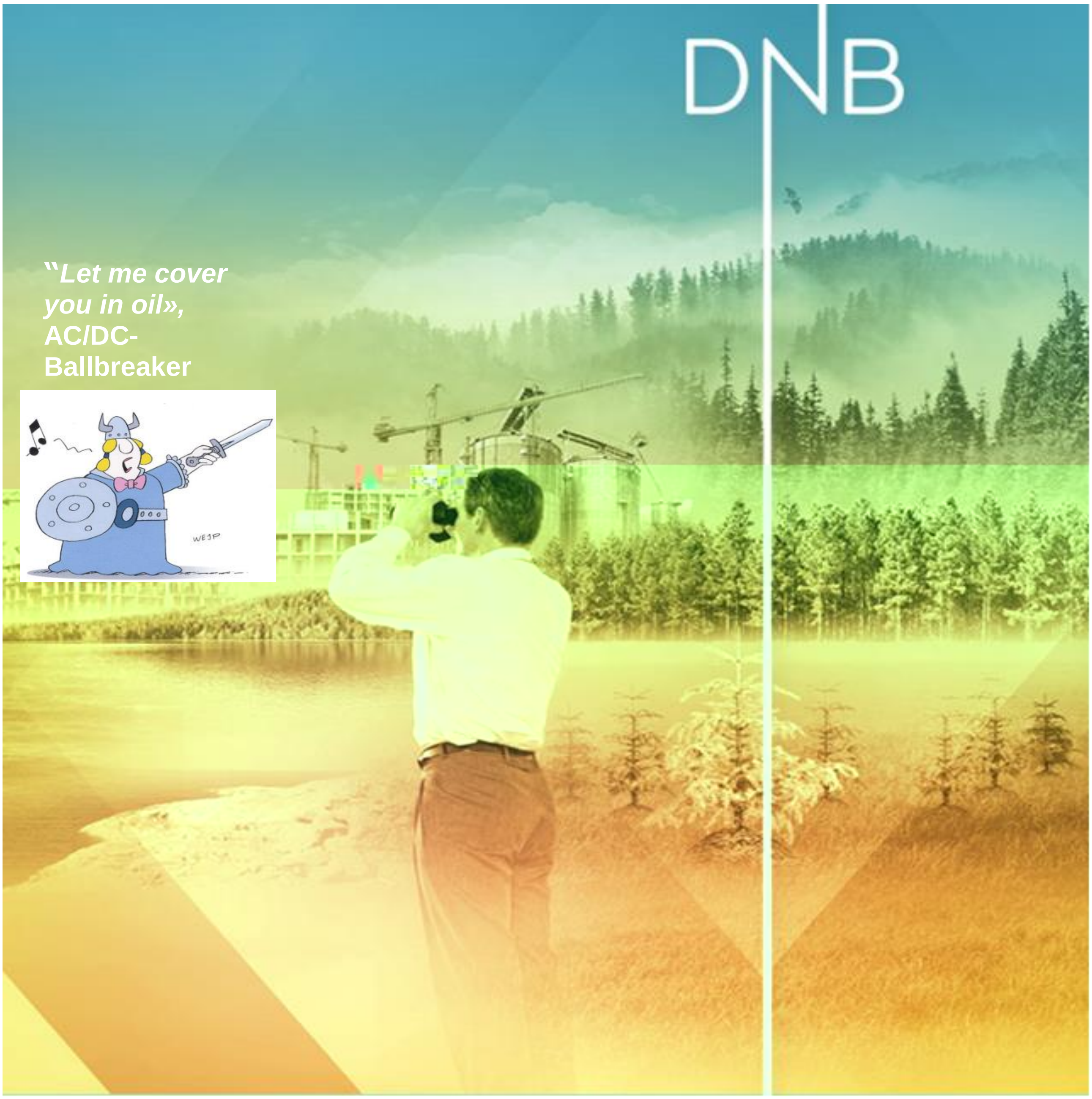
It’s the supply side, stupid

- Which U-shaped recovery? To us it looks like an L

- OPEC General Secretary: *“The reality now is that we cannot have these 100 dollars anymore”*
  - The oil price party is over as the fat lady sings load and clear – *“Let me cover you in oil”…*



Content

1 Overall outlook

We nailed the first half of the 2015-market in our first detailed quarterly forecast for the year, published on January 9. We forecasted an average Brent price of 55 $/b for Q1 and 63 $/b for Q2. The averages became 55.1 $/b and 63.5 $/b. We realize of course that it's pure luck when you hit that close on the levels but sometimes you are lucky…

When it comes to the second half of 2015 we forecasted in January an average price of 74 $/b. That number looks too high now. We are revising our forecast for 2H-2015 down to 58 $/b; 55 $/b for Q3 and 60 $/b for Q4.We are also struggling to find enough bullish arguments to maintain 75 $/b as our price assumption for 2016 and 80 $/b for 2017. We are hence revising down our price forecast for 2016 to 65 $/b and 2017 to 70 $/b. We believe it will be hard for oil prices to rise back above 70 $/b for a while as costs to extract oil are coming down and as global supply looks to outpace demand for longer.

The best argument for higher prices is our expectation of accelerating decline rates in producing oil fields based on the collapse in global E&P spending. Different sources now peg the number of lost jobs in the global oil industry to about 160.000 people as some of the largest oil service providers have sacked 20% of their work force. The large number of project start-ups, which seems to prevail until 2018, could however mask the expected increased decline rates and hence keep the oil price lower for longer. These large numbers of project start-ups are the result of the large investments in the oil industry during the past 5-10 years.

Another bullish argument is of course the current low spare capacity in OPEC. One could argue that the combination of low OPEC spare capacity and increased geopolitical risk is a very powerful bullish combination. There is however now a new type of spare capacity in the market and that is the potential rise in US rig count if prices start to increase.

We are in this report making a change in our oil price forecasting procedure. We are leaving fixed estimates for prices more than three years out in time and are instead launching our estimate of a new "normalized" oil price range in real terms. Everybody knows that to hit a fixed oil price correctly in 2020 is impossible anyway. From 2018 and onwards we believe oil prices will broadly move in a 20 $/b range from 60-80 $/b. During shorter periods prices can of course break out of that range.

We believe cost deflation in the industry translates to more bang for the buck for new oil investments. In our opinion the cost deflation also means that global decline rates may be kept in check at a lower price than what we have seen in recent years. The old 100-120 $/b range that prevailed for nearly four years will no longer be necessary to provide the world with enough oil to cover demand.

When it comes to demand, we believe in a temporarily strong 2015. The strength in 2015 oil demand growth is mainly based on the positive impulse provided by the large deflationary effect of lower prices for the oil consumers. Once the negative inflation disappears from the numbers, the positive demand impulse will probably weaken. During the coming two years we believe the 2015 demand growth of 1.6 million b/d will have faded to 1.2 million b/d in 2016 and 0.9 million b/d in 2017.

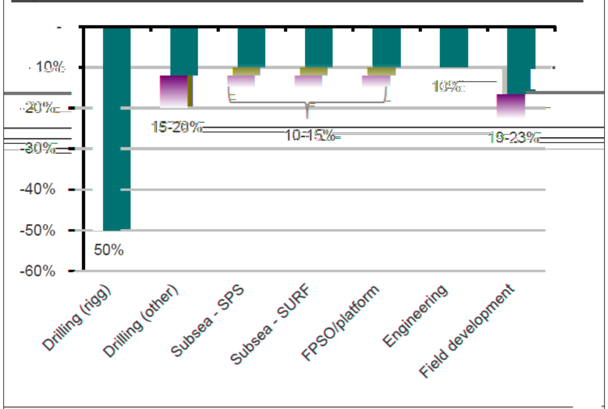
2 Normalized oil price

We have come to the conclusion that it does not make much sense to operate with fixed oil price estimates for more than two-three years into the future. First of all it is hard enough to say anything precise about the oil price level even for next year. In theory one could argue that in the longer term the correct oil price is the 2%-3% most expensive barrels that the market needs to bring from the ground and into production. The price is always set at the margin.

This means that the cost in the oil industry is important for the formation of longer-term prices. Operators in the US shale industry we have met recently are reporting cost deflation of 30%-50% compared with 2014-levels. Half of this is efficiency improvement and half is lower input costs from the service providers.

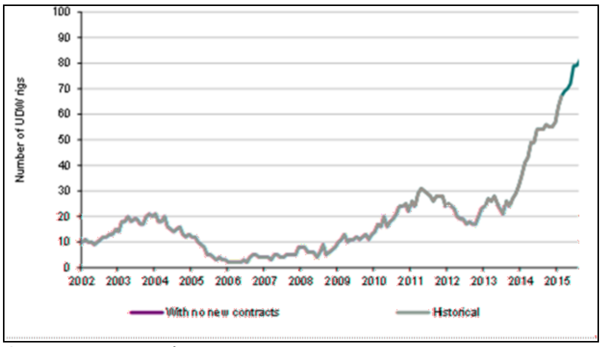
Also in the offshore industry costs are coming down significantly. Maybe not to the same extent as in the US onshore industry so far, but with a lag the costs could probably come down a lot more in the offshore industry as well.

Figure 3: Price deflation in the oil services



Source: Companies, DNB Markets

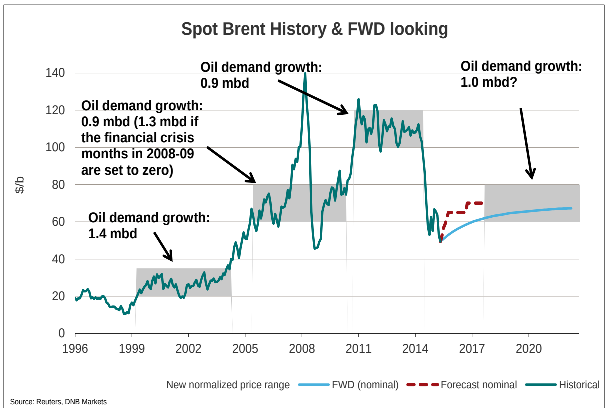
We have for example already seen sizeable reductions in offshore drilling costs, and it will take a long time to see a renewed cost pressure in that industry. The graph below shows the DNB estimate of available Ultra Deepwater Rigs going forward. Standardization in the oil industry will probably also contribute to lower costs in the future.



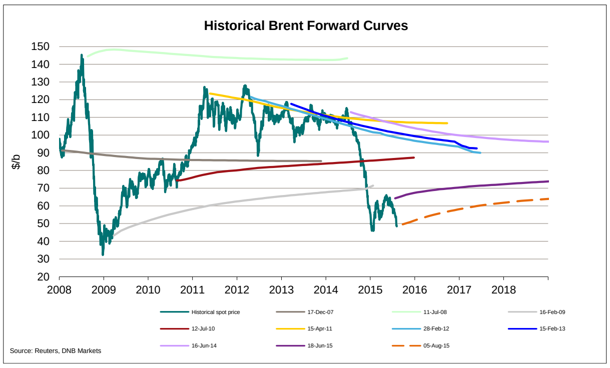
Source: DNB Markets

Based on the above it is reasonable to assume that the “normalized” oil price in the longer term (longer than three years out) should be meaningfully lower than what we have seen during the recent years. Instead of the 100-120 $/b range that we saw in the years 2011-2014, we could see a new range of 60-80 $/b for the longer end of the oil forward curve. This will then be similar to what we saw in the period 2006-2011.

Oil demand growth was not able to keep up at the 100-120 $/b range and oil supply was growing too quickly. The new equilibrium price needs to be lower, but how low is still uncertain. As we wrote at the end of 2014, the market will be in a testing mode through 2015.



Recently we have seen a remarkable drop in the longer term oil prices as can be seen in the graph below.

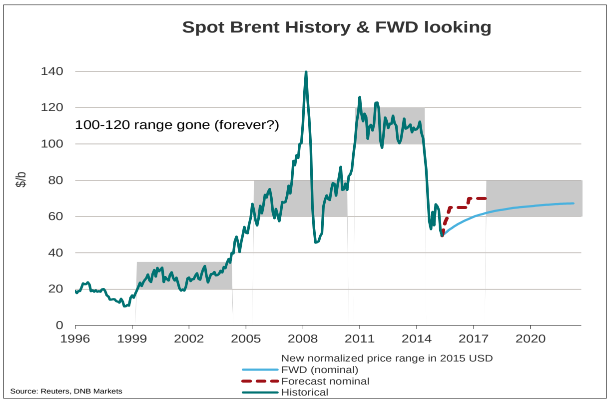


We think it is reasonable that the longer end should be lower as a function of the Iran deal and the lower costs to extract the marginal barrels in the oil industry, but the recent drop has probably also been affected by Mexico's annual oil hedging program which was said to have started much earlier in the year than the norm. According to a recent Bloomberg story, three people with direct knowledge of the matter said Morgan Stanley, Citigroup, JP Morgen and Goldman Sachs were all involved in the program. The recent push lower on contracts for delivery in 2016 and later dates hence may have been somewhat exacerbated by the very large Mexican hedging program.

The spot price for oil will be the long end of the forward curve plus/minus the backwardation/contango in the structure of the forward curve. The structure of the forward curve is highly dependant on the supply/demand-balance. If there is over supply (stock builds), there will be contango and if there is under supply (stock draws) there will be backwardation or at least a flatter forward curve.

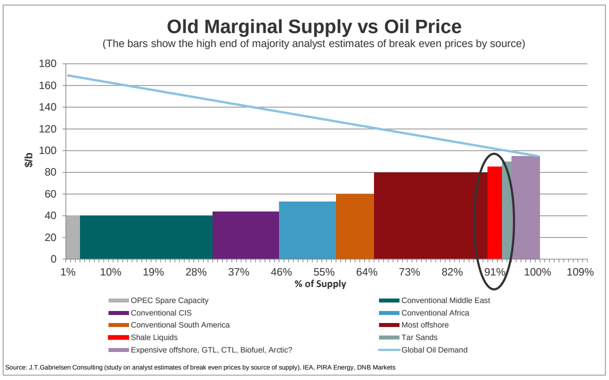
By 2018 we assume the market has found a new equilibrium and that the market may flip between contango/backwardation during a normal year based on inventory changes (changes in supply/demand).

We believe the change to the new oil price forecast procedure will be easier to communicate. Our exact price estimate by quarter for the current year and for the next two years will be in nominal terms, which means comparable to the forward curve. There will be no misunderstandings relating to this forecast and the relation to the forward curve, like we have experienced with prior forecasts where we provided both nominal and real prices. The "normalized" oil price is however to be treated as a real term price.

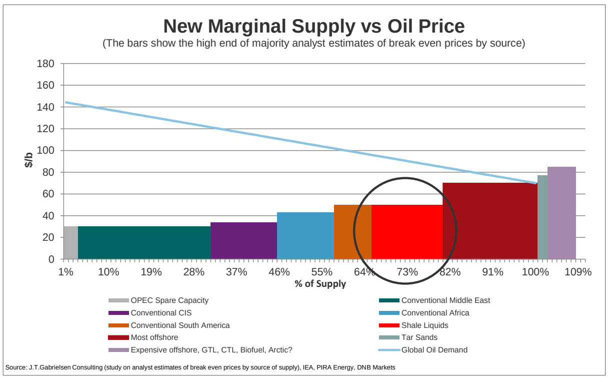


In our "fat lady report" from 2012 we wrote the following: *"For Norway the danger of this new industry* (the US shale industry) *is that it will be a competition to produce our barrels cheaper than what the Americans can do. If the break-even price for shale liquids production in the US drops to let's say a 45-65 $/b range and the Arctic barrels we believe we have in the Barents Sea requires 90 $/b to see the final investment decision, the Norwegian barrels might be competed out of the market. There might not be any need for these barrels."*

We illustrated the above by showing a picture where demand meets supply at the most expensive barrels which then are the price setters in the market. Shale oil was then among the most expensive barrels and contributed in setting the longer-term oil price.



We then showed a graph where the most expensive barrels were being pushed out of the market as shale oil drops in costs and the resource base is estimated to be larger than what most people believed.



This situation has now more or less played out and is the direct reason behind the pain now felt in the Norwegian and Canadian oil industry. It will be painful to be placed at the top of the cost curve when we are in a supply led downturn where the competition is fierce to produce the cheapest barrels. This is one of the key reasons why Statoil and other oil majors are holding back on their investments right now. The whole project portfolio needs to become more robust. Statoil wants to be able to live with oil prices at 50 $/b according to the company's own statements. This means costs will have to come down through the whole value chain, not only in the upstream companies.

This is also why the new "normalized" oil price in our opinion will have to come down to the levels which prevailed before the unsustainably high 100-120 $/b. We believe the 60-80 $/b, which we saw for most of the 2006-2011 period, is probably where the market is heading again.

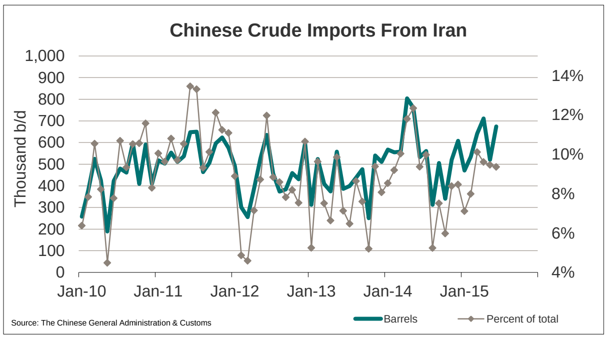
3 Iran – nuclear deal

On July 14 Iran signed a nuclear deal with EU3 (France/Germany/UK) plus USA/Russia/China in order to guarantee the peaceful nature of Iran's nuclear program. The UN Security Council endorsed the so-called Joint Comprehensive Plan of Action (JCPOA) on July 20th.

Under the deal the major powers that signed will not have to take any action for 90 days. But after those 90 days they are required to begin preparations to lift sanctions as soon as the International Atomic Energy Agency (IAEA) submits a report to the UN Security Council verifying that Iran has executed the nuclear-related measures outlined in the agreement. No sanctions relief will be will be implemented until the IAEA submits its report.

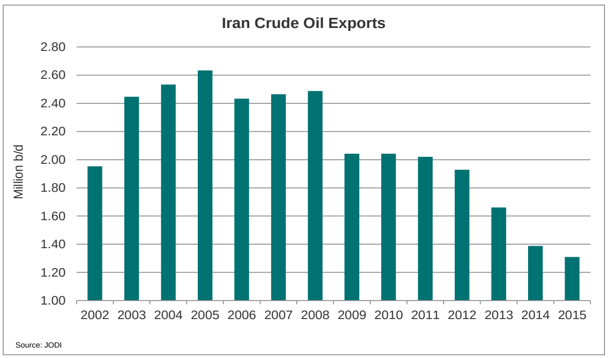
In the US the congress is allowed 60 days from the receipt of the final accord to review and potentially vote to disapprove the deal. Most likely a vote will be held in September. Then, if the deal is not approved by the congress, Obama has 12 days to veto that decision, followed by up to 10 days for congress to override the veto. The congress then needs 2/3rd of the votes. Obama would need at least 34 senators on his side to make sure his potential veto stays intact. It will be interesting to see how this plays out in the coming months. Most likely the opponents of the deal will not be able to secure enough votes to block Obama's veto, but the whole process could drag out in time.

Most likely the full implementation of the deal will not be possible until close to year-end. This means that the bulk of extra Iranian crude oil exports caused by this nuclear deal will be a 2016 issue rather than hit the market during the autumn. We do however believe that there will be some growing "slippage" of Iranian exports to particularly countries like China, India, Turkey, South-Korea, Japan during the rest of 2015. Indian oil imports from Iran for July was for example up 2.4% according to a recent Reuters story. The current US waiver system is likely to formally stay in place but it must be tempting for the largest takers of Iranian crude to raise their imports in anticipation of the end of the sanctions regime. We already see signs of this in the Chinese imports data (customs data), which recently showed that Chinas crude oil imports from Iran rose in June to 674 kbd. This is up from 471 kbd in January.



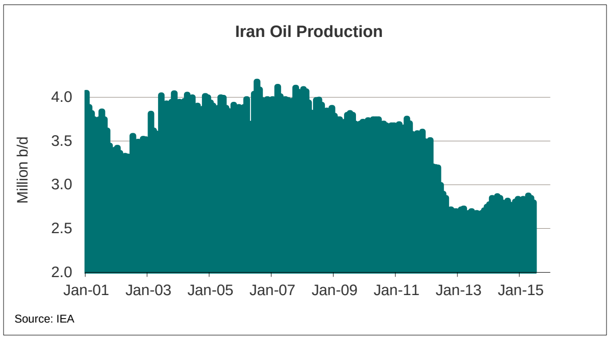
Several different sources estimate Iranian crude and condensate storage on ships to be around 40 million barrels (20 VLCC's). Historically Iran has kept around 5 VLCC's for such storage. Several sources do however believe that the bulk of these barrels are condensates and not normal refinery feedstock crude oil. PIRA Energy writes that the bulk of the 40 million barrels floating storage is mercaptan condensate with high corrosive qualities and awful odor. They hence claim that this condensate will be very hard to sell into the market. Based on the above the reduction of Iranian floating storage may not pose the short-term downside risk many have assumed.

So how much can Iranian production and exports increase going forward? There are many different estimates out there. First of all we should probably start with some historical facts. In 2008 Iran exported almost 2.5 million b/d of crude oil according to JODI data.



So far in 2015 the Iranian crude oil exports have been 1.3 million b/d. If Iran went back to the 2008-level it would hence translate to 1.2 million b/d more exports of crude oil than what we are currently seeing. If we instead compare with the exports that prevailed in 2011, the year before the European oil embargo and the incremental US financial sanctions were implemented, the exports is down 0.7 million b/d.

When it comes to reported crude oil production, Iran produced slightly above 4 million b/d in 2007. Production later drifted down to about 3.7 million b/d by 2009 and stayed at that level until the EU oil embargo, which was implemented in January 2012. Then production quickly fell by 1 million b/d to 2.7 million b/d. We have later seen some "slippage" and Iranian production has averaged 2.8 million b/d so far in 2015.



We believe that at the time the nuclear deal was reached (14th of July) the market expected a deal, which means the price response to the deal was not very large when the deal was published. However, during the latest weeks more Iranian supply has probably been baked into many analysts' and traders' expectations and this has probably, together with weakening data from China and rising OPEC exports, contributed to the drop in Brent prices recently. All the surveys we had read about the issue suggested that the majority of the analysts expected a deal in late June. In our report from May 21 we took in as a base case that a nuclear deal would be reached with Iran. We did however not revise down our price estimates enough, seen in retrospect, even if this view was one of the arguments behind our downgrade in May. We believe much of the price effect of the deal was being priced in from July 1st to July 6th after it became known that the world's second largest independent oil trader (Glencore) had met Iranian officials ahead of a possible deal. During four trading days the spot Brent price fell 7 $/b while the long end of the forward curve fell 4-5 $/b in the same period.

It is difficult to say how many Iranian barrels the market is now discounting as there are many opinions on how quickly physical volume will return to the market and how many barrels we are going to see. Iran's oil minister Bijan Namdar Zanganeh recently stated that Iran wants to pump almost 4 million b/d within seven months after sanctions are lifted and 4.7 million b/d as soon as possible after that.

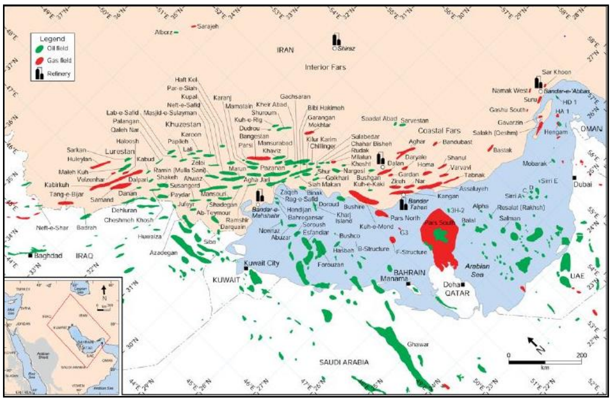
Zanganeh also stated that *"such an increase may cause oil prices to fall, but that does not mean we won't enter our oil into the market".* Other highly interesting statements from Zanganeh are the following: *"Countries that sold more oil and took market share from sanctions-bound Iran will have to adjust as the country restores its output and exports to historical levels. Those who are responsible for protecting prices are those who have filled our share before and used it. Our only responsibility here is attaining our lost share of the market, not protecting prices."*

We think that sanctions will be lifted by year-end and that Iran should be able to reach back to about 3.5 million b/d by 1H-2016 from the current level of 2.8 million b/d in output. These extra barrels should be going to exports, which should hence increase exports from today's 1.3 million b/d to about 2 million b/d by next summer. In order to take the next step and reach back to 4 million b/d in production and 2.5 million b/d in exports we believe it will be necessary to invest heavily in the Iranian oil industry. Those investments will most likely be coming in our view.

Iran has already been preparing for sanctions relief for a while and is planning a new contract structure to secure 100 million dollars in new investments from foreign oil companies. At a recent business conference in Vienna the Iranian Industry Minister stated that Iran needs about 100 billion USD to bring the country's oil industry back to the level where it was five years ago. According to the global oil consultancy FGE, Iran will be able to access 80-150 billion USD in cash from frozen overseas accounts once the financial sanctions are lifted.

According to Afraz Advisers, which is an independent company offering strategic insights and advice on the Iranian oil and gas market, the National Iranian Oil Company (NIOC) has announced 50 projects available for national and international participation once sanctions are removed.

There is nothing wrong with the resource base in Iran. According to BP stats Iran holds the fourth largest oil resources in the world at 158 billion barrels, only beaten by Saudi Arabia, Venezuela and Canada. It should hence be possible to produce a lot more than today if western technology is utilized and if money is spent. In addition the Iranian barrels should be mainly lower on the cost scale than barrels from competing countries like Canada and Brazil and the disruption risks are much smaller than in Iraq where violence has exploded in recent years. If sanctions really end up being removed we thus believe Iran will be able to attract a lot of investments to its oil industry in coming years.



Source: Afraz Advisers Ltd.

The new Iranian Petroleum Contracts (IPC's) are designed to also attract smaller to medium sized companies. International oil companies (IOC's) will be given contract terms that are more attractive than those found in Iraq and Kurdistan today, according to Afraz Advisers.

In the new IPC's the IOC's will be the operator of a field for 20 years, overseeing both the development and production phase. Even better terms will be offered to IOC's who engage in exploration and development activities in challenging and unconventional fields.

The new IPC's also encourages IOC's to partner with established Iranian oil and gas companies. Both the local partner and the IOC are however required to fully finance the project. The key backdrop to why such partnerships will be offered even better terms are due to the gaps in local technical expertise with respect to:

- Advanced IOR/EOR technologies
- The latest drilling technologies
- Technologies for heavy oil, deep reservoirs and sour gas fields
- Reservoir management and optimization

The new IPC's offers a number of significant advantages according to Afraz Advisers. Among others:

- Reduced CAPEX risk
- Foreign operatorship
- Longer contracts (20-25 years)
- Payment formula that rewards higher production
- Individual terms for each block
- Increased flexibility in recovery of investment costs

4 Saudi reorganization

The reorganization in Saudi Arabia started in January when the former king Abdullah died after having ruled the kingdom for 20 years. His first ten years he was the de facto ruler after King Fahd suffered a stroke in 1995 and when Fahd died in 2005 Abdullah was formally appointed king of Saudi Arabia.

Abdullah's legacy was that he initiated some reforms in the country; like promoting women's rights, limiting the religious establishment's power base and building new universities. Abdullah will however probably not be remembered as a great reformer as still the royal family holds all the real power in the country and ordinary citizens still have very limited opportunities to achieve political influence.

One could also ask if much is achieved for women's rights when women still are not allowed to drive cars in Saudi Arabia. For someone coming from a western country this law almost seems like a cartoon joke and of course has no place in the 21st century in any country.

During Abdullah's reign the close relationship with the US cooled down, particularly the latest 3-4 years. King Abdullah was for example reportedly furious over the Obama administration's reluctance to support Mubarak in Egypt. He was very much against the nuclear negotiations and a deal with Iran and also would like the US to have supported Assad in Syria.

The new King Salman succeeded Abdullah on January 23rd. The new king is 82 years old and is the oldest surviving son of Ibn Saud who founded Saudi Arabia in 1932. Immediately at his appointment the new king appointed his half-brother Muqrin as the new crown price and his nephew Muhammad bin-Nayef as the deputy crown prince. Muqrin was already in January described as having a weak power base as his family branch is not among the strongest ones. It was however not seen as a large surprise that he became the crown price in January. It was more of a surprise that the 55-year old Muhammed bin-Nayef was appointed crown prince. He is the first grandson of Ibn Saud that is set to inherit the throne.

During the last week of April however, more dramatical changes to the power distribution in Saudi took place. Crown prince Muqrin was stripped of his title and instead the former deputy crown prince bin-Nayef was appointed the new crown prince. It is apparently highly unusual that a king replaces a crown prince that was appointed by a former king. It was even stated in the original appointment of Muqrin as crown price by Abdullah that this decision could not be overturned. King Salman however reportedly stated that Muqrin left his post upon his own request.

The new crown prince, Muhammad bin-Nayef has a reputation as a good leader and as such that move was not totally unexpected. More of a shock came from the fact that king Salman in the same shuffle appointed his around 30-year old son Muhammad bin-

Salman as the new deputy crown prince. Bin-Salman was already appointed defense minister (apparently he is the youngest defense minister in the world) and he is also the head of the new Economic council which replaced the old Petroleum council. There are now even rumors inside Saudi Arabia that bin-Salman could soon replace the current oil minister Al-naimi.

Former kings have appointed non-royals to oil ministers to avoid the notion that one family branch controls the country’s main source of revenues, but this may now change. The recent reorganization of Saudi Aramco could be a step in the direction of setting the stage for the first royal oil minister. Oil minister or not, bin-Salman will be one of the key decision makers in the Saudi oil policies going forward, as he is already heading up the new Economic council.

Some political analysts argue that the new and aggressive militaristic foreign policy (described as the Salman-doctrine) must be seen as Salman’s attempt to consolidate power for his own family branch. The attack on the Houti rebels in Yemen could be an effort to lift the popularity of the new deputy crown prince bin-Salman. In the Saudi media the new deputy crown prince is pictured as a decisive military commander and reportedly the attacks in Syria are popular among the common Saudi Arabian citizen.

After these recent moves by king Salman one could argue that a “palace coup” has taken place in Saudi Arabia. King Salman, the former King Fahd and the former crown prince Nayef were all full brothers from the most powerful branch of the Saudi Royal family; the Sudayri clan. The other former kings and prices have all been half-brothers. Both the new crown prince and the new deputy crown prince are from the Sudayri clan, while two of the former king Abdullah’s sons were stripped from their positions as governors of Riyadh and Mekka respectively. The only son of Abdullah which remains in a powerful position is currently the 62-year old Mitab bin-Abdullah who remains the head of the Saudi Arabian National Guard. The former king Abdullah probably wanted Mitab bin-Abdullah to have become a future ruler of Saudi Arabia, according to Stig Stenslie, the expert on the Saudi Royal family. According to him, the new appointments are creating increased risk for unrest in Saudi Arabia as rivalry is set to increase between the most powerful family branches.

If the new king wanted to install peace and harmony in the royal family he would probably have appointed Mitab bin-Abdullah as the deputy crown prince instead of his own son. The new young deputy crown price will find it hard to become a respected and unifying figure in the royal family. All former kings have promoted their own sons to positions of wealth and power but still within certain limits. Age and experience are supposed to count and by appointing his own young son as the deputy crown prince, king Salman is bypassing a number of princes who are older and more experienced.

It is worth noting that in 1964, king Saud was stripped from his title by his own brothers, exactly because he tried to gather too much power in the hands of his own sons. According to the Saudi Arabian constitution all of Ibn Saud’s about 200 grandsons are qualified to become king. Based on the above we would subscribe to an interpretation of increased internal risk in Saudi Arabia as a result of the shuffle of powerful positions in the country.

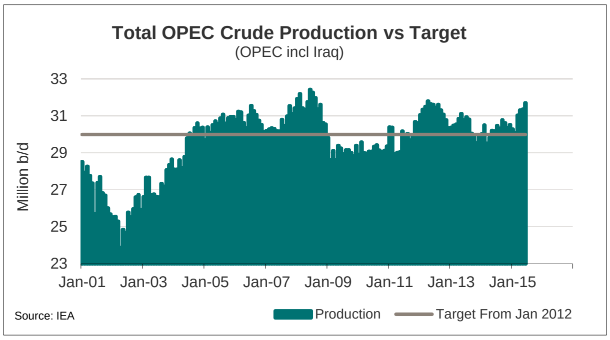
5 OPEC

OPEC decided (as expected) on June 5 to maintain the market share policy it adopted on November 27.

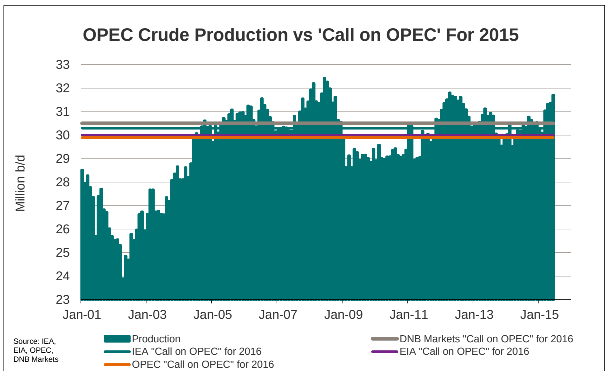
In our “fat lady report” from 2012 we wrote the following about OPEC:
“Since Saudi Arabia may evaluate the oil price in a longer time perspective than the other cartel members it could be beneficial for the kingdom to repeat the 1986-91 exercise from time to time. The kingdom would then achieve protection of longer-term oil demand and make the transition period to another world energy mix longer. In addition it would “shoot down” non-OPEC projects like shale liquids in the US. Hence an oil price of 50 $/b for a couple of years may not be all that bad for Saudi Arabia if thinking in a long term perspective. It would protect the kingdom’s long-term market share.”

We think the same arguments will prevail also going forward. Saudi Arabia has decided to follow the market share policy and to not repeat the mistakes of the 1980’s where they first cut production to protect prices. In this play it will be important not to change policy too quickly. If the market share strategy is left too early the risk would be that what is so far achieved of CAPEX cuts in the global oil industry reverses and then more supply hits the market earlier than what the Saudi’s would prefer. If the oil price can be kept low enough for another year or two, the longer-term benefit of the current policy will be larger than if the strategy were to be left already in December.

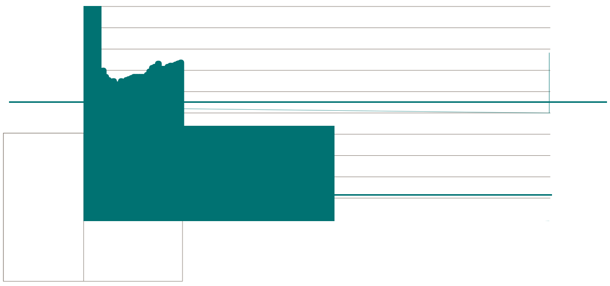
The latest known OPEC production level is 31.7 million b/d according to the latest data from IEA.



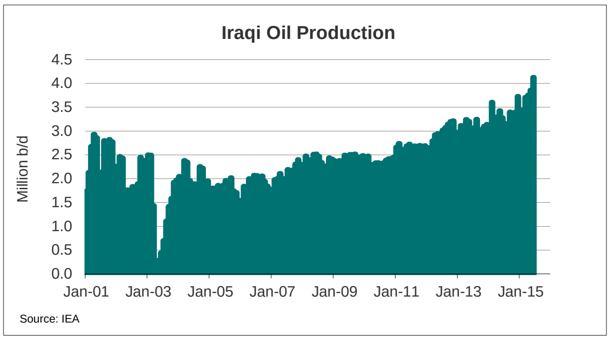
The production target was left unchanged at 30 million b/d in the June meeting. The problem for oil prices is that 31.7 million b/d is much higher than the “call on OPEC” for next year which we estimate to be 30.5 million b/d.



This means that even without Iran returning to the market and with Libya only producing 0.4 million b/d, OPEC will produce 1.2 million b/d more than the market requires next year. We have already stated earlier in the report that we expect Iran to increase its production by 0.7 million b/d by next summer and Libya at only 0.4 million b/d is at best neutral. You can’t lose what you don’t have to put it that way.

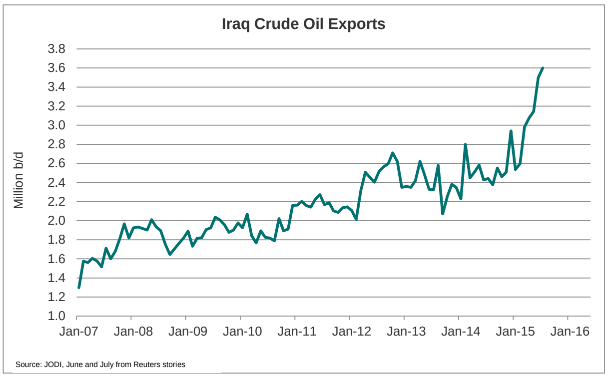


The bulls will have to hope for a collapse in Iraqi oil production that has increased to a record 4.1 million b/d.



Fresh reports from Iraqi crude oil exports do however suggest that new records were set for July. Southern Iraqi exports, which reached a record 3.02 million b/d in June, were even higher in July at 3.06 million b/d. It seems the Iraqi decision to split the Basrah Light crude stream into two grades is paying off with respect to increased volume. Iraq's SOMO is now offering the new Basrah Heavy grade which is split out of the old Basrah Light stream. This has allowed some companies to increase production.

Independent KRG northern exports averaged 516 kbd in July while SOMO exported only 71 kbd from the north of Iraq. This means that total Iraqi crude exports was about 3.6 million b/d in July, which was a new record.



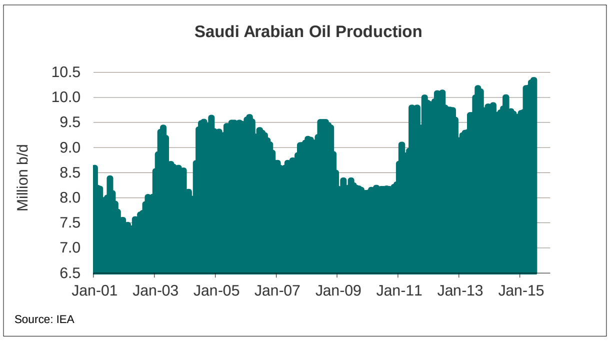
Another option for the bulls would be to hope for a Saudi production cut to make room for Iran in the next OPEC meeting now scheduled for December 4th. In our opinion this will not happen. As described above, we believe it would be premature for Saudi Arabia to leave its market share strategy already in 2015.

Yes, the Saudi's have spent a lot of money this year as they have not cut their budget but instead drawn down their foreign reserves by about 65 billion USD and borrowed 4 billion USD through a bond issue (the first in eight years). Saudi Arabia is reportedly planning to raise another 27 billion dollars in the bond market this year. According to the FT, the Saudis require an oil price of 105 $/b to balance the budget, but the budget this year is set to show a deficit of 38.6 billion USD compared with a 54.9 billion USD surplus in 2013. A lot of the money spent in 2015 is however a one-off as public employees were awarded three months' salary in connection with King Salman stepping into office and there is still about 670 billion USD left in the foreign reserves.

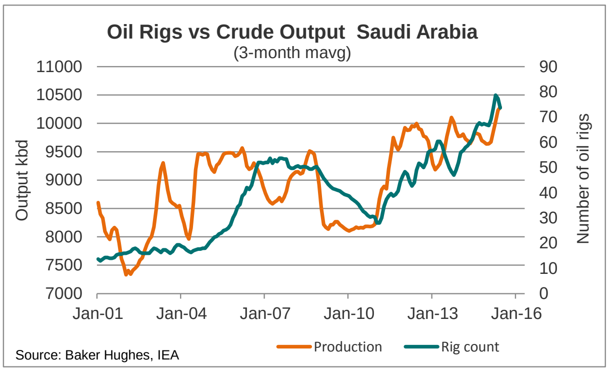
If the Saudis should choose to cut production in the next meeting to get the oil price up, then the risk would be that global oil investments and activity again increases which would mean that "most of the work" done since November last year might have been in vain.

Why take that risk? Why not instead let the market ride this out and make sure that global oil investments and activity suffers for at least a couple of years in order to make sure that many high cost producers (Deepwater and Canadian oil sands) are shut out of the market for an extended period so that Saudi instead can maintain its market share?

Saudi Arabia has recently increased production to record high levels. According to the IEA database Saudi produced 10.35 million b/d in June. This is in fact up a large 0.6 million b/d from Jan/Feb-levels. In the OPEC report for July, the so-called direct reported production from Saudi itself states June production as high as 10.56 million b/d.



The increased number of oilrigs in Saudi Arabia does not suggest that the Kingdom is planning to cut down on its output.



And historically there has been a decent correlation between the rig count and production, which can be seen in the graph above.

A point to be made is also the direct crude burn in Saudi Arabia which tend to correlate quite well with the country's output in recent years, except for the summer of 2011 when the Saudis had to make up for the Arab Spring shortfall from Libya (We also had a coordinated IEA emergency stock release that summer). The last number we have for Saudi direct crude burn is now from May (from the JODI-data posted in July). The Saudis then burned 677 kbd of crude mainly for air-conditioning. This was up a large 319 kbd from April, but normally the direct crude burn continues to increase all the way into July/August.

Last year direct crude burn in Saudi Arabia peaked in July at 899 kbd which was a record amount. As such we could be in for another about 200 kbd domestic deman

One could argue that if Saudi Arabia is serious about its market share policy it should try to use up its spare capacity. The country itself claims to have a capacity to produce 12.5 million b/d. The IEA estimates that Saudi Arabia's production capacity is 12.3 million b/d. The IEA-definition of capacity is the level of production that can be reached within 90 days and sustained for an extended period. If really the capacity is 12.3 million b/d, then Saudi has about 2 million b/d as spare capacity.

This spare capacity should be used to maintain/capture market share going forward, if the capacity is really there. We do however question if there is really 2 million b/d of spare capacity left, but if it is really there, we would expect to see even higher production from Saudi Arabia going forward.

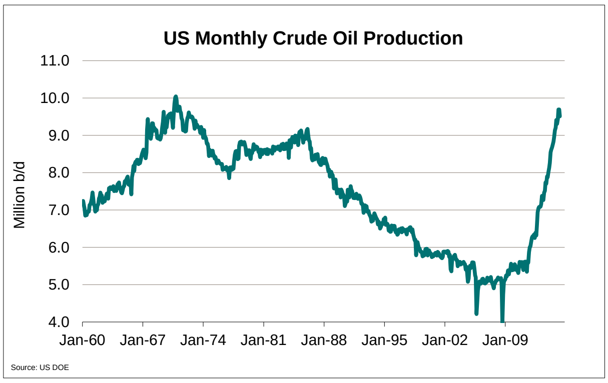
What really counts in Saudi Arabia's favor in the longer term is the fact that in 2014 Saudi Aramco discovered eight new oil& gas fields. This is the most in Saudi Aramco's history, so people believing that all the resources in Saudi Arabia are already mapped have to think again. Saudi Aramco also completed a number of offshore wells in the Red Sea in order to achieve a deeper understanding of the hydrocarbon systems and potential resources in that region.

Source: Saudi Aramco

The new Exploration Explorer System that Saudi Aramco launched in 2014, is reportedly changing the way the Saudis deal with oil & gas prospects. Use of the system saves time, effort and resources and allows better cooperation between geologists, geophysicists and other exploration support personnel. We should hence expect more discoveries from the Saudis in the coming years, not less.

6 US oil production

US crude oil production reached 9.7 million b/d in March but was recently reported at 9.5 million b/d for May. The production represents a massive and incredible increase of 3.2 million b/d since August 2012, when we issued our “fat lady report”. We claimed in that report that the US shale oil industry was a revolution and a game changer that would send global oil prices lower and that 2012 would be the year in the current decade with the highest oil prices. We still stand by that statement.



Now the key question everybody asks is if US oil production will start falling and if so how much production will suffer? If US oil production growth fades from an increase of 1.6 million b/d in 2014 to no growth in 2016 it would be the key contribution towards a rebalancing of the global supply-demand balance.

It would however not solve the whole over supply issue due to the fact that OPEC is producing close to record high volumes, but it would nonetheless help a lot for the balance. It would be particularly helpful if oil production growth were to turn negative of course. We will focus on the US shale industry, even though one will not get the whole picture of US oil production correct even if one get the shale industry correct. This is due to the fact that the large investments in the offshore US GOM during the past 5-10 years have started to bear some fruit. During the past 18 months the crude oil production in the US GOM is up more than 0.3 million b/d and there are more project startups in the pipeline. In the Goldman Sachs Top 420 projects to change the world report there are 20 US offshore projects with a total peak production capacity of 2.3 million b/d. But now back to the shale industry, which will be even more important for the global balance than the US GOM.

Many analysts and investors have been and still are highly skeptical to the US shale industry and its ability to generate enough cash to cover the cost and a decent return. The key argument against the industry is that the growth has been to a large extent financed by increasing debt and with the collapse in oil prices several companies are struggling with the cash flow as a larger share of the revenues must go to service this debt. If we look at the ten largest pure shale players it looks as if on average about 10% of the revenues in 2015 will be used to service debt. Companies like Oasis, Chesapeake, Continental Resources and Whiting all looks to be above 10%.

Lifting costs in $/b (incl. G&A costs & County/State tax)	15										
Interest rate:	5%										
WTI price ($/b)	50										
NGL's price as percentage of crude price:	35%										
Company name:	**EOG**	**Chesapeake**	**Pioneer**	**Whiting**	**Continental**	**Concho**	**Noble**	**Cimarex**	**Crescent**	**Oasis**	**Average**
Crude production 2015 kbd (Assumed equal to Q4-2014)	**308**	**121**	**100**	**106**	**136**	**72**	**98**	**47**	**127**	**45**	**116**
Crude diff average to WTI in Q2/Q3/Q4 ($/b)	-0.4	-8.0	-7.3	-10.6	-11.4	-10.9	-1.8	-9.5	-6.1	-9.7	-7.5
Achieved crude price at assumed WTI price $/b	49.6	42.0	42.7	39.4	38.6	39.2	48.3	40.5	43.9	40.3	42.5
Revenue from crude sales million USD	5,579	1,855	1,560	1,524	1,917	1,029	1,726	695	2,034	663	1,858
NGL's production kbd	**84**	**100**	**45**	**10.5**	**0**	**0**	**35**	**34**	**0**	**0**	**31**
NGL price $/b	17.4	14.7	15.0	13.8	13.5	13.7	16.9	14.2	15.4	14.1	14.9
Revenue from NGL's sales million USD	533	537	246	53	0	0	216	176	0	0	176
Natural gas production (million cubic meters/day)	**37.0**	**88.0**	**10.0**	**2.7**	**10.0**	**7.5**	**32.0**	**15.0**	**2.2**	**0.9**	**21**
Natural gas price $/cm	0.10	0.06	0.13	0.15	0.15	0.20	0.12	0.14	0.16	0.17	0.14
Revenue from natgas sales million USD	1,351	1,927	475	148	548	548	1,402	767	128	56	735
Revenue pr year million USD	7,462	4,319	2,280	1,725	2,465	1,576	3,343	1,638	2,163	719	2,769
Total production in oil equivalents (Q4)	**610**	**729**	**201**	**131**	**193**	**120**	**302**	**158**	**141**	**50**	**264**
Lifting costs USD (based on total oil equivalents output)	3,340	3,991	1,100	717	1,057	657	1,653	865	772	274	1,443
Long Term debt by Q1-2015 (million USD)	**6,394**	**10,623**	**2,668**	**5,236**	**6,785**	**3,377**	**6,113**	**1,500**	**3,600**	**2,365**	**4,866**
Interest rate costs 2015 (million USD)	320	531	133	262	339	169	306	75	180	118	243
Interest rate costs as % of revenues	4%	12%	6%	15%	14%	11%	9%	5%	8%	16%	10%
Total Debt Ratio (Q1- 2015) LT debt to total capital	**26%**	**41%**	**24%**	**44%**	**58%**	**36%**	**35%**	**27%**	**26%**	**50%**	**37%**
Calculated free cash flow 2015:	3,803	-204	1,046	746	1,069	751	1,384	698	1,211	327	1,083
CAPEX 2014	**8,247**	**5,307**	**3,576**	**2,968**	**4,716**	**2,589**	**4,871**	**2,108**	**2,168**	**1,400**	**3,795**
Guided CAPEX 2015	4,948	2,919	2,200	2,000	2,700	1,900	2,900	1,000	1,450	705	2,272
Annualized CAPEX in Q1 2015	6,180	5,456	2,884	4,128	5,116	3,196	4,444	1,484	2,280	1,436	3,660
Calculated reduction in CAPEX for 2015 if no new capital	**4,444**	**5,511**	**2,530**	**2,222**	**3,647**	**1,838**	**3,487**	**1,410**	**957**	**1,073**	**2,712**
Calculated reduction in CAPEX for 2015 if no new capital %	**54%**	**104%**	**71%**	**75%**	**77%**	**71%**	**72%**	**67%**	**44%**	**77%**	**71%**
Guided reduction in CAPEX for 2015	3,299	2,388	1,376	968	2,016	689	1,971	1,108	718	695	1,523
Raised capital in Q1 (debt and equity)	990			4750	930	1480	1112	5	415	608	1,286
Guided reduced CAPEX plus new capital	**4,289**	**2,388**	**1,376**	**5,718**	**2,946**	**2,169**	**3,083**	**1,113**	**1,133**	**1,303**	**2,552**
Long term debt/Free cash flow	1.7	negative	2.6	7.0	6.3	4.5	4.4	2.1	3.0	7.2	4.3
Guided decrease in CAPEX 2015	**40%**	**45%**	**38%**	**33%**	**43%**	**27%**	**40%**	**53%**	**33%**	**50%**	**40%**
Realized decrease in CAPEX 2015 (annualized Q1)	**25%**	**-3%**	**19%**	**-39%**	**-8%**	**-23%**	**9%**	**30%**	**-5%**	**-3%**	**0%**
Possible new debt (Long term debt/Free cash flow <5)	**12,621**	**negative**	**2,562**	**-1,506**	**-1,440**	**376**	**808**	**1,989**	**2,454**	**-732**	**1,903**

Bloomberg Businessweek recently wrote a piece about drillers being forced to devote more revenues than ever to interest rate payments. They mention in an interesting comparison that Continental Resources spend almost as much as Exxon Mobil on interest rate payments. This is of course enough to raise an eyebrow, knowing that Exxon is a 20 times larger company than Continental and that by the end of Q1, Continental had 6.9 billion USD in long term debt compared with Exxon's 19.4 billion USD. Oil & gas companies reportedly accounted for one-third of the 36 corporate-debt defaults worldwide this year and missed interest payments are the leading cause of default according to an S&P report.

It is also worth mentioning that the shale companies results in Q1- 2015 has been very positively affected by the oil price hedges that many of these producers have benefitted from. For a producer like SandRidge Energy for example (28 kbd crude oil production in 2014), payments from the hedges reportedly accounted for 64% of the revenues in Q1-2015. Payments from hedges accounted for at least 15% of Q1-2015 revenues for about half of the oil & gas companies in the Bloomberg US E&P Index, according to a piece in Washington Post. Most of the hedging for Q1-2015 was probably executed around the summer of 2014 and hence guaranteed sales prices of around 95 $/b for WTI for the smart players who used that opportunity. Currently the WTI forward curve for 2016 is averaging at approximately 52 $/b, so hedging will not be able to save the day in 2016.

For several of the shale oil producers the oil price hedges gave them enough time to cut spending and avoid bankruptcy. At the same time costs are falling rapidly and productivity is rising as the producers focus on their most prolific regions. The oil price hedges have made it possible for the shale players to buy time to raise both equity and debt during the hard times. According to UBS, the producers have been able to raise about 44 billion USD in equity and debt during Q1-2015.

We looked at the largest 25 US shale oil producers and just during Q1-2015 they have been able to raise 32 billion in debt and 3.4 billion in Equity. Whiting Petroleum, who has a Long Term Debt vs Free cash flow ratio of 7.0, and a total debt ratio of 44% was able to raise 3.6 billion USD in debt and 1 billion USD in equity during Q1. Oasis Petroleum who has a Long Term Debt vs Free cash flow ratio of 7.2 and a total debt ratio of 50% was able to raise 145 million USD in debt and 463 million USD in equity in the same period.

Mill $ USD		2011	2012	2013	2014	2015
EOG Resources	Debt	0	1,234	0	496	990
	Equity	1,388	0	0	0	0
Conoco Philips	Debt	0	1,996	0	2,994	0
	Equity	96	138	20	35	0
Devon Energy	Debt	5,947	3,208	2,233	5,340	972
	Equity	0	0	0	0	0
Chesapeake	Debt	17,123	27,303	9,943	11,260	0
	Equity	0	0	0	0	0
Pioneer Natural Resources	Debt	197	1,777	467	523	0
	Equity	484	0	1,281	980	0
Anadarko	Debt	3,551	1,042	958	2,879	4,583
	Equity	30	103	146	121	12
Oxy	Debt	2,111	1,736	0	0	0
	Equity	50	85	30	33	19
Marathon Oil	Debt	0	2,197	0	0	0
	Equity	0	0	0	0	0
Whiting Petroleum	Debt	1,760	2,340	4,164	2,150	3,600
	Equity	0	0	0	0	1,050
Continental Resources	Debt	493	4,118	2,449	3,377	930
	Equity	660	0	0	0	0
BHP Billiton	Debt	1,374	12,817	9,157	6,251	
	Equity			0	0	
Apache	Debt	0	5,489	0	1,568	1,028
	Equity	0	0	0	0	0
Concho Resources	Debt	2,809	4,262	3,258	2,081	739
	Equity	0	0	0	932	741
Exxon Mobile	Debt	1,765	1,953	12,357	7,780	8,000
	Equity	924	193	50	30	0
Hess	Debt	522	2,278	535	598	0
	Equity	0	0	0	0	0
Chevron	Debt	400	4,271	8,378	7,431	6,110
	Equity	0	0	0	0	0
Noble Energy	Debt	2,348	150	1,885	2,528	0
	Equity	0	0	0	0	1,112
CimarexEnergy	Debt	55	750	174	750	0
	Equity	10	11	14	12	5
Crescent Point Energy	Debt	76	151	187	609	415
	Equity	365	1,969	0	659	0
Encana	Debt	14,603	1,721	0	1,277	
	Equity	0	0	0	0	
Murphy Oil	Debt	0	1,995	350	100	155
	Equity	0	0	0	0	0
Statoil	Debt	1,687	2,343	10,326	2,773	3,985
	Equity	0	0	0	0	0
CNOOC	Debt	2,881	5,462	13,802	6,022	
	Equity	0	0	0	0	
EP Energy	Debt	2,030	5,825	1,880	2,455	364
	Equity	0	0	0	669	0
Oasis Petroleum	Debt	800	400	1,600	620	145
	Equity	0	0	315	0	463
Summary	**Debt**	**62,532**	**96,818**	**84,103**	**71,861**	**32,017**
	Equity	**4,008**	**2,499**	**1,856**	**3,471**	**3,402**

Richard Robuck, vice president of Oasis Petroleum, said the companies hedges worked perfectly. The cash infusion gave Oasis the time it needed to cut back from 16 drilling rigs to four, which according to Oasis will allow the company to spend less than it brings in, even at lower prices. The company also seems to have plenty of room on its credit line and a plan to add new hedges for next year. To quote Richard Robuck in Oasis; *"There's a chance prices fall, and there's a chance they go up. It's the oil business. That's why we hedge."*

Oasis Petroleum was able to raise almost half a billion USD in debt during Q1 despite not being classified as an investment grade company. It will be a lot easier for companies classified as investment grade companies and companies with much lower debt ratios to raise new debt if needed. It is hence interesting to note that most of the US shale oil production is coming from companies with investment grade ratings.

Production from Investment grade companies	2014 - kbd
EOG Resources	359
ConocoPhillips	188
Marathon Oil	158
Devon Energy	149
Anadarko	144
BHP Billiton	134
Continental Resources	134
Chesapeake	129
ExxonMobil	105
Pioneer Natural Resources	101
Apache	89
Hess	85
Encana	76
Chevron	73
Oxy	63
Murphy Oil	61
Statoil	59
Noble Energy	56
CNOOC	55
QEP Resources	51
Reliance	25
WPX Energy	24
KNOC (S.Korea)	23
Sinopec Group (parent)	22
Sinochem	11
MDU Resources	11
Hunt Oil	10
Canadian Natural Resources (CNRL)	10
Mitsui	9
Southwestern Energy	7
Husky Energy	7
BP	5
EQT Corporation	4
Suncor Energy	4
Total	3
Eni	3
Schlumberger	3
GE	2
Marubeni	1
Freeport-McMoRan	1
Korea Gas	1
Mitsubishi Corp	1
Osaka Gas	1
Sum investment grade companies	**2,458**
Investment grade companies as % of total US shale	**55%**

There are however no doubt that there are a growing number of distressed oil & gas producers in the US. Moody's has a list of distressed companies (classified as rating B3 and lower) where companies from the oil & gas sector one year ago comprised 8% of the list. Now oil & gas companies comprise almost 17% of the list.

B3 Negative and Lower Sector Weightings (%)

	Current		1 Quarter ago	1 Year ago
Sector	Number of Issuers	6/1/2015	3/1/2015	6/1/2014
OIL & GAS	34	16.5%	13.6%	7.9%
SERVICES	27	13.1%	11.4%	13.9%
RETAIL	15	7.3%	7.6%	7.9%
MANUFACTURING	13	6.3%	6.5%	8.5%
MEDIA	13	6.3%	6.5%	6.1%
CONSUMER PRODUCTS	11	5.3%	4.9%	3.6%
GAMING: CASINOS	10	4.9%	5.4%	6.7%
TECHNOLOGY	10	4.9%	4.3%	6.1%
WHLSL DSTRBTN	9	4.4%	3.8%	3.0%
DEFENSE	8	3.9%	3.8%	5.5%
TELECOMMUNICATIONS	7	3.4%	3.3%	3.0%
CONSTR & ENGINEERING SERV	6	2.9%	3.3%	3.0%
METALS & MINING	6	2.9%	3.8%	4.8%
RESTAURANTS	6	2.9%	4.3%	4.2%
HEALTHCARE	5	2.4%	1.6%	1.8%
AIRCRAFT & AEROSPACE	3	1.5%	1.6%	0.6%
CHEMICALS	3	1.5%	2.2%	3.0%
ENERGY: COAL	3	1.5%	2.2%	1.8%
ENVIRONMENT: WASTE MANAGEMENT	3	1.5%	2.2%	0.0%
NATURAL PRODUCTS PROCESSOR	3	1.5%	1.6%	1.2%
PACKAGING	3	1.5%	1.6%	0.6%
TRANSPORTATION SERVICES	3	1.5%	1.6%	2.4%
AUTOMOTIVE	2	1.0%	1.6%	3.0%
PHARMACEUTICALS	2	1.0%	1.1%	1.2%
LEISURE & ENTERTAINMENT	1	0.5%	0.0%	0.0%
FOREST PRODUCTS	0	0.0%	0.0%	0.0%

Out of the 34 oil & gas companies on the list there are 17 E&P companies, but only 12 of these produced shale crude in 2014. It is also worth highlighting that these distressed companies only comprised 3% of US shale oil production in 2014.

Substantial Risk Companies (Moody's B3 or lower)	2014 - kbd
Halcon Resources	43
Sandridge Energy	28
Sabine Oil & Gas	17
Samson Resources	16
Midstates Petroleum Company	16
Resolute Energy Corporation	7
Lonestar Resources	6
Magnum Hunter Resources Corporation	6
Goodrich Petroleum	5
Rex Energy	3
Alta Mesa Holdings	3
Gastar Exploration	2
Sum Substantial risk companies	**152**
Sum Substantial risk companies as % of total shale	**3%**

It would hence matter very little to production even if all of these distressed companies were to go bankrupt. It would also be logical to assume that these companies' assets would keep operating as the companies were restructured and possibly sold to larger E&P companies.

The production of shale oil in the US is extraordinary skewed towards the bigger companies. It is even more skewed than the well-known 80-20 rule that can be used in so many areas. In fact; as much as 86% of US shale oil production is coming from only 20% of the companies. And maybe even more illustrating; as much as 71% of production is coming from only 10% of the companies.

Production from top 20% of the companies	2014 - kbd
Producers from 150-350 kbd	705
Producers from 100-150 kbd	1,143
Producers from 80-100 kbd	344
Producers from 60-80 kbd	340
Producers from 40-60 kbd	456
Producers from 20-40 kbd	494
Producers from 10-20 kbd	333
Sum top 20% companies	**3,816**
Sum top 20% companies in % of total shale	**86%**

Production from top 10% of the companies	2014 - kbd
Producers from 150-350 kbd	705
Producers from 100-150 kbd	1,143
Producers from 80-100 kbd	344
Producers from 60-80 kbd	340
Producers from 40-60 kbd	456
Producers from 20-40 kbd	162
Sum top 10% companies	**3,151**
Sum top 10% companies in % of total shale	**71%**

Based on the arguments above we would claim that access to capital would not be the key constraint on further production growth from US shale for the next couple of years. As long as the world is in the current *close to zero interest rate environments*, there will probably be enough money available that is chasing excess return.

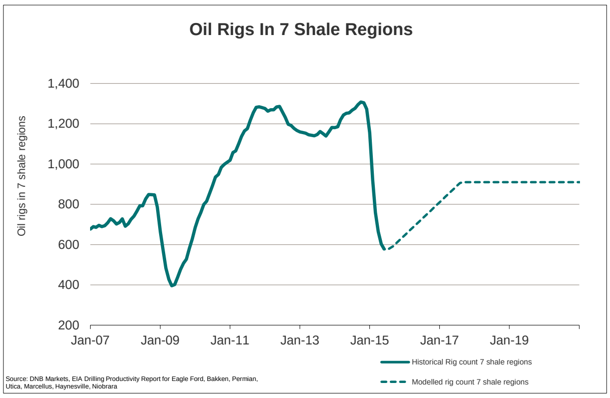
Another matter is if the companies themselves are willing to continue the borrowing spree. They are probably not. After having met nine of the largest shale oil producers in June on a DNB-trip, the impression is that it will be increased focus on protecting the balance sheets and to prioritize dividends for the dividend paying companies. The companies are likely to try to align their spending with their operating cash flow to a larger degree.

Costs in the shale industry is however coming significantly down, which means a potential 50% reduction in spending does not correlate with a 50% reduction in activity (number of wells drilled). The companies we met suggest a 30%-50% cost reduction compared with 2014 levels where roughly half of the cost reductions are due to cost deflation from service providers and the other half due to efficiency improvements.

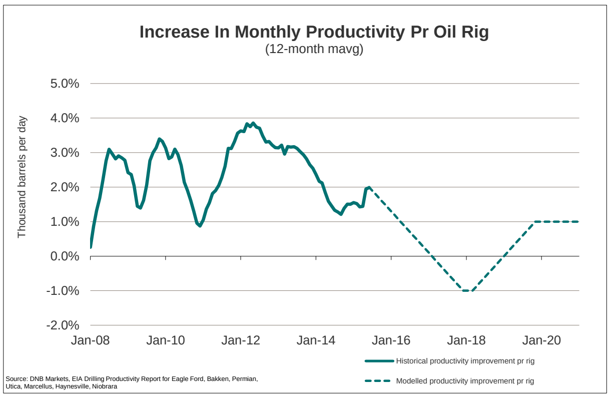
The companies did however say that cost deflation is about to trough and that cost inflation will probably come back with higher oil prices. The companies did not expect increased activity at the current oil prices, but a stabilizing WTI price above 65 $/b would probably do the job. We should hence probably not assume a structural cost deflation of 50%, but maybe 30-40%.

When the ramp up in activity starts it will not be as quick as the ramp down. It will take some time to build up service crews again after tens of thousands of oil workers have been sacked. We would model our activity ramp up according to Harold Hamm's statement that the increase in the rig count would be four times as slow as the ramp down in the rig count.

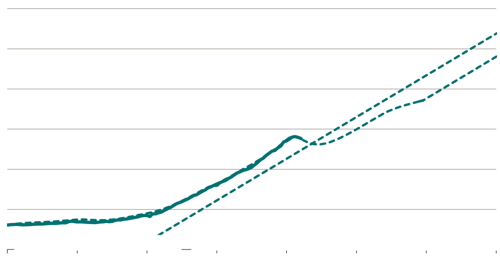
The number of horizontal oil rigs who has left the market now counts about 600 rigs and oil rigs working in the key seven shale regions have been reduced from about 1300 in November last year to about 600 rigs now. In our US shale model we assume that not all these rigs will return to the market in the coming years and that the ramp up will be quite slow. We assume that it will take two years to get back up to above 900 rigs and that many of the rigs are permanently obsolete (not modern enough to return to the market).



The only other factor we need to assume in order to model future US shale production is the contribution per oilrig working in these shale fields. Historically the contribution per rig has increased on average 2.4% per month since 2008. We are assuming that as the rigs are ramping back up, the productivity per rig is coming down as the companies again are tempted to target poorer acreage and projects with somewhat weaker IRR's.



We even model a period of falling efficiency per rig during the ramp up period, but then stabilizing at half the efficiency rate after 2020. With the above assumptions the US oil output from the seven shale regions will drop 350 kbd by year-end, but then as rigs are added crude production will increase from 5.2 million b/d (4.4 million b/d of this is shale) to 8.9 million b/d by 2020.

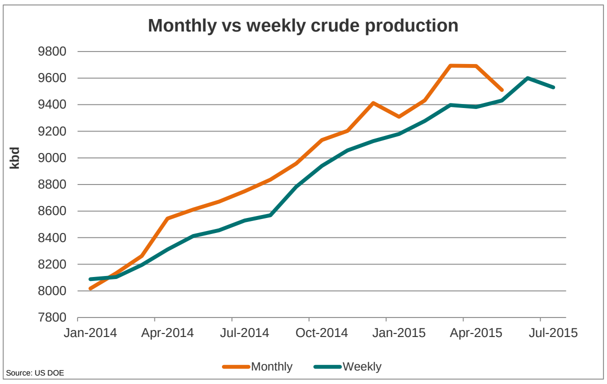


So far the lag effect from rig count to reduction in output has been quite long as can be seen in the graph below.

According to the companies we met in Texas in June there should be about a 5-month lag from the rig count to the effect on production. One of the reasons being the pad drilling effect as a company often will finish drilling all the wells in a pad before starting the completion of the wells. This creates mini inventories of drilled but not completed wells and as such when these pads are set into production it is not only one well that is starting up but maybe 10-20 wells at a time. This is probably one of the key reasons why production has performed so strong despite the drop in the rig count.

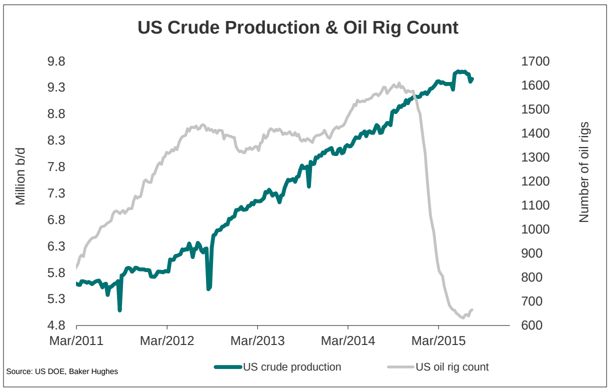
The recent Q2 financial report from Baker Hughes seems to be confirming this thesis as their quarterly earnings in Q2 surprised to the upside. This seems to be explained by producers completing wells that have already been drilled in combination with rising stage intensity, which basically means fracking more stages per well.

When that is said, the US Monthly production numbers for May was recently published and they showed a reduction in US crude production of 180 kbd from April to May. The monthly number is now more in line with the weekly production number than what we have seen for a while.



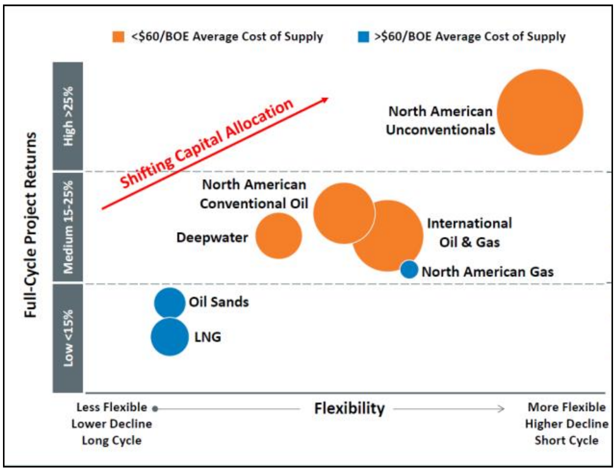
The largest part of the decrease was however in offshore GOM, even though Texas production also fell 42 kbd. We have long claimed that when the summer figures are released they would show that March was the peak month for US oil crude production in 2015. This prediction now looks to come through as March was reported at 9.7 million b/d while April was a tad lower and now May was reported at 9.5 million b/d.

The Baker Hughes oil rig count looks to have troughed and we do not expect any more meaningful reductions in the rig count going forward. The oilrig count has instead started to increase.



In fact it seems some players are already planning to increase their activity going forward. Whiting Petroleum for example reported rising Q2 production, which exceeded the high end of the company guidance, despite sales of 8 kbd of production during the quarter. The company recently increased its CAPEX guiding by 300 million USD to 2.3 billion USD where 185 million of these relates to the drilling budget.

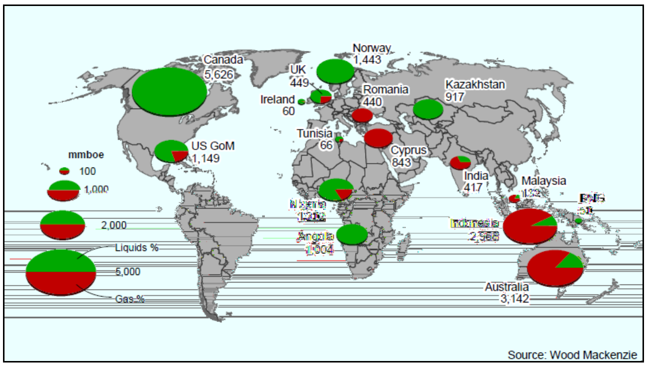
ConocoPhillips and other companies who can move their CAPEX between US onshore and global offshore spending have also made it clear that US onshore is going to be prioritized going forward. Even if internal rates of return (IRR's) were to be at the same level, US onshore would be prioritized due to its flexibility and shorter cycle. It basically means that a shale project is less risky than a large offshore project.



Source: ConocoPhillips

ConocoPhillips even estimate that the IRR's for North American unconventionals are much better than deep-water production. With that as the backdrop it should be a no-brainer which part of the oil market that will be prioritized going forward and which that will not. The above is already quite visible.

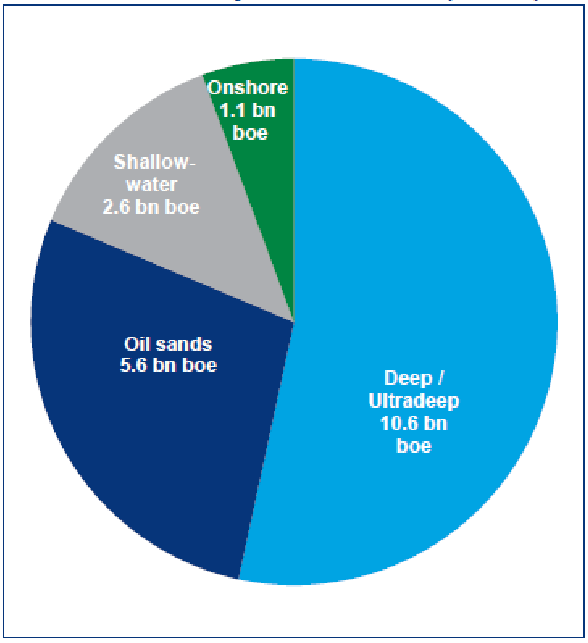
The global oil consultancy WoodMac estimates that 46 big oil & gas projects with 20 billion barrels in reserves have been deferred so far of which over 60% are liquids projects.



Source: Wood Mackenzie

More than half of those reserves are offshore resources (US GOM, West Africa, Norway, etc) and more than a quarter are Canadian oil sands projects.

Deferred reserves by resource theme (bn boe)



Source: Wood Mackenzie

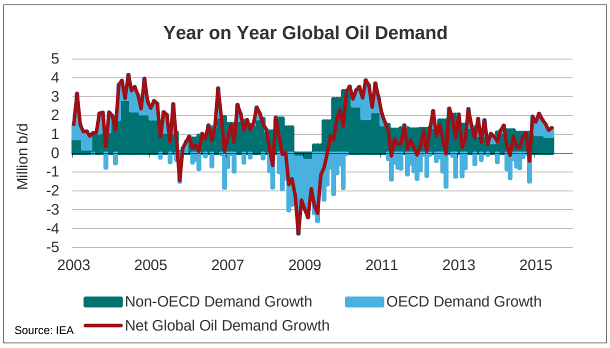
As a last point under this chapter it has been interesting to note that production in North Dakota (which should be more sensitive to oil prices than Texas production due to the lower price diffs that are achieved there) in fact increased in May to 1.2 million b/d, up from 1.17 mbd in April. This means that production in May was the highest reported so far this year for North Dakota. Not only did North Dakota oil production increase by 32 kbd in May, the drilling permits for June increased by 42 permits to 192.

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL & GAS DIVISION
2015 MONTHLY STATISTICAL UPDATE

Month	Monthly Oil Production	Wells Producing	Average Daily Production	Permits				Spuds	Average Rig Count
				Dev	Ext	WC	Total		
Jan	36,932,588	12,202	1,191,374	250	0	3	253	180	188
Feb	32,993,365	12,204	1,178,334	196	1	0	197	134	133
Mar	36,908,968	12,446	1,190,612	189	0	1	190	124	108
Apr	35,071,361	12,545	1,169,045	168	0	0	168	92	91
May	37,235,915	12,659	1,201,159	148	2	0	150	101	83
Jun				192	0	0	192	108	78
Jul									
Aug									
Sep									
Oct									
Nov									
Dec									
Totals	179,142,197		1,186,372	1143	3	4	1150	739	114

7 Demand

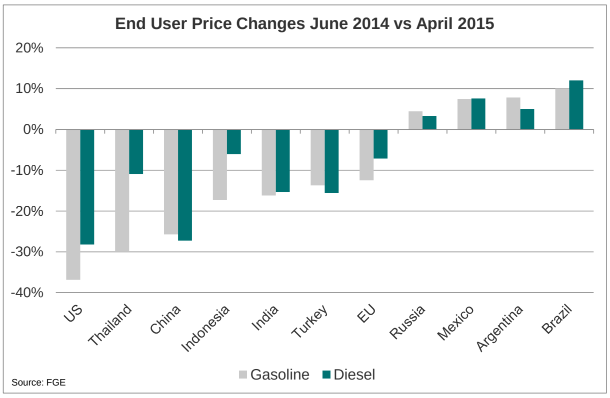
Global oil demand growth has performed a lot better so far in 2015 than what we saw last year, despite some weaker numbers from the non-OECD recently.



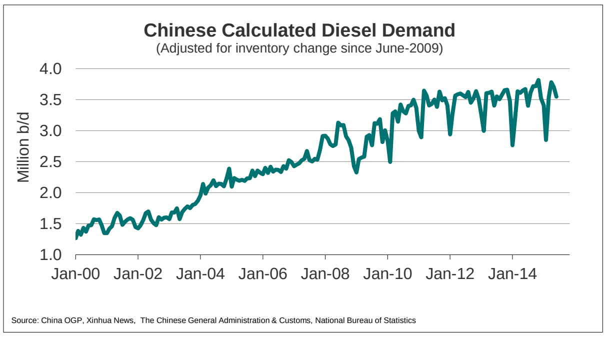
First half 2015 oil demand growth has been almost 1.5 million b/d according to IEA data. In 2014 global oil demand was growing only 0.7 million b/d, so we are on track to see a 100% improvement in the growth for 2015.

Demand change in %	Change 2014	YoY Last 3 mts	2015 YTD Chg:	Forecast 2015	Forecast 2016
North America (Canada, Mexico)	-1.4 %	-2.7 %	-2.8 %	-1.9 %	-1.0 %
US	0.4 %	2.5 %	2.5 %	3.0 %	1.0 %
OECD Europe	-1.6 %	0.7 %	2.6 %	1.8 %	1.0 %
Australia, New Zealand, Japan, Korea, Chile	-2.5 %	0.3 %	-0.4 %	-0.2 %	0.0 %
Europe/Africa Med & FSU	2.3 %	-1.0 %	0.0 %	-0.7 %	-1.5 %
Middle East AG excl. Iran and Saudi	0.4 %	-1.2 %	-1.8 %	-1.9 %	-2.0 %
Iran	0.5 %	1.1 %	0.1 %	2.0 %	4.0 %
Saudi Arabia	6.9 %	2.7 %	3.8 %	3.4 %	3.0 %
Asia Pacific/East Africa excl. China and India	2.3 %	3.0 %	2.9 %	3.0 %	3.0 %
China	3.0 %	3.9 %	3.7 %	3.3 %	2.3 %
India	2.3 %	5.1 %	4.3 %	6.1 %	7.0 %
West Africa	-0.4 %	1.1 %	0.6 %	0.8 %	1.0 %
Latin America (excl. Mexico)	2.3 %	0.2 %	0.9 %	1.0 %	1.0 %
Total World	**0.8 %**	**1.5 %**	**1.8 %**	**1.7 %**	**1.3 %**
Demand change in Million b/d	**Change 2014**	**YoY Last 3 mts**	**2015 YTD Chg:**	**Forecast 2015**	**Forecast 2016**
North America (Canada, Mexico)	-63	-115	-124	-94	-37
US	77	475	479	567	193
Europe	-219	91	348	228	151
Australia, New Zealand, Japan, Korea	-213	24	-35	-37	24
Total OECD	**-419**	**475**	**668**	**664**	**332**
Europe/Africa Med & FSU	176	-77	3	-75	-112
Middle East AG excl. Iran and Saudi	7	-31	-46	-49	-52
Iran	10	21	2	36	77
Saudi Arabia	210	90	115	98	102
Asia Pacific/East Africa excl. China and India	197	265	261	271	272
China	304	409	381	340	250
India	87	198	167	246	282
West Africa	-6	14	8	13	13
Latin America (excl. Mexico)	153	11	59	54	72
Total Non-OECD	**1,137**	**900**	**948**	**935**	**903**
North America	13	360	355	473	157
Europe/Africa Med & FSU	-43	14	350	154	38
Middle East AG/Asia Pacific/East Africa	601	976	843	906	956
Middle East AG	227	80	70	86	127
Asia Pacific/East Africa	374	896	773	820	829
West Africa	-6	14	8	13	13
Latin America (excl. Mexico)	153	11	59	54	72
Total World	**718**	**1,375**	**1,616**	**1,599**	**1,235**

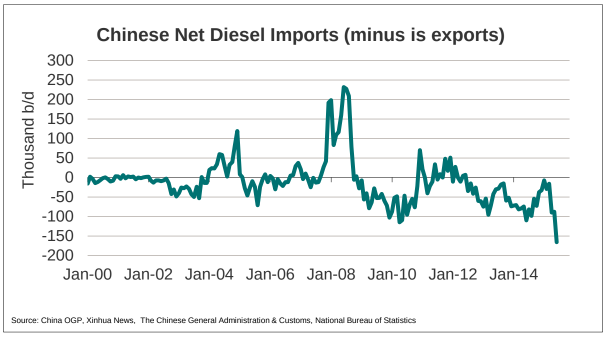
A 100% improvement in the growth is of course a strong number, but we do believe that the price drop from 115 $/b in June last year is the main reason for the better demand performance in 2015. It is not only the US who has seen a price drop for the consumers. Consumers in important consumer countries like China, India and Indonesia have also seen the benefit of lower prices on the key petroleum products in 2015.



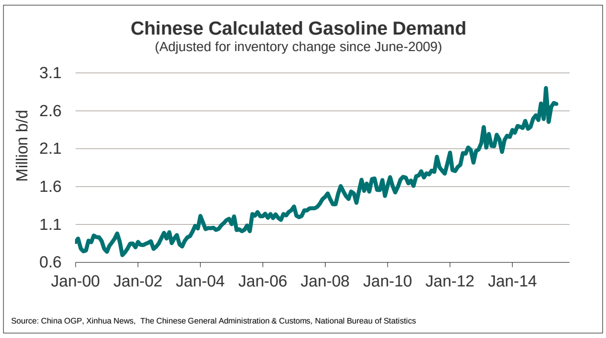
In China we have seen that diesel demand has continued to suffer, mainly due to the weaker construction sector.



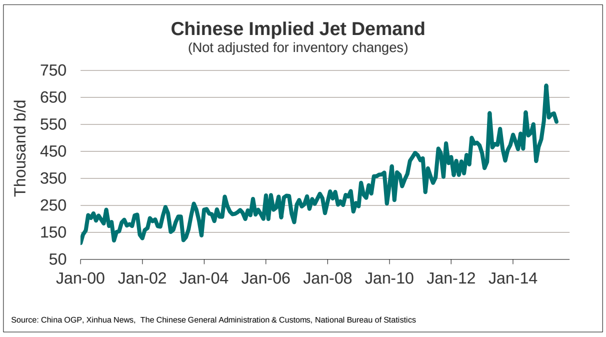
Another sign of the weakness in the Chinese diesel market is that in June, the Chinese exports of diesel reached a record 166 kbd. There is a quota for diesel exports from China, but the National Development and Reform Commission (NDRC) is under intense pressure to grant more diesel exports quotas as teapot refineries have been allowed to import crude oil recently. These teapot refineries which have historically run a lot of resid fuel as feedstock instead of crude are hence likely to increase their runs and thereby increase their output of diesel. This will probably make the oversupply situation for diesel in China even worse.



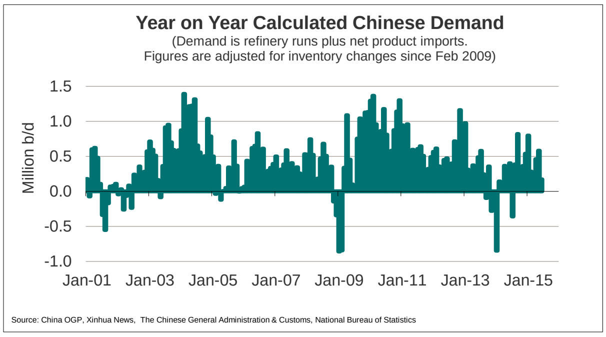
Gasoline demand is however still performing strongly in China on the back of still high car sales.



Jet fuel demand is also performing well. To us it makes sense that the refined products that are tilted towards personal consumption are performing better than the products which are more related to the investment cycle.

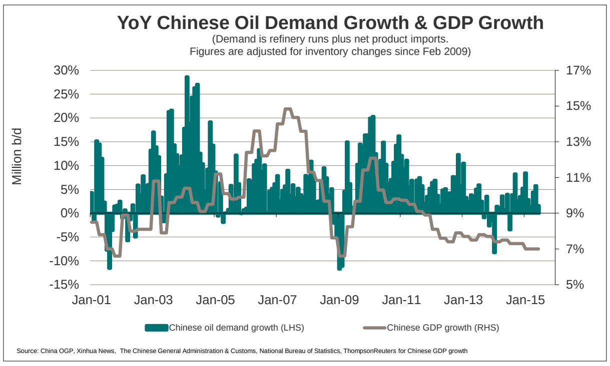


It seems to us that many people believe that Chinese oil demand has suffered in 2015 based on the weaker economic growth data that has been reported from the country, but so far the oil demand growth has in fact been pretty strong at 0.4 million b/d. This is more than twice as strong as the demand growth we saw in 2014.

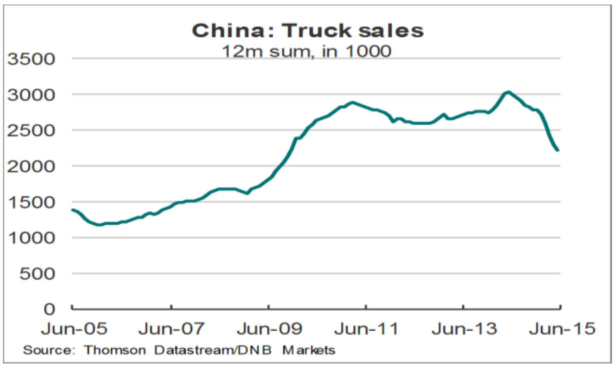


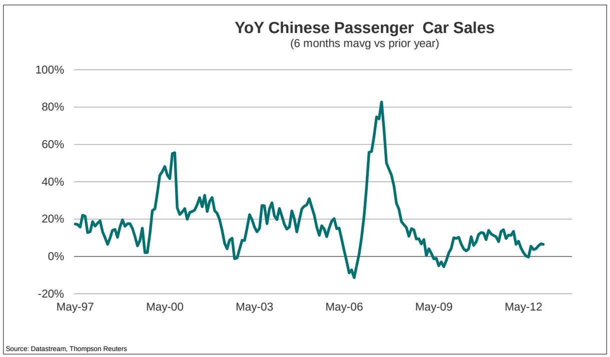
We did however see quite weak demand growth for June recently reported. June is the latest month we are able to calculate the Chinese demand growth. In June the Xinhua News Agency reported a 3.8% inventory increase for refined products. Both diesel stocks and gasoline stocks were reported to have built. Year on year diesel demand fell to a weak minus 120 kbd, while gasoline demand growth wakened from 330 kbd in May to 225 kbd in June. Jet fuel demand growth also weakened from 130 kbd in May to a negative of 35 kbd in June.

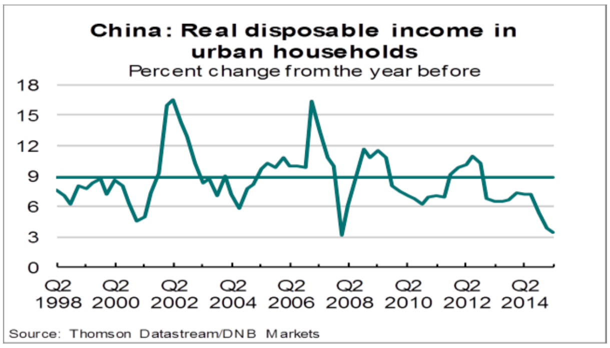
There is a risk that going forward the Chinese petroleum consumption may start to better reflect the weakening macro-economic indicators we have seen during 2015. Chinese economic growth was reported at 7%, but many economists really doubt that number and believe that real growth must be weaker than that.

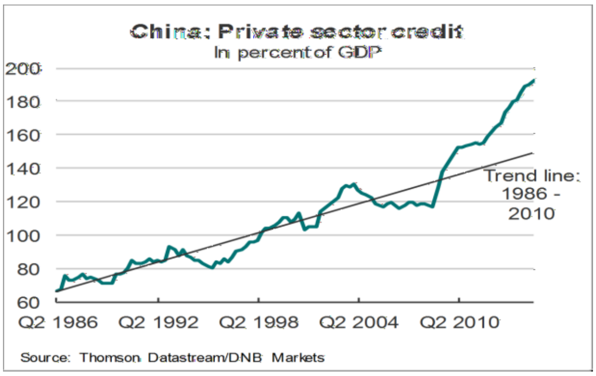


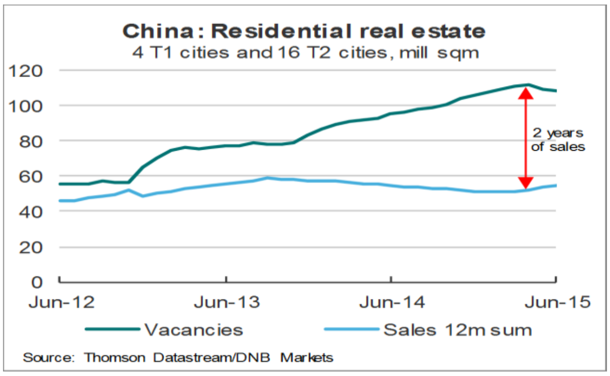
The charts below certainly suggest that something negative is happening to the Chinese economy and compared with the numbers below it looks like a mystery that Chinese oil demand is up 0.4 million b/d (4.1%) so far this year.







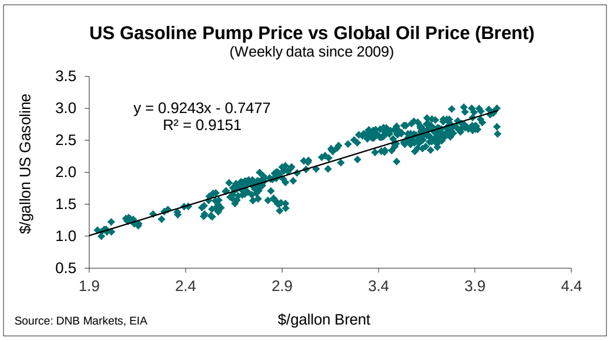




Based on the above we believe it is plausible to reduce our assumptions for Chinese oil demand growth for the rest of the year and the coming couple of years. Instead of 0.4 million b/d of growth for the second half of 2015, we are revising it down to 300 kbd and for 2016 and 2017 we assume 250 kbd and 200 kbd of growth respectively. Chinese crude imports are another matter that has less to do with domestic Chinese consumption and will instead be discussed in the chapter about strategic petroleum reserves.

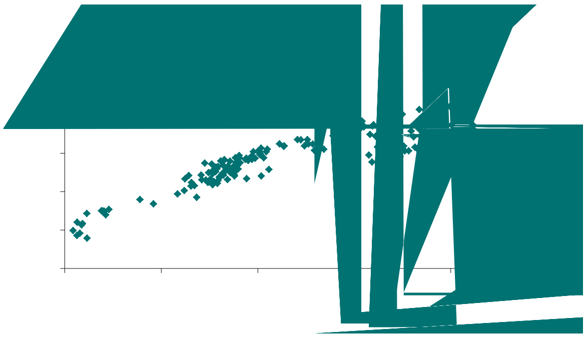
The country that really stands out with respect to much better demand growth than last year is the US. In the US there has always been a very close relationship between changes in prices at the pumps and changing consumer behavior.

Since the Americans have quite low taxes at the pump, the price change that hits the consumers becomes so much larger than for example in Europe. This means that the correlation between the US gasoline prices at the pumps and the global oil price (Brent) is very strong as can be seen in the graph below.

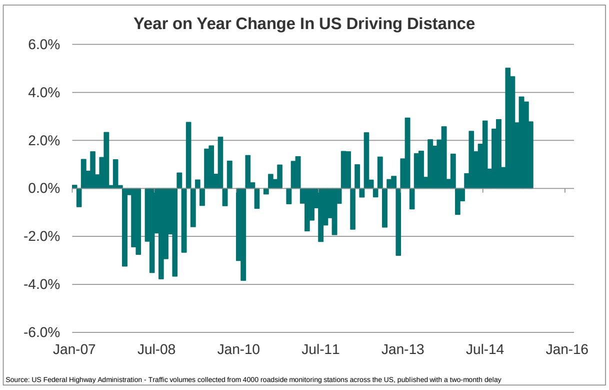


It is also worth mentioning that the correlation between the US gasoline prices at the pump is stronger vs Brent than vs WTI. This is due to the fact that the gasoline market is a global market and it is allowed to export as much gasoline as you want from the US.

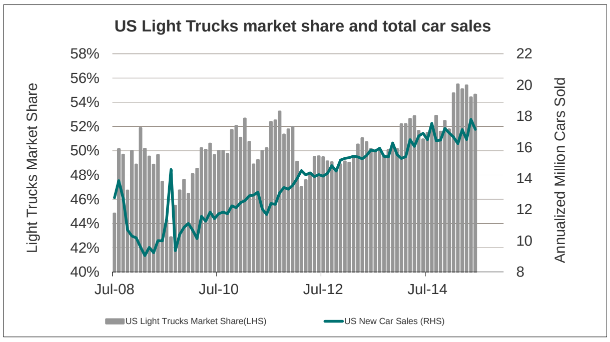
This stands in contrast to crude oil of course where WTI is more of a regional rather than a global crude marker grade since it is not generally allowed to export US domestically produced crude oil.



Based on the above it is pretty clear that when the Brent price changes, the US pump price for gasoline changes as well. And when the US pump prices change meaningfully, the consumer behavior changes meaningfully as well. As the gasoline price drops the Americans start to drive longer distances.

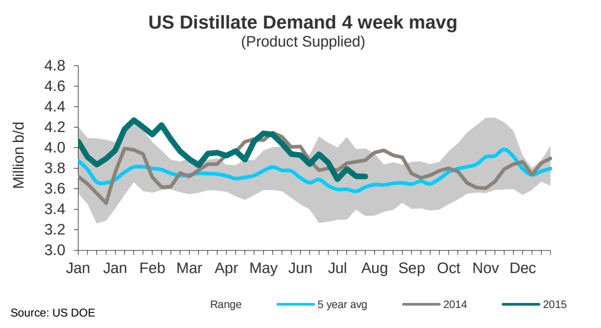


And not only do they drive longer distances; they also buy larger vehicles again. It is noteworthy to see how Americans start buying light trucks to a larger extent as soon as the oil price (gasoline price) starts falling.



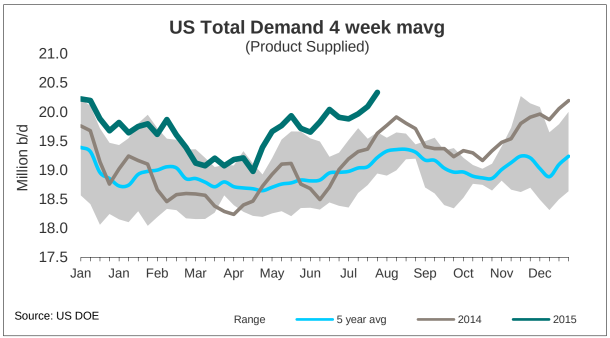
The above has led to a very strong year for gasoline consumption in the US so far in 2015. In fact on a 4-week moving average basis, US gasoline demand is up about 500 kbd (about 5%) vs last year.

Distillate demand is however slightly weaker than last year.



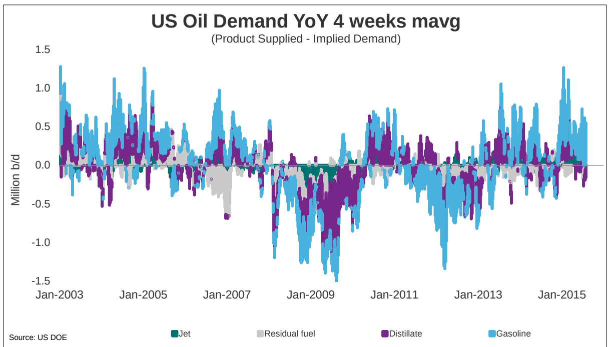
Source: US DOE

In total, US petroleum consumption is about 0.7 million b/d higher than last year, but note that the year-on-year comps become harder in the second half of the year.



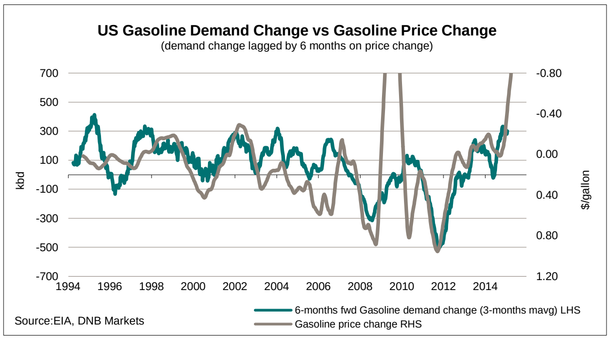
Source: US DOE

Currently almost all of the demand increase is in gasoline, as can be seen in the graph below.



Source: US DOE

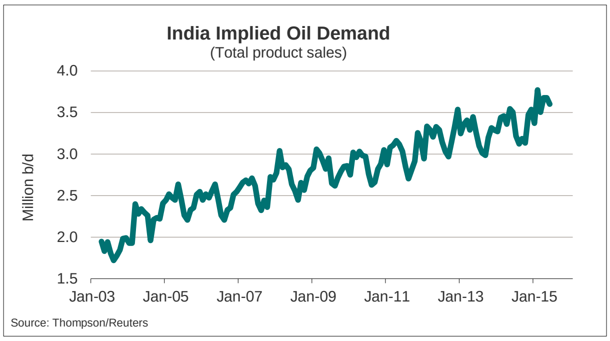
Overall the price elasticity in US gasoline consumption is extremely strong. It would have been much easier to be an oil analyst if all the countries in the world were showing a demand relationship vs price changes like in the US.



Source:EIA, DNB Markets

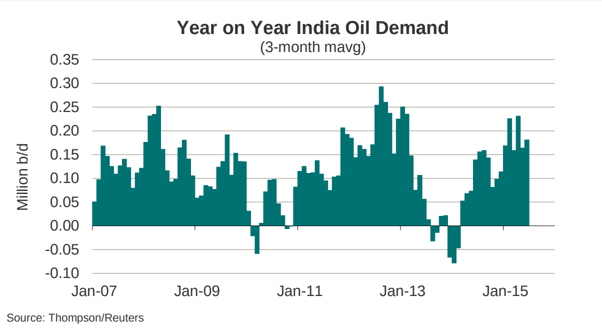
In our global supply-demand balance we have assumed a US oil demand increase of 3% for 2015. As we forecast somewhat higher oil prices in both 2016 and 2017 than for 2015 we are assuming lower US oil demand growth for those years. In our global supply-demand balance we are assuming that US oil demand growth slows from 570 kbd in 2015 to 190 kbd in 2016 and goes back to zero in 2017.

In addition to China and the US it is worth showing some details for Indian oil demand growth. India is now showing improved economic growth after Narendra Modi came to power. Implied oil demand has reached above 3.5 million b/d and is approaching Japan in size.



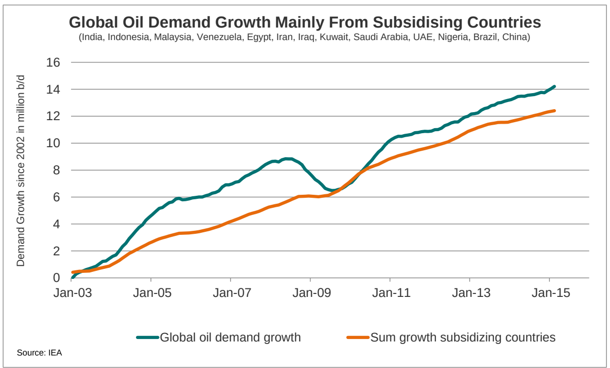
Source: Thompson/Reuters

On the contrary to Japan however, Indian oil demand is rising quite rapidly. Year to date average growth in Indian sales of petroleum products is 170 kbd (5.1%).



This is of course coming from a much lower base than China, but India will most likely continue to increase its demand for petroleum products quite meaningfully on the back of strong economic growth.

Thinking a bit longer term we believe it is worth mentioning that global oil demand growth during the past decade has been protected by subsidies. If we look at global oil demand growth during the past 12 years, the growth has been about 14 million b/d according to IEA data. How much of this has been coming from subsidizing countries?



The answer is about 86%. So what is going to happen if the subsidizing countries loosen up on that policy? Well, it is at least hard to imagine that it is going to unleash stronger demand growth. We would instead assume that the global oil demand growth that we have seen during the past 12 years would have been somewhat weaker without the subsidies. We believe there would still have been demand growth on the back of urbanization, population growth and a growing middle class, but the demand growth would probably have been somewhat weaker.

This is interesting with the backdrop that countries like India, Indonesia and Thailand have decided to remove petroleum subsidies and China changed its pricing policy two years ago.

Now in July we have even seen one of the key Middle Eastern producers lifting subsidies for petroleum products. UAE, one of the largest OPEC producers, will link domestic gasoline and diesel prices to the global oil markets, starting in August. The regulated price of gasoline in the UAE has this summer been about 50 cents per liter. In Norway we pay about 170-180 cents per liter. In Saudi Arabia the price is about 16 cents per liter.

The UAE minister of Energy said in a statement that the removal of petroleum subsidies is a part of the government's plan to diversify sources of income, strengthen the economy and increase the competitiveness.

According to a recent IMF report the low international energy prices have opened a window of opportunity for countries to move toward more efficient pricing of energy. This seems to be mirrored in a statement from the UAE Energy minister who says, *"moving to international prices is a very rational and correct policy to undertake at this moment because the international oil prices are very low".* UAE will be saving 29 billion USD per year by changing its subsidy policy. Saudi Arabia could be saving 107 billion USD by imposing the same change. Global energy subsidies are 5.3 trillion USD this year according to the IMF report so there could be a lot to gain by many energy-exporting countries by changing this policy.

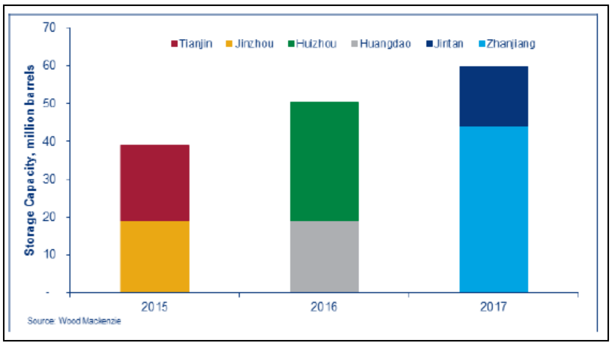
8 Chinese SPR

As oil infrastructure is expanded it creates "artificial" demand for oil as described in chapter 9 about missing barrels. One of the key parts of the missing barrels are strategic petroleum reserves (SPR) as many of those barrels are not reported anywhere.

Strategic petroleum reserves are crude oil or refined product stocks held by governments as security vs potential oil supply disruptions. In 2014 China imported 62% of its crude throughput. This is 19% higher than ten years ago. The country has in other words become gradually more addicted to imported crude oil. And large shares of those imports are coming from geopolitically exposed regions. In fact more than half of China's crude imports are coming from Saudi Arabia, Iran, Iraq and Russia. Based on that fact it is no wonder the Chinese have prioritized expanding its SPR in recent years.

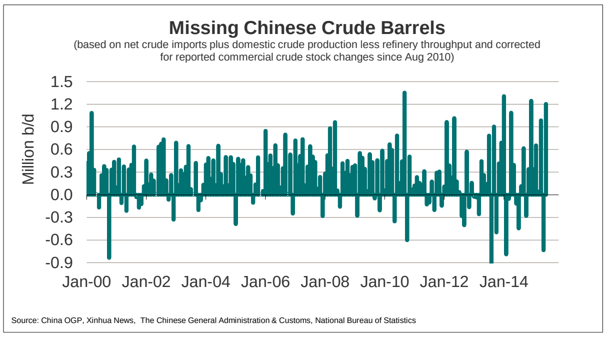
According to a recent WoodMac report, SPR accounts for about 40% of the total crude storage capacity in Asia, which is equivalent to about 38 days of net imports. Members of IEA for comparison are required to maintain reserves equivalent to 90 days of net oil imports.

China and India are together expected to add about 185 million barrels to SPR from 2015-2017. For China's part the country started building its first phase SPR in 2006 and by 2008 had reached about 100 million barrels. Phase two is currently under construction and according to WoodMac about 40 million barrels are already filled in Lanzhou and Dunshanzi and another 40 million barrels will be filled in Tianjin and Jinzhou by the end of 2015. The total phase two is supposed to consist of 190 million barrels and the remaining 110 million barrels are scheduled to four different locations for completion in 2016 and 2017.



Source: WoodMac

Based on the above we should see about 80 million barrels of SPR build in China in 2015. This is equal to 220 kbd for the whole year. In theory then the missing barrels in China should be quite close to that number. We calculate the missing crude barrels in China to have been about 0.4 million b/d during 1H-2015.



Refinery throughput (crude demand) was 10.4 million b/d vs imports and domestic crude production of 10.8 million b/d. If all these missing barrels in China are in fact SPR builds, then it amounts to 73 million barrels for the first half of the year. There is however some direct burning of crude in China that is not reported anywhere and there are also very blurry lines between purchases of crude to SPR and for commercial storage in China.

According to a Reuters story there will be added about 26 million barrels of commercial crude storage in China in coming months from companies like Vopak and SDAIC. Commercial storage has probably also been added so far in 2015 and since it is the same traders buying for commercial as strategic storage one can never be sure where barrels are ending up at the end of the day.

Since there should be more additions in the second half of the year of both commercial and strategic storage capacity, it is probably fair to assume that the missing barrels in the Chinese crude balance will continue to be at the same level in 2H-2015 as in 1H-2015.

And going further out in time the Chinese have planned for a phase 3 of SPR facilities that will bring total capacity to about 500 million barrels. These plans are still somewhat uncertain it seems, but if carried through will continue to support imports of crude oil into China.

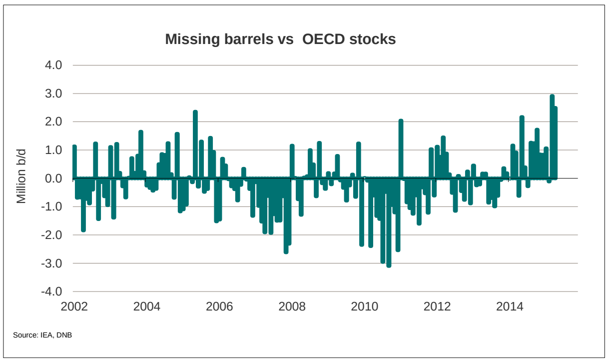
We hope most of our readers by now would know that there is a large difference between increases in Chinese crude imports and increases in oil demand. Sometimes it does however seem like journalists and others are misunderstanding this difference. Increases in crude imports are not necessarily a sign that oil demand is growing and vice versa.

Last year is a perfect example of this when crude imports increased by a large 550 kbd while demand (calculated consumption) only increased by 190 kbd. There could easily be periods also in the future where for example the increase in Chinese crude imports is much stronger than the increase in calculated demand. This will particularly take place in periods of large SPR fillings.

9 Missing barrels

Missing barrels has popped up as a recurring theme during the last couple of months. Several analysis we have read are now suggesting that the rising number of missing barrels means that demand in reality is much stronger than what the IEA is reporting.

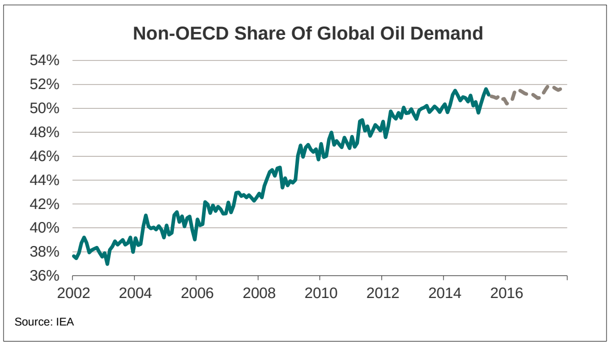
First of all it is probably important to define what missing barrels are. There are a number of different options available for that definition. The way we think about it, the missing barrels are the difference between what we can identify of oil stock changes and the theoretical stock change on the basis of the global supply-demand balance.



If the theoretical stock build based on the reported supply-demand balance is much higher than the identified stock build, then this suggest that either demand is stronger than reported or supply is weaker than reported.

Alternatively the stock build is in reality higher than what is reported. Based on the above it is not valid to automatically draw the conclusion that since missing barrels have been growing, this means that demand is under stated. In order to draw that conclusion the starting point must be to assume that both supply and the reported stock levels are correct. That could be a far-fetched assumption.

Maybe the most difficult part of this issue is what kind of stock definition we should measure the calculated stock change against. Should we measure against changes in observable OECD stocks? Well, this may have worked well 10 years ago when the OECD held by far the largest share of the oil market, but it is probably not the right way to measure it any more after the non-OECD region has captured the largest market share.



The OECD represented 48.5% of the global oil demand in Q2-2015 according to the IEA data. Nevertheless, the changes in the OECD stocks vs the calculated global stock change is the way many analysts calculate the missing barrels. But why would OECD stock changes be a particularly good measurement for the global supply-demand balance anymore? We would agree that this way of calculating missing barrels does provide some information when the missing barrels are suddenly growing compared with historical numbers. There could however be other explanations than just unreported demand behind this change.

OECD stock changes do not capture the number of barrels in transit on ships and in pipelines and neither does it of course capture the massive expansion in oil infrastructure in the non-OECD in recent years. If we measure missing barrels only vs OECD stock changes we would claim that missing barrels should be on the rise due to new built refineries, terminals, pipelines and strategic inventories in the non-OECD. Just as an example; a new 200 kbd refinery will, as a rule of thumb, need about 10 million barrels as operating storage. These 10 million barrels will just sit in the inventory and will not be consumed by anyone and as long as non-OECD infrastructure keeps expanding so should the missing barrels if we only use OECD stocks as the measure.

Another option could be to adjust the stock change reported from OECD with the market share of global demand and hence assume that the stock change in the OECD and non-OECD is relative to the size of the market. So since OECD has 48.5% of the market and the stock change in the OECD in Q1-2015 was reported at 0.9 million b/d (Q2 is still not reported), the global stock change could be calculated to have been 0.9/0.485 = 1.86 million b/d. This number is actually very close to the oversupply that the IEA was reporting for that period.

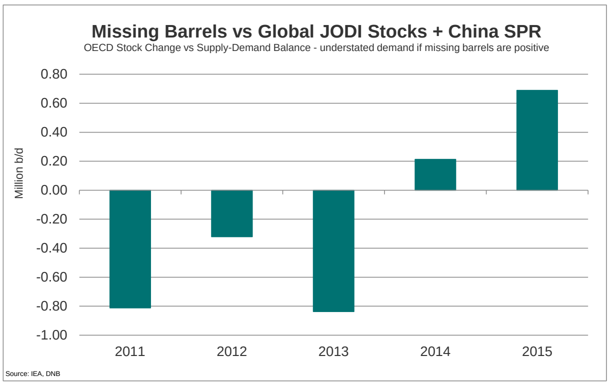
For the second quarter we still do not have the June-numbers, but the OECD stock build in April/May is reported at 0.7 million b/d. This would then translate to an oversupply of 0.7/0.485 = 1.44 million b/d. This is a much smaller number than the 3.3 million b/d that the IEA is reporting as the global over supply for Q2-2015 and is as such an argument to suggest that maybe demand was much stronger than what has been reported.

Another way to sense check the IEA supply-demand balance is to use the JODI database. This data is from the cooperation between OPEC, APEC, IEA, etc and includes stock levels for many non-OECD countries as well as OECD countries. The database has been constantly improving in recent years and more and more countries contribute. It probably did not make much sense to use the data 5 years ago but now it is likely giving a better gauge of the global picture than just using the OECD stocks reported by the IEA.

The JODI database also includes strategic stock builds for the countries that are contributing, but unfortunately China is not contributing. We hence have to keep another separate database with China data on the side.

If we just look at the reported stock builds so far in 2015 from the JODI database it averages 1.4 million b/d, and in May the reported stock build is a massive 3.6 million b/d. If we also include the missing barrels for China which was probably mainly strategic stock builds we can add another 0.4 million b/d. If these numbers are correct it means the total global stock build so far this year has been 1.8 million b/d. We have then just used the JODI database and assumed that the missing barrels in China are strategic stock builds.

Our supply-demand balance is showing an oversupply of 2.5 million b/d so far this year, which means that the missing barrels are about 0.7 million b/d with this way of looking at it.



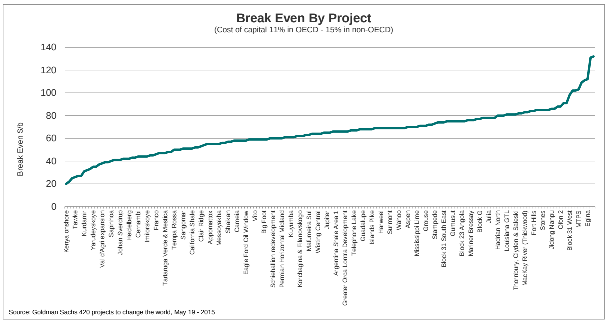
These barrels could be under reported demand or over reported supply, or maybe we will see large stock revisions in the coming months. We will show under the global supply-demand chapter how the forward-looking balance is affected if we assume that these barrels in reality should be classified as demand.

10 CAPEX cuts – decline rates

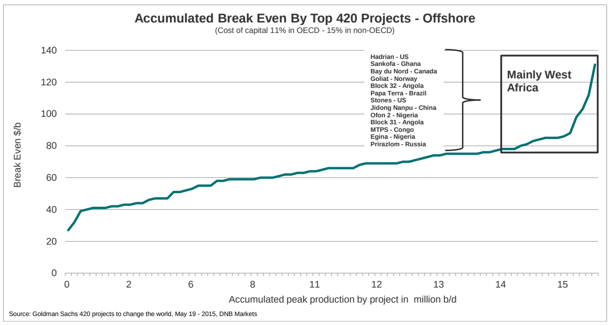
According to WoodMac the global oil industry has cut global upstream spending in 2015 by about 130 billion USD (25%). This is more than twice as much as during the financial crisis in 2009. WoodMac also estimate that the largest global energy companies have shelved over 200 billion USD of spending in over 45 big oil & gas projects. As a result of this several sources report that over 160.000 oil workers have lost their job so far in this downturn. In late July Royal Dutch Shell said it would sack 6.500 people and cut its CAPEX spending by 20% as one of the latest signs of the mayhem now visible in the global oil industry.

High oil prices and low oil prices unleash change in behavior. High and rising oil prices means increased spending (investments) which over time leads to more production and low oil prices leads to cuts in spending that over time will bring the market into a new equilibrium as production starts to suffer. The oil industry is cyclical and will probably continue to be cyclical, even though the cycles now may shorten compared with earlier history due to the new shale industry.

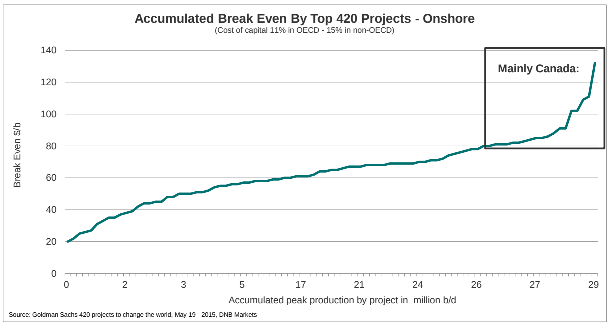
The production of oil in 2020 will be much lower than earlier estimated due to the large cuts in global E&P spending. The Saudi strategy to maintain market share will probably work. That does not mean that the market will revisit 100 dollars a barrel oil in our opinion. But it probably means that we will have to see somewhat higher oil prices going forward in order to lift the activity levels in the oil industry in order to avoid global decline rates to accelerate. To us it does not look like the market will necessarily need many new barrels coming from the most expensive sources during the coming 5-10 years. All the projects that are highest up the cost scale are at risk for not being sanctioned. More than 80% of the projects in the cost graph below are however sanctioned. Unsanctioned projects high on the cost scale are of course those most at risk for never being executed going forward.



The most expensive projects in the offshore industry are mainly in West-Africa, but there are also sizeable expensive barrels from projects in Norway, US GOM, China and Brazil.



When it comes to the onshore industry it is pretty clear where the most expensive barrels are coming from. The answer is of course Canada.

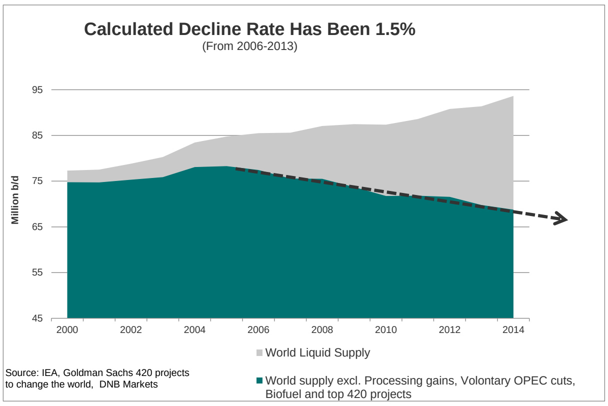


One thing is that the oil market may not need ultra-deep-water resources and Canadian oil sands in order to balance in the coming ten years, but we believe the market cannot afford to see a doubling of the decline rate in existing production.

Decline rates can be calculated bottom up or top down. You can try to model every field of the 70.000 oil fields in the world and then build upwards, but then you would have to make a lot of assumptions and it will most likely be too much to control so you would end up with a black box where you are not able to explain what is going on at the aggregated level.

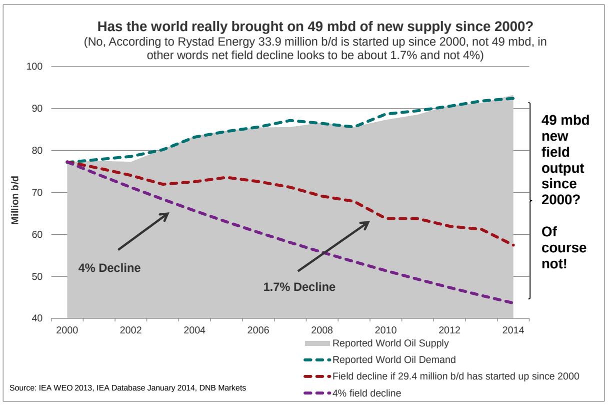
We have seen too many bottom-up attempts to be very comfortable with that approach. On a global scale there are just too many projects and oil fields to keep in control. It is just the same with refineries. No consultancies are able to provide the full picture of the global refinery throughput for a given quarter for example. It feels a lot safer to go the other way; that is top down. After all we are trying to say something meaningful about the big picture and not a tiny part of a particular market. As we have said before; we would prefer to be approximately correct rather than precisely wrong.

One way of getting global decline rates approximately right would be to start with the total global supply and then deduct all the production that has obviously not yet reached decline, or is still in ramp up. One would also need to remove the supply coming from biofuels which does obviously not have natural decline and the more than 2 million b/d of processing gains from the refineries. These processing gains are just additional supply compared with crude input to the global refineries since you will get about 2.5% more products out of a refinery than the crude oil you put in. You also have to remove voluntary OPEC cuts of course in order to get to the structural picture.



Based on the above we reach a calculated net decline rate for global liquids supplies of 1.5% since 2006. We have then used the Goldman Sachs top 420 projects to change the world report in order to find the projects that should not be part of the decline base. This means that the top 420 projects are not included in the green color in the graph above. This calculated decline rate of 1.5% stands in contrast to the 4% annual decline rate that the IEA use in its projections for future supply (WEO 2013, page 459). If these 4% are to be used for anything, they should at least not be used for the whole liquids supply base it seems.

If we take a step back to the millennium change and use the 4% decline on that starting production of 77 million b/d, the supply from that existing base would have dropped to 44 million b/d by 2014. Liquids supply was in 2014 reported to have been 93 million b/d by the IEA so the diff is 49 million b/d. If net world decline on the existing base from year 2000 has been 4% it would in other words have meant that the world has been able to add five new Saudi Arabia’s since year 2000. The problem is that we are not able to identify 49 million b/d of field start-ups since year 2000. This suggests that net field decline could not have been 49 million b/d (4%). We are only able to identify 34 million b/d of project start-ups since year 2000, which suggest that instead of 4% net decline the decline has instead been 1.7%.

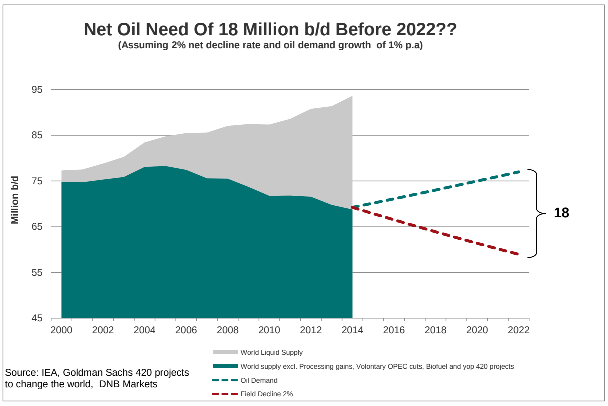


This is very close to the number we figured out by using the Goldman top 420 report and makes us more confident that 1.5%-2% is probably the most correct net decline number for the past 14 years.

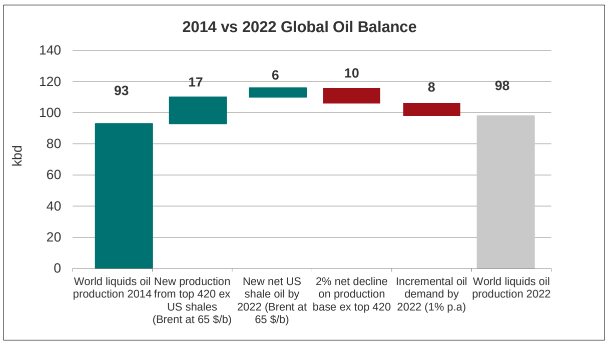
We do however believe that one of the key reasons that we are not able to see the 4% decline in the historical numbers is the fact that in an environment with rising oil prices, operators spend more money on field maintenance than in a weak oil price environment. According to Rystad Energy the peak of global oil & gas upstream investments was reached in 2013 at a massive 900 billion USD. Rystad Energy also estimates that global oil companies will invest 180 billion USD less this year than last year.

In that context it is highly relevant to note that through the whole history of the oil market, going back to 1859, we have never seen such a long period with rising oil prices as what we saw after the change of the millennium. Now as investments and spending is collapsing we do expect a higher decline rate to start materializing. If that does not happen, the market may need a major geopolitical event in order to balance...

If global oil demand increase by 1 million b/d per year and the global decline rate increases from the calculated 1.5% to 2%, the market will need 18 million b/d new oil into the market by 2022.



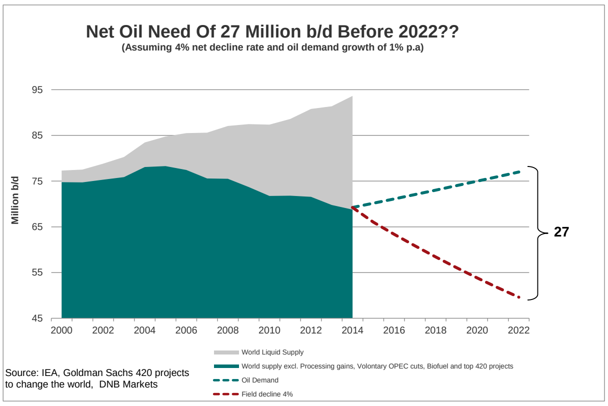
Based on the Goldman Sachs top 420 report, the market should be able to bring on 23 million b/d from just these projects by 2022. In such a scenario, the market is not looking tight at all, even 5-7 years out in time.



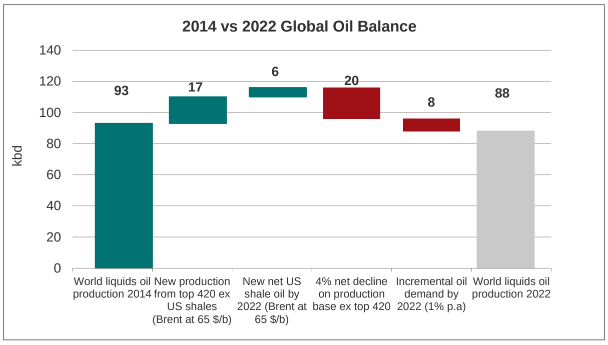
The assumption is then that all the projects that already has the Final Investment Decision (FID) will be carried through no matter the oil price and that only projects with a Brent break-even below 65 $/b will get sanctioned in the years up to 2018.

There are however only 17% of the projects among the top 420 that does not have the FID, meaning we can be fairly certain about most of these projects being executed going forward.

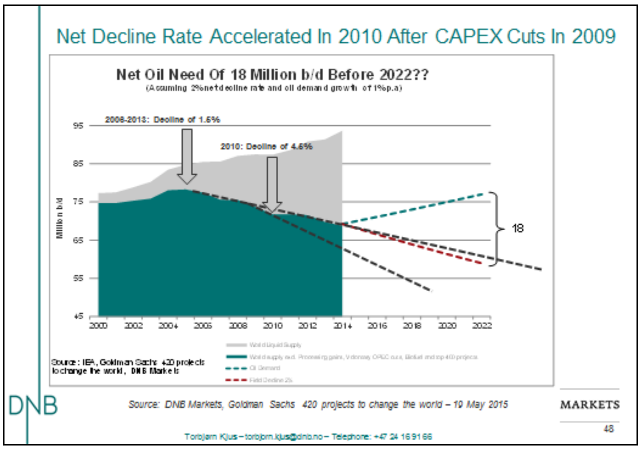
But what if the global decline rate increases to 4% instead of 2% due to the massive cuts in spending?



Well then the situation would be totally different. The market would then need 27 million b/d by 2022 and the top 420 projects would not be enough to cover this requirement. What happens to the decline rate is hence immensely important when it comes to the future oil market balances.

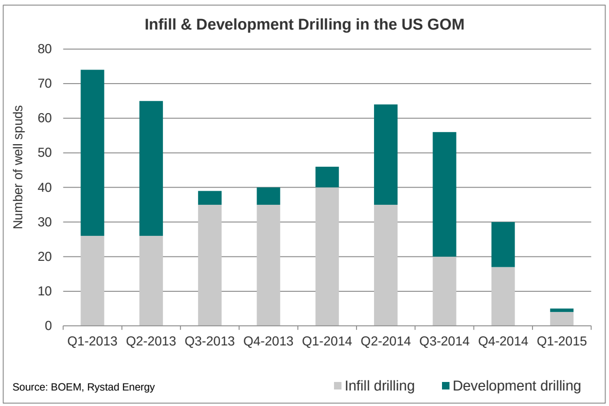


The difference between a decline rate of 2% and a 4% decline rate is by 2022 a large 10 million b/d. Such a decline would be a problem for the market as then more barrels would be needed or alternatively demand growth would have to be lower. Both these factors could be achieved by a higher oil price.

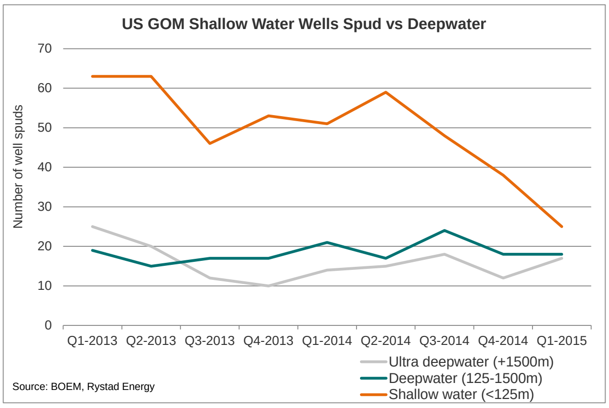


Based on the arguments above it is interesting to note that in 2010 we did see a bump in the calculated decline rate. The calculated decline rate accelerated to 4.5% in 2010. So what happened in 2009? Well in 2009 global investments in the oil industry were cut by 12-13% according to the global oil consultancy IHS. In 2015 global spending in the oil industry is cut by much more than that which suggests that we may start seeing an effect of this during 2016. We are not able to put much hard evidence of this expectation so far, but we have some.

One evidence is the collapse in infill drilling in the US GOM for example. If operators stop doing maintenance on their existing fields (infill drilling for example) then production from those fields will have to decline faster than if the drilling was executed of course.



There is probably also something to be read by the collapse in shallow water wells in the GOM. The shallow water wells are more related to existing production than the deeper water wells.



Based on the above we believe valid arguments exist to expect accelerating field decline rates going forward. The problem is to quantify the acceleration. This is extremely difficult and it will be very important for the oil balance in the coming years. As we have already highlighted there is an immense difference between a net decline rate of 2% and 4%. But in order to be very bullish to oil prices it is probably necessary to believe that the identified decline rate during the past 14 years of 1.5%-1.7% must more than double in the coming years.

One could argue that the lower the oil price trades during the second half of 2015, the better arguments for a higher oil price later as the operator's spending budgets for 2016 and 2017 will be more negatively affected the lower the oil price trades during the autumn.

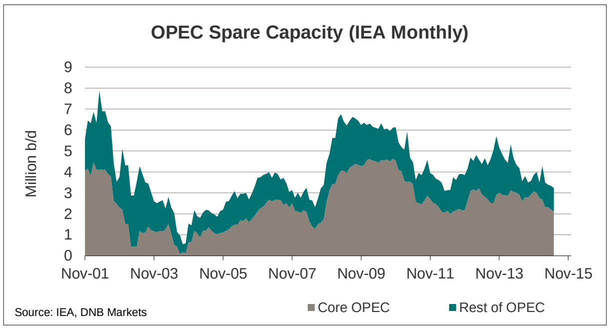
11 Spare capacity

In addition to the expectation of a higher decline rate, the other key bullish argument for oil prices in the coming years is the very low current global spare capacity.

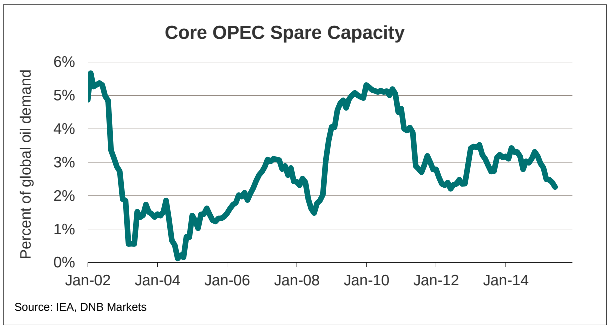
For many years oil analysts have been used to think of the world's spare capacity as OPEC's spare capacity. Historically, non-OPEC has always produced as much as possible with a few expectations of solidarity cuts with OPEC. In 1998-99 Saudi Arabia, Mexico and Venezuela were able to coordinate collective OPEC and non-OPEC cuts with the cooperation from non-OPEC countries like Russia, Norway, Mexico, Egypt, Oman and Yemen. These cuts were however mainly just communicated cuts and not executed in reality. Hence non-OPEC in reality keeps no spare capacity.

There is also historical evidence to suggest that in reality, there are only a few OPEC countries that on purpose keeps spare capacity. This would be the countries that we for brand the "core-OPEC countries". The core OPEC countries are the countries that are ruled by families (Kingdoms) and hence are thinking much more strategic and longer term than the rest of the OPEC countries. Countries like Nigeria and Venezuela are for example not able to think long-term and strategic to the same extent and in reality they keep no spare capacity.

IEA peg OPEC's spare capacity to be 3.2 million b/d in their latest report.

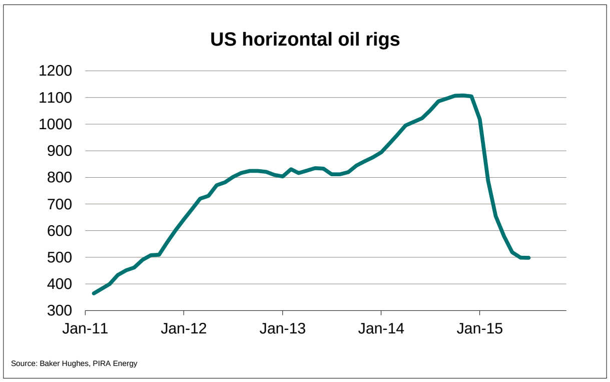


Iran is estimated to hold 0.8 million b/d of spare capacity while Saudi is estimated to hold 2 million b/d. The core OPEC countries (Saudi/UAE/Kuwait) are estimated to hold 2.1 million b/d of spare capacity. This is only 2.3% of global oil demand.



It is of course difficult to find any other global industry that operates with an almost 98% utilization rate. There is very little room for unexpected events in an environment with such low spare capacity. A large outage in Iraq would for example be difficult to cope with in the current situation. Spare capacity is defined by the IEA as the capacity level that can be reached by 90 days and sustained for an extended period. The definition was recently changed from capacity that can be reached within 30 days and sustained for 90 days.

Based on this definition the US oil market holds no voluntary spare capacity except the SPR of course. But we would claim that the massive drop in the rig US rig count nonetheless represents a type of spare capacity which probably means we have to think differently about this issue going forward.



US horizontal oil rigs have dropped by 600 since November last year. Even though many of these rigs will probably never re-enter the market, no matter the oil price,( )-4(y)1TJ-ieov

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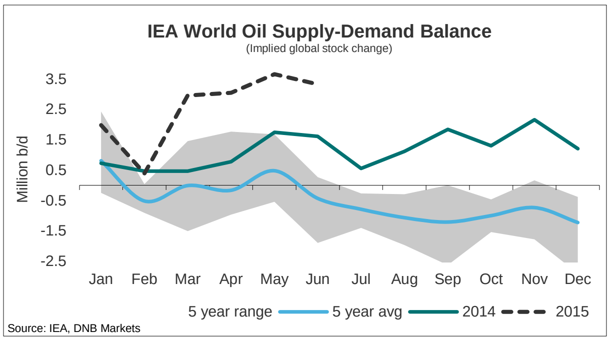
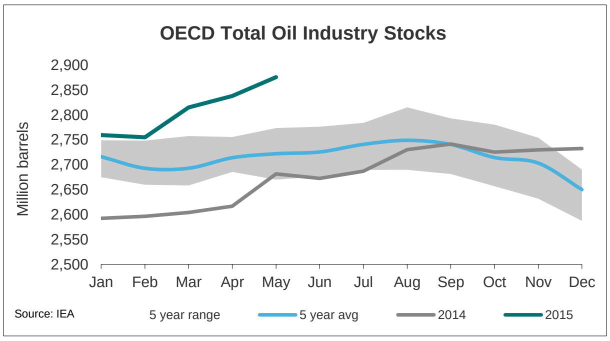
12 Supply/demand balance

Based on the numbers reported by the IEA, the supply demand balance has deteriorated massively during the first half of 2015. The balance shown below is using the monthly numbers for supply and OECD demand and then translating the non-OECD demand numbers over from quarterly to monthly numbers. The numbers are pure from the IEA.

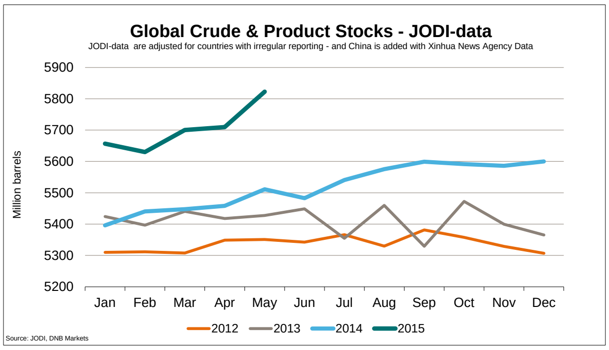


This means that the oversupply estimated by the IEA has been a massive 2.6 million b/d for the first half of 2015. This is consisting of 1.8 million b/d for Q1 and an extraordinary large 3.3 million b/d for Q2. As written under the chapter of missing barrels, there are several analysts who question if the market could really have been that much oversupplied in Q2. Several analysts speculate that demand may be stronger than reported by the IEA.

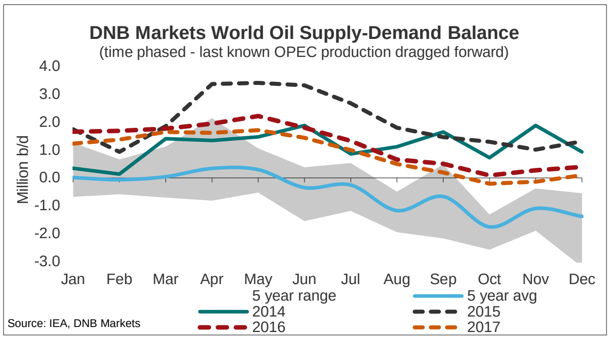
No matter how we twist the numbers however there have been large stock builds associated with this data.



Total OECD stocks are 195 million barrels higher than last year. And if we look at the JODI database, the total global oil stocks are 311 million barrels higher than last year.

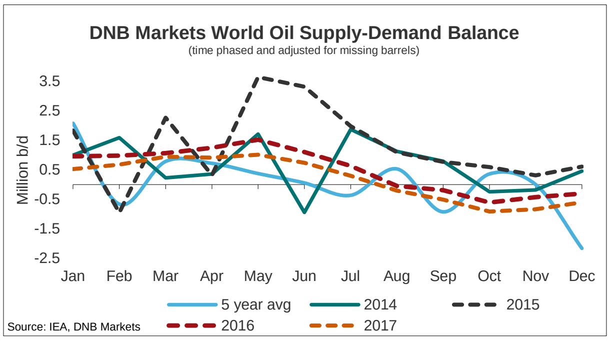


Our forecasted supply-demand balance suggests that the market will stay oversupplied for several years ahead.



As can be seen above the balance is tightening going forward but it is not moving all the way back to a stock draw situation. It is only becoming less slack, or less oversupplied to put it that way.

Even if we assume that the 0.7 million b/d of missing barrels is in fact demand and we continue to add that number to demand going forward, we are not able to come up with a stock draw until the autumn of 2016.

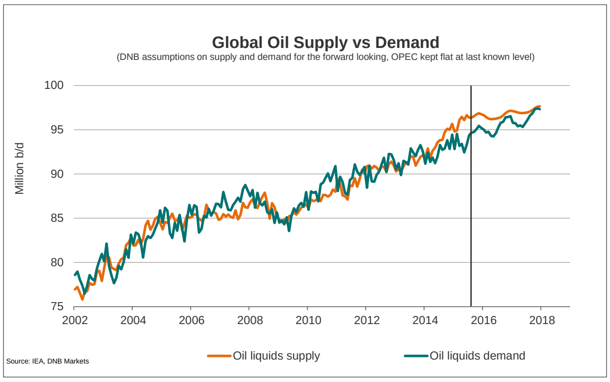


In our forward-looking balance we are assuming demand growth of 1.2 million b/d for 2016 and 0.9 million b/d for 2017. We keep OPEC flat at 31.7 million b/d and assume negative non-OPEC growth in 2016 and only 0.5 million b/d of growth for 2017.

DNB Markets World Oil Supply-Demand Balance:	2015	Change	2016	Change	2017
OECD Demand	46.3	0.3	46.6	0.1	46.7
Non-OECD Demand	47.8	0.9	48.7	0.8	49.6
Total Demand	**94.1**	**1.2**	**95.3**	**0.9**	**96.3**
Non-OPEC Supply	56.0	-0.2	55.8	0.5	56.3
OPEC NGL's and non-conventional oil	6.6	0.1	6.7	0.1	6.9
Global Biofuels	2.2	0.0	2.2	0.0	2.3
Total Non-OPEC supply	**64.9**	**-0.1**	**64.8**	**0.6**	**65.4**
Call on OPEC crude (and stocks)	**29.2**	**1.3**	**30.5**	**0.3**	**30.8**
OPEC Crude Oil Supply	31.3	0.4	31.7	0.0	31.7
Implied World Oil Stock Change	**2.1**		**1.2**		**0.9**

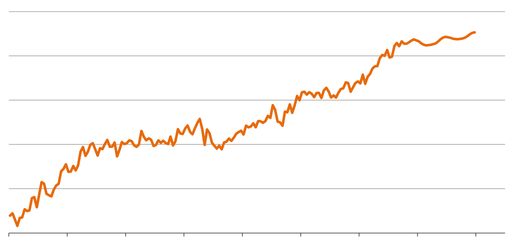
The above numbers means that the “Call on OPEC” increases from 29.2 million b/d in 2015 to 30.5 million b/d in 2016 and to 30.8 million b/d in 2017. An increase of 1.6 million b/d in the “Call on OPEC” during just two years would normally be seen as very bullish. The problem now is however that OPEC is already producing 31.7 million b/d and there are no signs of policy production cuts, as mentioned under the OPEC chapter.

Maybe the situation can be even better illustrated by showing how the global supply-demand picture looks historically and with our assumptions for the next couple of years.



As can be seen above it will take some time to get back to a new equilibrium due to the current massive over supply. Even as the red line (supply) flattens out on the back of lower shale oil growth and as global demand continue to grow, we are still looking at an oversupplied balance.

If we add the missing barrels of 0.7 million b/d to the demand side, the picture is looking more constructive, but we are still not able to reach stock draws in 2016 or 2017. With OPEC flat we will then still see a stock build of 0.5 million b/d and 0.2 million b/d in 2016 and 2017 respectively.



Inside our supply-demand balance we have adjusted all our production growth rates negatively compared with what each country has achieved so far in 2015. This is based on our expectation of accelerating decline rates and the negative effect of the large CAPEX cuts.

Below are some of the key assumptions for the supply side. It is worth highlighting that we have as a base case that Russian production growth will disappear and turn negative during the next two years.

Liquids Supply	Change 2012	Change 2013	Change 2014	2015 YTD Change	Forecast 2015	Forecast 2016	Forecast 2017
Australia	-10	-76	29	-1	-57	-38	-34
Canada	214	260	278	145	95	44	43
Mexico	-24	-32	-91	-242	-218	-178	-168
Norway	-125	-80	58	46	17	1	0
United Kingdom	-169	-63	-19	-21	-37	-59	-54
United States	1,035	1,109	1,661	1,486	904	-201	690
Azerbaijan	-45	6	-26	-18	-17	-16	-17
Kazakhstan	-16	48	-23	35	38	53	54
Russia	81	116	113	128	106	-122	-381
Ghana	4	22	4	5	4	3	3
South Sudan	-215	68	56	-9	-4	0	0
Sudan	-208	-7	2	-14	-13	-11	-10
Malaysia	18	-30	26	98	75	52	56
China	74	2	47	66	67	66	66
Brazil	-44	-35	231	283	202	129	134
Colombia	29	64	-17	30	32	30	32
Oman	30	30	1	21	23	24	25
Syria	-182	-111	-27	-3	-3	-1	-1
Yemen	-52	-40	-5	-84	-47	-10	-9
Sum:	**408**	**1,327**	**2,268**	**1,953**	**1,225**	**-196**	**462**

Instead of growing by more than 100 kbd per year during the past three years we have Russian production falling by 122 kbd in 2016 and another 381 kbd in 2017.

Some would probably see this as quite aggressive, noting that Russian production has so far shown no signs of deteriorating.

Source: IEA, DNB Markets

We do however believe that the weaker Ruble has so far positively affected the Russian oil industry and also the lower exports tax which comes on the back of lower global oil prices. There should also be a lag effect connected with the financial sanctions vs the country's oil industry. There is a point to be made that even with these quite pessimistic assumptions for non-OPEC supply, the global supply-demand balance looks very weak also going forward.

13 Bullish vs Bearish

Bullish arguments:

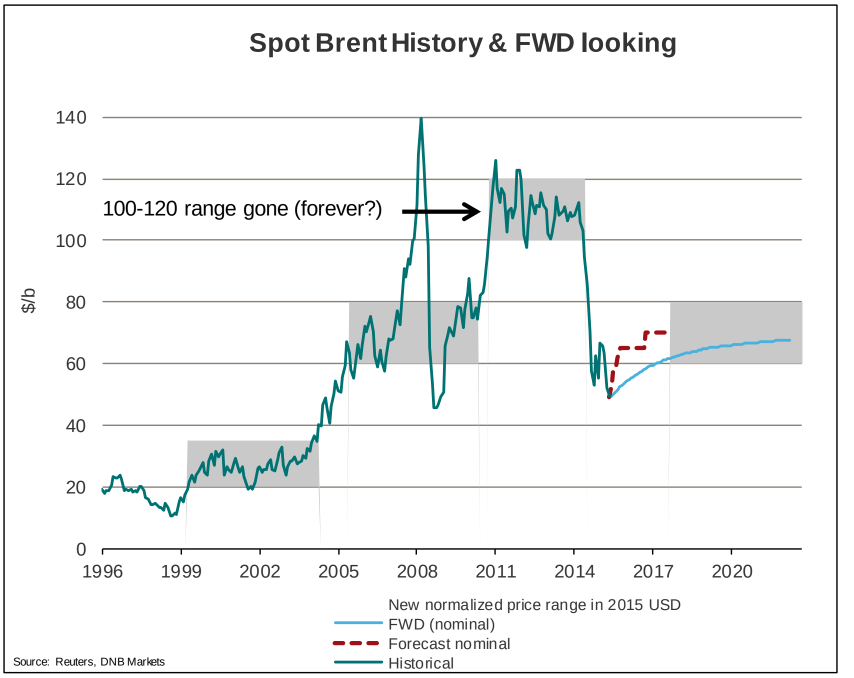
- Large increase in the Call on OPEC for the next two years
- Large cuts in global oil investments and even larger cuts in US shale oil companies
- Rig count in the US has collapsed
- Many US shale oil companies will struggle to get access to capital and several will go bankrupt
- US liquids production growth of 1.6 mbd will turn negative by Q1-2016
- Decline rates set to accelerate already into 2016
- Demand is performing very strongly in US, China and India on lower prices
- Americans driving more and buying more gasoline thirsty vehicles again
- 60 $/b vs 110 $/b is worth almost 1700 billion USD to the global oil importers – Supports better global GDP-growth
- Geopolitical risk in OPEC countries is increasing at low oil prices (and remember we are coming from average 110 $/b)
    - Key risk is Venezuela, Iraq, Nigeria
- OPEC real spare capacity is only 2.3% compared to 17% in the middle of the 1980's
- The market is set to price in better fundamentals before better fundamentals actually materialize

Bearish arguments:

- Massively over supplied supply/demand-balance in 2015, and also in 2016 and 2017 (Less over supply however)
- Global oil stocks are already high and continue to build
- Shale oil resource base looking to be much larger than most people though just a few years ago
    - Shale oil production has only surprised to the upside so far
- Delayed response from drop in rig count to drop in production – High grading of acreage – Productivity improvements
- Financially distressed US shale oil producers are only behind 3% of the US shale oil output
- Global demand growth last ten years protected by subsidies – What now when subsidies are removed in many EM? UEA in July was the first Middle East OPEC member to remove petroleum subsidies
- Saudi Arabia not set to protect a high price – targeting market share instead
- Costs in the global oil industry set to drop significantly – Slack in the service industry as CAPEX is cut
    - The marginal 2-3 million b/d most expensive barrels are set to be cheaper = lower oil price required
- Libya is already out of the market and cannot get much worse – You cannot loose what you don't have
- Iran returning to the market
    - 2016 YoY growth of 500 kbd with a gradual ramp up to 3.5 mbd by 1H-2016

14 Brent forecast

	Historical Nominal $/b	Historical Real (2014) $/b
2001	24.4	32.7
2002	25.0	32.9
2003	28.8	37.1
2004	38.3	48.0
2005	54.5	66.1
2006	65.1	76.5
2007	72.4	82.7
2008	97.3	106.9
2009	61.7	68.1
2010	79.5	86.3
2011	111.3	117.1
2012	111.7	115.1
2013	108.7	110.4
2014	99.5	99.5
	Forecast Nominal $/b	**Forecast Real (2015) $/b**
Q1-15	55	
Q2-15	64	
Q3-15	55	
Q4-15	60	
2015	58	
2016	65	
2017	70	
2018-2022		60-80



Source: Reuters, DNB Markets

15 Global supply vs demand – DNB, IEA, OPEC & EIA

16 Oil price score card for 2016

2016 Oil Price Scorecard	Comments	Oil Price	Weight
Overall Outlook	The market still looks over supplied in 2016 but the call on OPEC is increasing by 1.3 million b/d. The upside is capped by falling production costs, large US spare capacity in the form of available oil rigs and OPECs market share strategy. But OPEC spare capacity is very low and non-OPEC supply growth will fade soon while geopolitical risk is high.	**Average price 65 $/b**	
Fundamentals			
Global Fundamental Balance	The global supply-demand balance is still looking over supplied for 2016, but much less over supplied than in 2015 as the call on OPEC is increasing by 1.3 million b/d. The problem is however that OPEC looks to produce more than the call.	**BEARISH**	**HIGH**
Crude vs Product Balance (Margins)	Refinery margins will probably be weaker in 2016 than in 2015 as particularly the Middle East is bringing on new capacity and as oil demand growth will be weaker in 2016 than in 2015.	BEARISH	MEDIUM
OECD Stock levels	Stock levels are record high and looks to continue to build.	BEARISH	MEDIUM
OPEC Spare Capacity	Core OPEC spare capacity is low at only 2.3% of global oil demand.	BULLISH	MEDIUM
US Oil Statistics - Fundamentals	US oil production growth which was 1.6 million b/d in 2014 and about 0.9 million b/d in 2015 is forecast to drop to slightly negative in 2016.	BULLISH	MEDIUM
Global Demand Growth	Global oil demand growth is positively affected by the lower prices in 2015 but this effect is seen to fade in 2016 as global oil demand growth drops from 1.6 million b/d in 2015 to 1.2 million b/d in 2016.	NEUTRAL	MEDIUM
OPEC Supply	OPEC (Saudi) is seen to contiunue its policy of targeting market share instead of price. And we estimate that Iran will increase its output from the current 2.8 million b/d to about 3.5 million b/d by next summer.	**BEARISH**	**HIGH**
Non-OPEC Supply	Total non-OPEC supply growth is seen slightly negative in 2016, down from a record growth of 2.2 million b/d in 2014.	BULLISH	MEDIUM
Political Risk			
Iraq, Iran, Nigeria, Venezuela, US, Russia, Israel, MENA, etc	Political risk is probably on the rise. Key risk is from countries like Venezuela, Iraq and Libya. The Iran deal will probably bring more OPEC barrels to the market, but generally the sunni-shiite conflict and IS has increased the total risk in the Middle East.	BULLISH	MEDIUM
Other Factors			
Financial Money Flow	Total financial net oil length is close to 40% lower than the record levels for borth NYMEX and ICE London. There is hence room for a rebuild of positions if the sentiment should change. Right now the market probably cannot become much more negative about China, OPEC market shale policy and robust US shale oil.	BULLISH	LOW

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