevant. **Australia:** Clients of UBS AG: Distributed by UBS AG (Holder of Australian Financial Services License No. 231087). Clients of UBS Securities Australia Ltd: Distributed by UBS Securities Australia Ltd (Holder of Australian Financial Services License No. 231098). Clients of UBS Wealth Management Australia Ltd: Distributed by UBS Wealth Management Australia Ltd (Holder of Australian Financial Services Licence No. 231127). This Document contains general information and/or general advice only and does not constitute personal financial product advice. As such, the Information in this document has been prepared without taking into account any investor's objectives, financial situation or needs, and investors should, before acting on the Information, consider the appropriateness of the Information, having regard to their objectives, financial situation and needs. If the Information contained in this document relates to the acquisition, or potential acquisition of a particular financial product by a 'Retail' client as defined by section 761G of the Corporations Act 2001 where a Product Disclosure Statement would be required, the retail client should obtain and consider the Product Disclosure Statement relating to the product before making any decision about whether to acquire the product. The UBS Securities Australia Limited Financial Services Guide is available at: www.ubs.com/ecs-research-fsg. **New Zealand:** Distributed by UBS New Zealand Ltd. The information and recommendations in this publication are provided for general information purposes only. To the extent that any such information or recommendations constitute financial advice, they do not take into account any person's particular financial situation or goals. We recommend that recipients seek advice specific to their circumstances from their financial advisor. **Korea:** Distributed in Korea by UBS Securities Pte. Ltd., Seoul Branch. This document may have been edited or contributed to from time to time by affiliates of UBS Securities Pte. Ltd., Seoul Branch. **Malaysia:** This material is authorized to be distributed in Malaysia by UBS Securities Malaysia Sdn. Bhd (Capital Markets Services License No.: CMSL/A0063/2007). This material is intended for professional/institutional clients only and not for distribution to any retail clients. **India:** Prepared by UBS Securities India Private Ltd. (Corporate Identity Number U67120MH1996PTC097299) 2/F, 2 North Avenue, Maker Maxity, Bandra Kurla Complex, Bandra (East), Mumbai (India) 400051. Phone: +912261556000. It provides brokerage services bearing SEBI Registration Numbers: NSE (Capital Market Segment): INB230951431, NSE (F&O Segment) INF230951431, NSE (Currency Derivatives Segment) INE230951431, BSE (Capital Market Segment) INB010951437; merchant banking services bearing SEBI Registration Number: INM000010809 and Research Analyst services bearing SEBI Registration Number: INH000001204. UBS AG, its affiliates or subsidiaries may have debt holdings or positions in the subject Indian company/companies. Within the past 12 months, UBS AG, its affiliates or subsidiaries may have received compensation for non-investment banking securities-related services and/or non-securities services from the subject Indian company/companies. The subject company/companies may have been a client/clients of UBS AG, its affiliates or subsidiaries during the 12 months preceding the date of distribution of the research report with respect to investment banking and/or non-investment banking securities-related services and/or non-securities services. With regard to information on associates, please refer to the Annual Report at: http://www.ubs.com/global/en/about_ubs/investor_relations/annualreporting.html

The disclosures contained in research documents produced by UBS Limited shall be governed by and construed in accordance with English law.

UBS