NACHSPIEL

- CHEAPER OIL BUT NOT CHEAP

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Content

Highlights

- **We maintain our oil price forecast which has remained unchanged since August last year. We still expect 102 $/b for 2014 and 100 $/b for 2015 – and then a gradual decrease in prices to 90 $/b during 2015-2020. We believe the oil price will trade mainly in an 80-100 $/b range after 2015.**

- **We believe a larger supply growth outside of OPEC than what we have seen the last ten years - in combination with lower trend line oil demand growth - will bring oil prices somewhat lower. We do however not believe in a return to cheap oil. This is due to the high cost of bringing the new barrels to the market, rising geopolitical risk and rising global field decline rates, which will materialize if the oil price should fall too much.**

- **Oil's share of the global energy mix is set to continue to decrease in the coming years. The oil age will not end due to a lack of oil just like the Stone Age did not end due to a lack of stones. Technology changes and price incentives are the key words. Why use expensive oil if you can use cheaper natural gas and why drive an inefficient car if you can drive an efficient one? Why develop expensive arctic offshore oil if you instead can develop cheaper shale oil onshore?**

- **The high and rising oil price we have seen since the change of the millennium is starting to initiate structural changes to oil demand through substitution and efficiency improvements. The changes are not as large and fast as we saw after the rising oil price in the 1970's but they are coming none the less.**

- **The US market will retake its position as the most important market for oil price formation the coming 5-6 years. Net US imports of oil has dropped since 2007 but so far the largest switch has been in refined products. The next step is significantly lower crude oil imports. US demand for refined oil products will be trending lower in coming years despite our view that US GDP growth will be stronger than the consensus forecast.**

- **Accelerating oil demand in the non-OECD is not materializing like we earlier predicted it would. Chinese refinery throughput is stalling and Chinese economic growth will be less energy intensive going forward. This is already materializing in 2013. High car sales will not be enough to secure the same level of oil demand growth from China as we have been used to see during the last ten years. Population growth and urbanization will continue to provide energy demand growth in non-OECD but refined products are not going to be the winner in the energy mix market share.**

- **Oil production outside of core-OPEC is growing quicker than global oil demand due to the North American shale oil revolution. It implies that the "call on OPEC" crude oil will be falling in coming years. US crude oil production has increased 1.7 million b/d the last two years. US oil production growth in 2012 surprised more than 2000% to the upside compared with the initial IEA assessment from the summer of 2011. The growth will be somewhat lower in the coming years but still be very high despite large decline rates per well. The resource base looks to be much larger than most people though just a year ago. EIA now says recoverable global shale oil resources are 345 billion barrels, and in that assessment the Middle East and the Caspian region is not even included.**

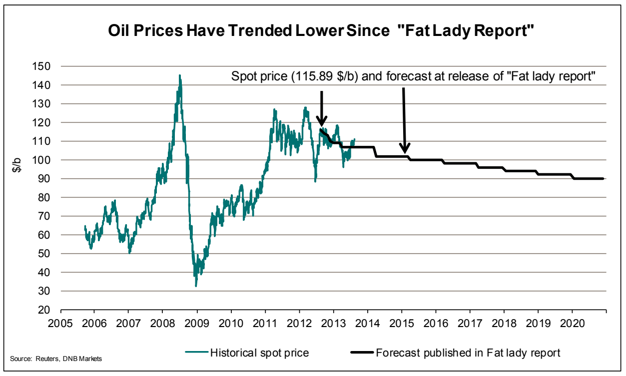
- **Why not a return to cheap oil? The answer is that the costs to bring the new shale oil barrels to the market are high and geopolitical risk in the Middle East will be higher than in the prior ten years due to the Arab Spring. Unplanned outages caused by geopolitical unrest have more than offset the growth in US shale oil production since 2010. Will that continue going forward?**

- **Saudi Arabia is said to soon need a higher oil price than 100 $/b to balance its state budget, but the kingdom does not really need a certain oil price, they need revenues. Their revenues are a function of *both* price and volume. What kind of strategy will Saudi Arabia pursue – market share or price?**

1 Maintaining our forecast

A year has now passed since we issued our report "The fat lady gas started to sing" which created some debate in the Norwegian financial media. As our regular readers will know, we changed our view on the oil market from bullish to bearish last year based on what we believe will be structural technological developments that already have started to affect both supply and demand in the oil market.

During the latest year we have heard people argue that the shale revolution in the US will not be able to push the global oil price lower. Some have said;" with US oil production growing at that enormous pace, why isn't the oil price falling?" Well first of all; instead of trading in a 115-120 $/b range like the Brent-market did for most of 2011 and half of 2012, the market has now found a new and lower trading range. It is also worth mentioning that for the first time in 15 years the Brent market has now closed lower for the third straight quarter.



The average Brent price for 2011 and 2012 was 111 $/b and 112 $/b respectively. The average Brent-price for the first half of 2013 came in at 107.9 $/b while the first half of 2012 the average price was 113.6 $/b, so it is just not correct to claim that oil prices have not fallen. In order to come in higher than last year's 112 $/b we need to see an average Brent-price for the second half of the year of 117 $/b. We think that kind of average price for the second half of 2012 is highly unlikely. We hence believe we are on track to be correct in our statement from last year that the average oil price will start falling already in 2013.

After having been through the longest period of rising prices in the history of oil, with 12 of the last 14 years showing higher prices, the oil price party is coming to an end. We are still confident that the average Brent-price will trade at significantly lower levels the rest of the decade than the 111-112 $/b we saw in 2011-2012. For the 2015-2020 period we believe the most likely trading range will be 80-100 $/b. We would also like to point out that the only reason why the market is not already trading below 100 $/b is that growth in unplanned disruptions to production since 2011 have so far more than offset the growth in US shale production. At the start of 2011 about 0.5 million b/d of global oil production was shut in due to unplanned disruptions (at that stage Nigeria had the largest disruptions). Since then, the global unplanned disruptions have grown to about 3.3 million b/d. The largest disruptions in 2012-2013 have of course been from Iran and in 2011 it was the shut in barrels from Libya that was the key element.

What people need to ask themselves is if the continued growth in shale crude production from the US will continue to be matched by continued growth in unplanned outages. If oil prices are to stay above 100 $/b, we will most likely have to see further growth in outages. It will not be enough to stay at the current 3.3 million b/d shut in barrels. Outages will have to continue to increase in the same pace as shale crude output increase. Is that plausible? Maybe it is more plausible to actually see a return of some of these shut in barrels, rather than just continued increased losses? What happens to oil prices if the shut in barrels from South-Sudan and Iran both return to the market the coming year?

1.1 The Stone Age did not end due to a lack of stones…

Just as the stone-age did not end due to a lack of stones, we do not believe the oil age will end due to a lack of oil. Technology break-through is the key word. During the past 100 years there have been several periods where people have been afraid that the world would run out of oil. Just as an example; look at the quote below from 1919 by Carl Beal, US Bureau of Mines: ""The limit of production in this country is being reached, and although new fields undoubtedly await discovery, ***the yearly output must inevitably decline, because the maintenance of output each year necessitates the drilling of an increasing number of wells. Such an increase becomes impossible after a certain point is reached, not only because of a lack of acreage to be drilled, but because of the great number of wells that will ultimately have to be drilled."*** It is interesting to note that the exact same words are used today by sceptics to further growth in the US shale oil industry.

We should note that in 1919 the United States had produced about 4 billion barrels of crude oil and many were afraid that the country would run out of oil by 1930.

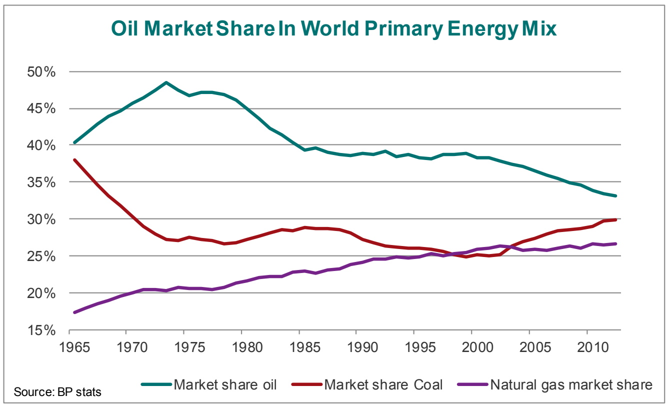
In 1930 the US proved recoverable reserves were 13 billion barrels. How much crude oil did the US produce from 1930 to 1990? The answer is 130 billion barrels, even excluding Alaska. The point is that we think we know something about recoverable oil reserves but in reality we really don't. Recoverable reserves are affected by so much more than just geology. Economics (the oil price in itself), politics (government take) and technology improvements are examples of factors that are equally important as geological factors.

According to the IEA, the global oil recovery factor on the "oil in place" has reached 35%. It will not stop there. This factor is not "written in stone". The improved recovery factors on the Norwegian continental shelf illustrate our point. When Ekofisk started producing, the recovery factor was estimated at 17%. Today the same recovery factor is estimated above 50%. According to the latest BP statistical review, the world's proved oil reserves are 1669 billion barrels. Last year's edition had proved reserves at 1653 billion barrels, so we have seen additions of 16 billion barrels just from last year. Just increasing the global recovery factor by 5% will increase recoverable oil barrels by more than 80 billion barrels. Since 1980 the proven oil reserves have increased from 683 billion barrels to the mentioned 1669 billion barrels. And note that shale oil resources are almost not included at all in this estimate. For the first time we have now this summer seen the US department of energy providing a global estimate of recoverable shale oil resources. The estimate was published in June, and according to the EIA (US Energy Information Administration) the global recoverable shale oil reserves are 345 billion barrels. Note that this is not even including the resources that are probably in place in the Middle East and in the Caspian region. To put it short; we will not be running out of oil the next 20 years either.

2 Global oil demand

2.1 Decreasing market share for oil

The oil market entered the 1970's with extremely strong trend line demand growth for oil. In fact if you exclude the two years 1974-75, global oil demand was growing on average 6.6% per year in the period 1965 to 1979. In the middle of the 1970's, oil's share of the global energy mix reached almost 50%. However in the 1970' the oil price rose in 8 out of 10 years and that brought with it some dramatic effects on oil demand. From 1979 to 1983 the world lost 6.3 million b/d (10% of its oil demand), and oil's share of the global energy mix fell almost 10% to about 39% in 1985. What could unleash such a large drop in the market share? The main reason was of course that oil prices ran away from the prices of other energy sources and people started switching to other sources of energy. The key winners in that period were coal, nuclear and natural gas. Then oil prices fell back from the elevated levels and saw a 15-year period of range bound trading around 17-24 $/b. We had the "mean reversion period", and with stable oil prices we saw a stable oil market share at around 39%. Then oil prices started rising again after the change of the millennium and again the same story repeated itself; oil has been losing market share ever since, and has now dropped to about 33% of the global energy mix. Unfortunately for CO2-emissions it has been coal that has grabbed most of the lost market for oil. Coal's share of the global energy mix has increased by a large 5% to about 30% during the last ten years. If the current trends continue for 5 more years one could claim the *oil age* would be over as oil would no longer be the "king of energy" as it has been for the last 50 years.



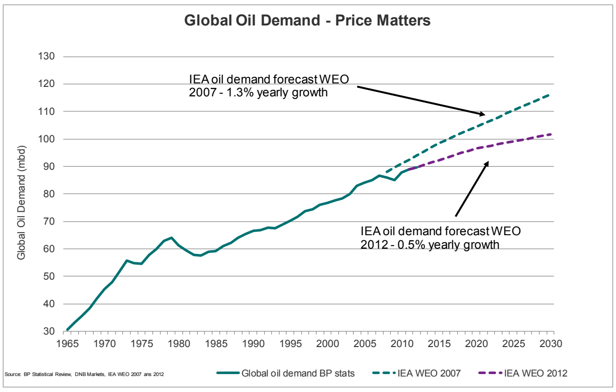
2.2 Trend line oil demand growth did not recover after the 70's

The rising oil prices in the 1970's permanently destroyed the trend line oil demand growth. After the economic recession in the early 1980's was passed, oil demand started growing again, but at a much slower pace than what we had been used to. Since 1984 the average yearly oil demand growth has been 1.5% per year and from 1984 to 2007 the growth was 1.7% - almost linear growth. After the large recession in 2008-09 oil demand has again started growing but the last two years we have only seen 0.9% yearly growth in oil demand and in the first half of 2013 global oil demand is only up 1% vs the same period in 2012.

It is more difficult for high oil prices to destroy oil demand now, than what is was in the 1970's. A much larger share of the oil market was then used in the stationary sector (power generation/industrial production/heating), so it was much easier to initiate substitution to other energy sources. Today, transportation is a lot larger share of the oil market. According to PIRA Energy about 56% of the global oil consumption is for road, air, marine and agricultural transportation, and according to the IEA 94% of all road transportation was from oil in 2008. Because of this we do not believe it will be possible to see as large a decline in oil consumption as we saw into the early 1980's. We do however believe it will be possible to see meaningfully lower growth rates for oil demand than the 1.7% that prevailed from 1984 to 2007. We believe the weaker global oil demand growth we have seen the last couple of years is to large extent unleashed by high oil prices. Oil demand growth in the coming 5-6 years will, in our opinion, most likely continue around 1% rather than the 1.7% that prevailed for almost 25 years.

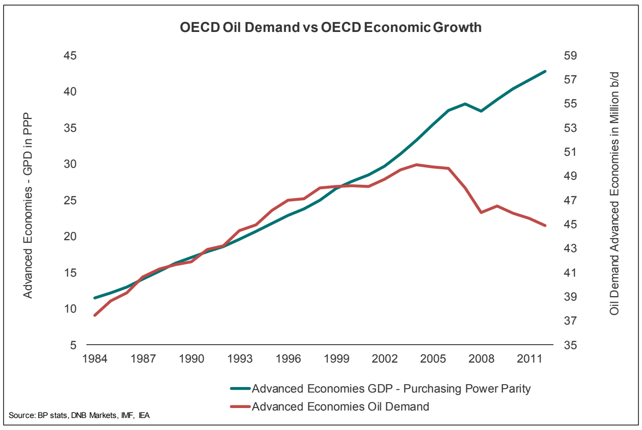
2.3 IEA does not have the answer

It is important to note that the IEA does not have the answer to what is going to happen to oil demand in the coming years. Despite being the most authoritative and used source for what to expect, the IEA is quite consensus driven and will not be the first to spot new trends in any energy markets. As an example: In the IEA World Energy Outlook from 2008 the IEA's reference case for oil demand in 2030 called for about 117 million b/d. In its latest edition from November last year the 2030 reference case is adjusted downwards to about 102 million b/d. In other words; a massive 15 million b/d of 2030 oil demand has been chopped off the last 5 years by the agency.



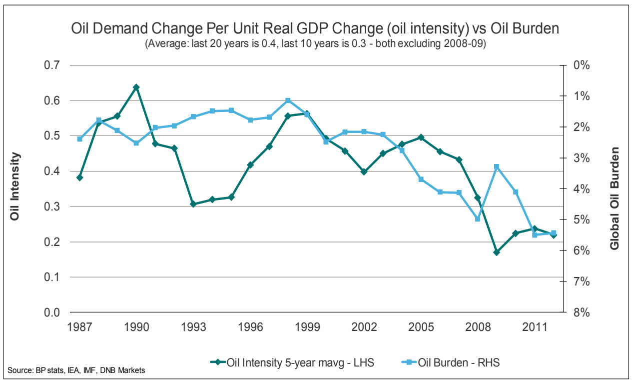
The uncertainty about the IEA forecasts for oil demand can also be illustrated in another way: When the IEA in the summer of 2011 forecasted global oil demand for 2012, the agency called for 91 million b/d. Demand for 2012 is now reported by the IEA to have been 89.9 million b/d. If a demand forecast for the coming year can miss by 1.1 million b/d one can only imagine how incorrect a 10-15 years forecast can become.

One particular issue that has fooled oil analysts since the millennium change is that the relationship between economic growth and oil demand growth in the OECD has broken down. Despite the fact that the OECD economy has continued to increase in size also after the millennium change, the demand for refined products has dropped in the same period by about 3.2 million b/d. We do no longer get any "bang for the buck" with respect to oil demand growth coming on the back of economic growth in the OECD. During the 20 years leading up to the millennium change there was a 98% correlation between the size of the OECD economy (in Purchasing Power Parity) vs the size of demand for refined products. After the millennium change this relationship has broken down and gone negative. A larger size of the economy has not meant more demand for oil but less demand for oil in the OECD. This has a lot to do with the large increase in oil prices we have seen since the change of the millennium. Old models for oil demand that still operate with positive income elasticity's for the OECD will therefore be completely wrong.



Many analysts are also way too focused on how global economic growth will perform when they argue how oil demand will perform. They argue that since global GDP-growth should be at a certain level, then global oil demand should be at a certain level. We have for example seen oil analysts arguing that they expect global GDP-growth to be 3.8% in the coming year and hence oil demand should grow by about 1.9%. This argument is based on the long-term relationship between these two factors, but this is not sophisticated enough. First of all, the correlation between global GDP-growth and global oil demand growth is weaker than many are aware of. Using yearly data since 1986 the correlation is only 32% when we exclude the outlier of 2009 which is the only year with negative global GDP-growth. In 11 out of the 26 years that have passed since 1986 we have seen global oil demand growth in a relatively narrow range from 0.4% to 1% growth, but global GDP growth has for those same years been in a range from 2.2% to 5.3%. Hence when you hear oil analysts claiming that global oil demand will grow by 1.8% next year because global GDP is expected to grow 4%, it is unfortunately not trustworthy, even if the long-term relationship suggest that for each unit of GDP-growth one should get 0.6 units of oil demand growth.

One of the key reasons that the relationship between global GDP vs global oil demand growth is not strong enough to base a model on is to be found in changes to the global oil burden. The global oil burden is the share of the global value creation (GDP) that is spent on oil consumption. When this burden increase the oil intensity is decreasing. The amount of oil demand per unit of GDP growth is decreasing as the oil burden is increasing. Since the change of the millennium the oil burden has increased from about 2% to 5.5% and this has started to provide a negative effect on the oil intensity. Hence a certain level of global GDP-growth is not providing the historical payback with respect to global oil demand growth.



We have since last year argued that the world is going to be surprised by the substitution and efficiency improvements we are going to see in the global transportation sector in the coming 10 years, but we have not tried to quantify these effects. It was hence very interesting to see the analysis from Citigroup that was published earlier this spring which was named “The end is nigh”. The analysis created headlines in the large financial papers and claims that we will see the peak of global oil demand already by 2020. Citigroup estimate that 3.5 million b/d of potential oil demand growth will be replaced by natural gas by 2020. About half of this substitution they claim will be in the transportation sector and the other half will be in power generation, petrochemicals and other sectors. In addition the bank forecasts that efficiency improvements will chop of another 2.5-3 million b/d of demand growth for oil by 2020. The net result will be a peak of global oil demand by 2020 according to Citigroup. We believe these numbers are a bit too aggressive but we think the development will move in the same direction and that the speed will surprise to the upside compared with what consensus currently believe.

2.4 Climate change and oil demand

Several commentators and environmentalists seem to believe that the threat of climate change will lead to a global price of carbon emissions. That increased price on carbon should then be looked upon as a tax that will ultimately be paid by the consumers of carbon, making it more expensive to use oil. A global price on carbon would - all else equal - lead to lower demand for oil, and hence probably lower global oil prices.

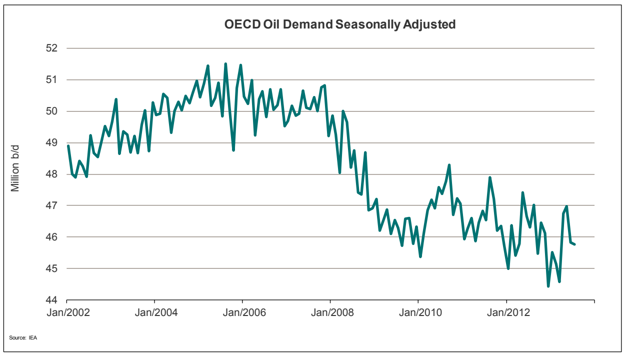
We do however not believe neither China nor the US will be willing to commit to a global price of carbon emissions during the next 5-7 years either. It is probably seen as too risky for the economic growth prospects and for the competitiveness of the businesses belonging in those two countries. We are also convinced that unless both the US and China commit to a scheme that can provide a global price for CO2-emissions, there will be no such global price. And unless there is a global price for such emissions there is no solution to this problem. After all CO2-emissions is a global problem and challenge - not regional. It will require a global solution. As we have stated before, we believe all politics is local politics. Number one for any politician (or country leader) is to get re-elected (or alternatively for a country without elections, to stay in power). It will require economic sacrifices for some businesses to limit CO2-emissions. How will politicians dear to push such sacrifices onto businesses belonging in their own country in today’s economic environment with fragile economic growth and where growth in China is starting to loose pace?

We think the most likely scenario would be that the world leaders continue the same path as before. The next UN climate change conference, which will be the 19th conference where the world’s leaders will gather to discuss the climate change issue, will be in Warsaw from 11-22 November this year. The last one was in Doha in November 2012. We hope that we are not right, but we predict that this year’s conference, like the preceding ones, will agree to sign a pledge to hold another meeting to consider changing course at a date yet to be determined…

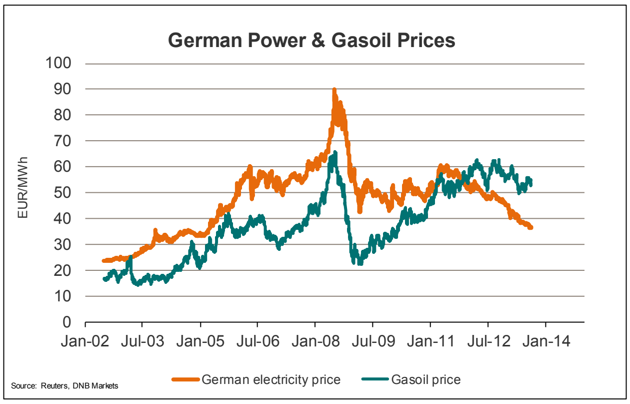
3 OECD oil demand

3.1 OECD oil demand has peaked

Oil demand growth in the OECD has already suffered on the rising oil prices we have seen since the change of the millennium. According to data from the IEA, OECD oil demand is down about 10% since the peak levels we saw in 2005-06.

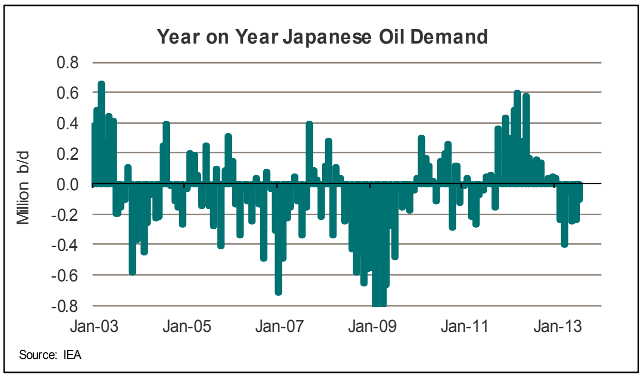


We argue that a good chunk of these lost barrels are caused by structural effects. The lost oil demand is not only caused by a cyclical weak economy in our opinion. Unfortunately the IEA does not split out oil demand by sector on a timely basis, but the agency provides demand per refined product on a monthly basis. This is helpful because some of the product categories in the OECD are quite "clean" when it comes to which kind of sector they serve. The "cleanest" product category is probably "Other Gasoil". In the US it would be labelled "Heating Oil" but in Europe and by the IEA, the classification is "Other Gasoil". This type of oil usage is down 1.9 million b/d since 2005. Total oil demand in the OECD is down 4.5 million b/d in the same period. Germany is the largest gasoil market in Europe. In Germany we have seen electricity prices below gasoil prices since late 2011 due to cheap coal, low carbon prices and a large increase in renewables in the German electricity mix. Why would industries, who can rather use electric boilers for heating, continue to use gasoil if electricity is much cheaper? And why would Germans continue to use gasoil to heat their homes if electricity and natural gas is much cheaper?



Gasoline demand is reduced by 1.0 million b/d since 2005 in the OECD and not all this reduction is cyclical either. There have been on-going efficiency improvements in particularly the European transportation sector. According to the consultancy JBC, European oil demand for transportation would have been 1 million b/d higher now than 10 years ago without a 20% improvement in efficiency. Efficiency improvements in the European transportation sector continue and BMWs new X5-model is probably a good sign post of the market focus on efficiency. What is BMW doing with the engine size in its new X5? The answer is they are reducing the engine size and the new model is said to run on 0.47 litre/10 km. The above makes us confident that even if the growth in the OECD economy should surprise massively to the upside, peak oil demand in the OECD has already happened.

In Japan, the positive boost to year-on-year oil demand due to its shut down nuclear industry is about to fade as we have started comparing with a period where the nuclear facilities were already shut down. We are now seeing negative oil demand growth again in Japan. Most of the Japanese people we talk to about this issue say it is plausible to expect about 50% of the reactors to restart over the coming couple of years. If this happens it implies that the potential oil demand growth that may be coming from "Abenomics" will be more than offset by the reduced demand for oil that will follow from a restart of nuclear reactors. One could also argue that the 30% devaluation of the Yen, which has followed as a consequence of the "Abenomics", is an argument for a quicker restart of nuclear power in Japan. This is due to the fact that Japan basically imports all its consumption of oil. A 30% devaluation of Japans currency hence increases the country's imports bill of petroleum products and crude oil by about 50 billion USD annually.

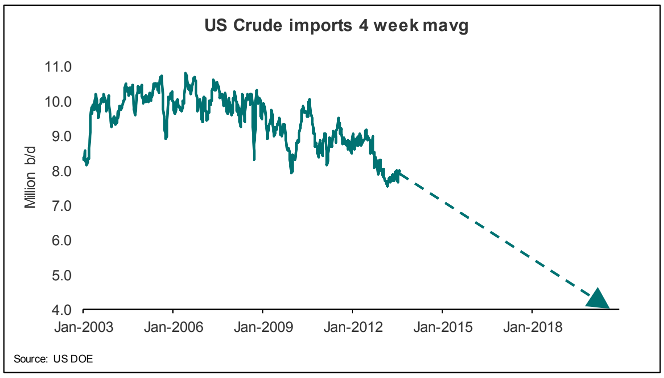


Europe is still struggling with the extremely high debt levels in key countries and the austerity measures that will have to be maintained for a long time period. These measures brings with it still growing unemployment rates in Europe. The poor European economic development together with continued efficiency improvements has pulled down European oil demand from about 16 million b/d to now about 13.5 million b/d. In our opinion it is more likely that we will see this number dropping towards 12 million b/d before it flattens out. Demand for oil keeps on dropping in UK, Spain and Italy. Also in Germany, demand for oil is down year to date in 2013 and in 2012 German oil demand fell by 10 kbd.

3.2 The US is recovering from its oil overdose

US oil demand increased in 2010 after the 2008-09 economic recession, but has since 2011 again started to trend lower. Going forward we expect this downward trend for oil consumption in the world's largest oil consumer (by far) to continue. Demand for refined products in the US will head lower on a combination of both substitution effects (mainly natural gas for oil), and by meaningful efficiency improvements starting to kick into the US transportation sector.

For the oil price discovery the last ten years, China has been the most important factor. We believe that for the coming ten years, the US will regain its throne as the most important market for the global oil price discovery. Barack Obama is the first US president since Richard Nixon who has seen a reduced imports dependence of petroleum. The US used to net import 13 million b/d of crude oil and refined products in 2007. Now this number has fallen to 6.5-7.5 million b/d. So far the largest swing has come from imports of refined products. The US net imported about 2.5 million b/d of refined products in 2007 while in 2012 and 2013 the country has at times net exported more than 1 million b/d of refined products. The imports of crude oil have also started to decrease but there is still much more to be reduced in the coming 5-6 years. In 2007 the US steadily imported more than 10 million b/d of crude oil. Also as late as in the summer of 2010 the imports of crude oil to the US surpassed 10 million b/d. Since then the crude imports into the US has however trended lower. It looked to stabilize at around 9 million b/d from the middle of 2011 to the middle of 2012, but has since fallen to below 8 million b/d. Our prediction is that the net imports of crude oil into the US will have fallen to below 4 million b/d by 2020.

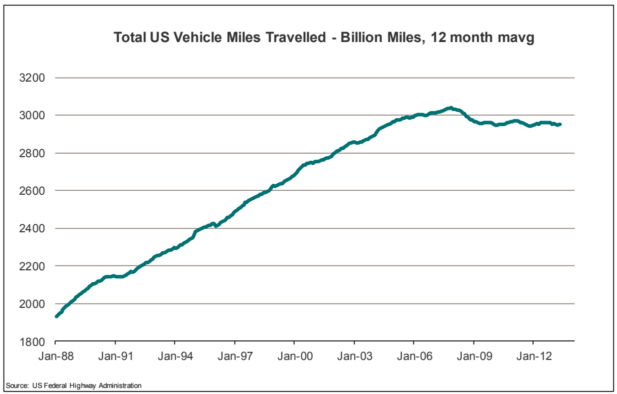


If this happens it implies that more than 4 million b/d of crude oil will be available to other regions of the world by 2020. Crude oil prices in the US will have to reflect that it is not necessary to price to attract imports any more. This means lower US crude prices. Brent-prices will probably often price above Louisiana Light Sweet (LLS) to make sure that West-African barrels are not headed for the US Gulf Coast. Generally easier access to crude should translate into lower international oil prices in the coming 5-6 years.

Let us look at the US demand side first - then we will move over to supply afterwards. US gasoline demand is the largest single chunk of the global oil market. It is about the same size as total Chinese demand for oil and it is about half of US demand for oil. US gasoline demand peaked at 9.6 million b/d in July 2007 and has trended lower ever since. As we moved into the new millennium it looked like a "no-brainer" that US gasoline demand would surpass the 10 million b/d mark by 2013. But in our view US gasoline demand will never reach the mile-stone of 10 million b/d. Instead it will continue to trend lower on a combination of efficiency improvements, changed driving habits and gradual substitution effects.

3.3 Why no recovery in VMT?

It is interesting to note that total US Vehicle Miles Driven (VMT) continue to trend lower, despite continued population growth in the US. The key driver behind an increase in the car fleet is of course population growth, and the population in the US continue to increase by about 0.8% per annum. Why then is the total VMT trending lower?

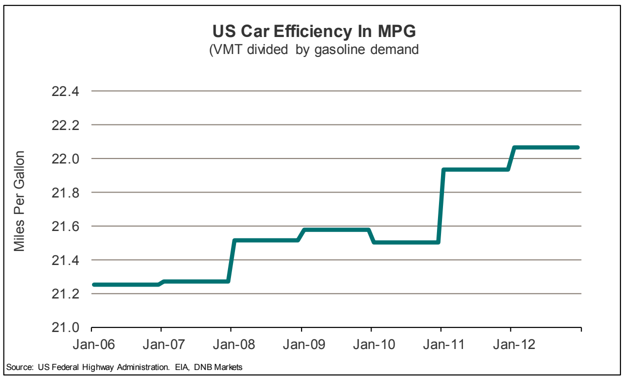


Disposable income per capita has not improved since the recession and that can explain parts of it, but the total VMT has still under performed. We believe the key explanation has to do with structural changes to driving habits in the US population. First of all the "baby-boomers" (people born during the demographic post-World War II baby boom) are approaching an age where people normally start to drive a lot less. According to the University of Michigan Transportation Research Institute, the percentage of people with a drivers licence who are 70 years of age or older has increased from 55% in 1983 to 80% in 2010. Empirical data shows that when people surpass 50 years of age they start driving less. Older adults are no longer burdened with work related and child-serving travel. Health and stamina levels are decreasing with age and hence also general activity levels which correlate with driving.

Maybe even more important are the shifts we are starting to see among younger drivers. 25 years ago young people between the ages of 21-34 used to buy 38% of all the new vehicles sold in the US. This has changed dramatically since then and now these young people only buy 27% of the new cars sold. Interestingly the share of American 19-year-olds without a driver licence has increased from 12.7% in 1983 to more than 30% in 2010. Sceptics will say that a weak economy and hence the increased burden of student loans is to blame but according to Michael Sivak, a research professor at the University of Michigan Transportation Research Institute, the main "culprit" is nearly constant access to the internet and the rise of social media use. In other words, this looks like a structural shift rather than a cyclical one. Sivak said he found similar trends in seven other countries where teenagers have easy access to social media.

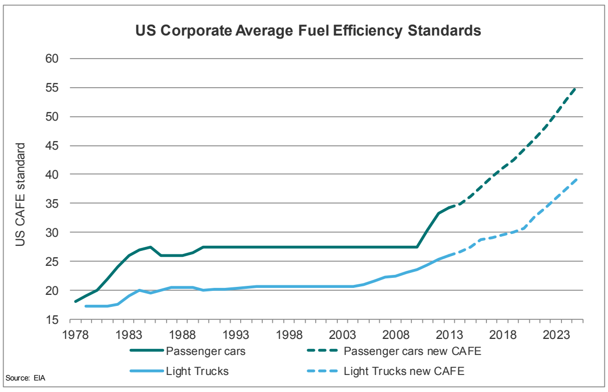
3.4 Efficiency improvements

Not only has the growth in total Vehicle Miles Driven stalled in the US, in addition the car fleet is on average using fewer and fewer gallons per miles driven. For the first time we are now starting to see really meaningful efficiency improvements kicking in for the US automobile fleet.



And what we have seen so far is just a tiny start of what is going to happen within the coming 10-12 years. The Obama administration has the last couple of years imposed new driving standards for the US car fleet which will require US car manufacturers to produce 60% more efficient cars by 2025. The so called Corporate Average Fuel Efficiency (CAFÉ) standard is set to improve from about 30 Miles Per Gallon (MPG) in 2013 to 48.7 MPG by 2025 and this time the Sport Utility Vehicles (SUVs) are not getting off the hook although the requirements are not as tough as for passenger cars.

National Highway Traffic Safety Administration (NHTSA) has established two phases of CAFE standards for passenger cars and light-duty trucks. The first phase, covering model years 2017 through 2021, includes final standards that NHTSA estimates will result in a fleet-wide average of 40.3 MPG for light-duty vehicles in model year 2021. The second phase, covering model years 2022 through 2025 will lead to a fleet-wide average of 48.7 MPG for light-duty vehicles in model year 2025. Compliance with CO2 emission and CAFE standards is calculated only after final model year vehicle production, with fleet-wide light-duty vehicle standards representing averages based on the sales volume of passenger cars and light-duty trucks for a given year. Because sales volumes are not known until after the end of the model year, EPA and NHTSA estimate future fuel economy based on the projected sales volumes of passenger cars and light-duty trucks.

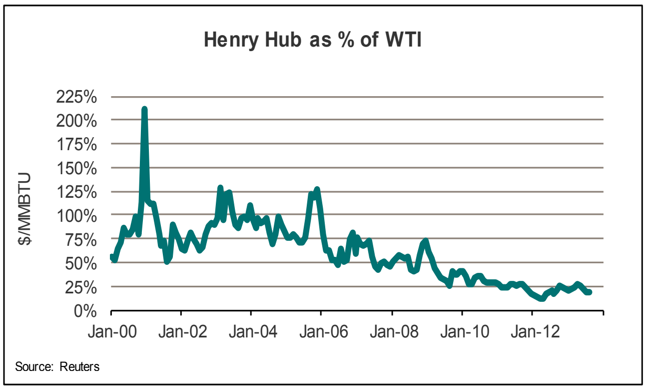


The CO2 emissions and CAFE standards also include flexibility provisions for compliance by individual manufacturers. Examples are: credit averaging (which allows credit transfers between a manufacturer's passenger car and light-duty truck fleets); credit Banking (which allows manufacturers to "carry forward" credits earned from exceeding the standards in earlier model years and to "carry back" credits earned in later model years to offset shortfalls in earlier model years); credit trading between manufacturers who exceed their standards, etc. Flexibility provisions do however not allow domestic passenger cars to deviate significantly from annual fuel economy targets.

If the US car manufacturers comply linearly with these new driving standards in the coming 12 years, US gasoline demand could decrease from about 8.7 million b/d in 2013 to about 7 million b/d by 2025, even assuming a 10 percent larger total car fleet by 2025 (based on population growth). Our point is not to calculate what the exact number is going to be but rather to argue that US gasoline demand will trend lower, even if US economic growth should surprise to the upside in coming years.

3.5 Oil to Gas substitution

In addition to demographic changes, technological changes and efficiency improvements, we now for the first time see possibilities and meaningful economic incentives to substitute away from petroleum usage in the US transportation sector. Because of the US shale gas revolution, the price of natural gas in the US has "collapsed" and currently trades below 25% of crude oil prices and has done so for about two years now.



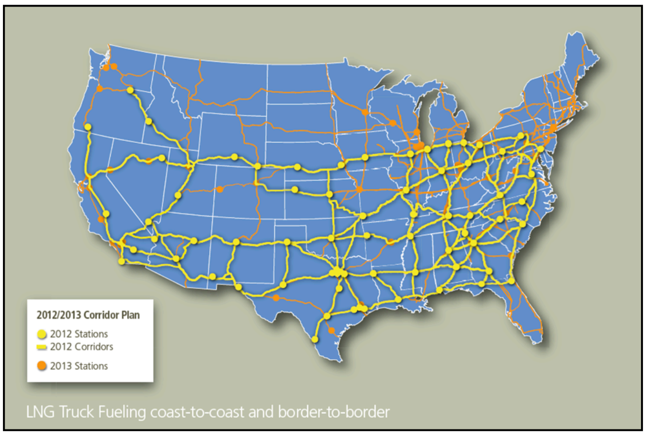
This enormous price differential is of course providing large economic incentives to switch over from oil to natural gas usage if you can. The economic incentive to switch has now been in place for long enough to see large players start investing in the price spread. For the first time we are in 2013 seeing duel fuel cars on the road that are able to run on both gasoline and on natural gas, produced from the factory and not in retro fittings. Several car manufacturers are offering such vehicles for the first time now in 2013. Light trucks and smaller vehicles will mainly be running on CNG (Compressed natural Gas) rather than LNG (Liquefied Natural Gas) which is more for the longer-haul trucking sector. It costs a lot less to build filling stations for CNG than for LNG and LNG-vehicles require equipment to keep the natural gas cold in order to keep it liquid. Hence LNG is so far mainly expected to be used in longer-haul trucking.

We do not expect a meaningful substitution from gasoline over to CNG usage among vehicles used for personal transportation in the coming 5 years. This is due to a need to build an enormous amount of filling stations and due to the fact that the economic incentive for switching is weaker for the personal consumer space than in the business life. After all the average American only spend a small share (maybe 5-6 %) of his disposable income on gasoline, so for most people the gasoline price is not really make or break for the personal budget. It is much more of a psychological issue that can change over time as one gets used to higher prices. The trucking sector is however highly connected to business activities and the price of fuel is a large part of running a transportation business. If you can switch to a fuel that is half the price it will be highly relevant for a transportation company to do so. We hence believe that the largest changes and substitution effects from petroleum over to natural gas in the transportation sector will be from diesel over to LNG/CNG rather than from gasoline. According to calculations by PIRA Energy, a transportation company will save about 40.000 USD per year on fuel per truck by moving over to LNG if the price for diesel is 4 $/gallon and Henry Hub natural gas prices are 4-5 $/MMBTU. This assumes a yearly driving distance of 120.000 miles and fuel efficiency of 6 miles per gallon. By using the new 11.9 litre LNG-engine from Westport-Cummings, PIRA estimate that the 40.000 USD extra investment cost for acquiring an LNG truck is earned back within a year's driving. That must classify as quite compelling economics.

On highway diesel demand in the US is about 2.4 million b/d and most of this is used in the trucking sector to move goods around in the US. In addition the railroads are using about 230 kbd of diesel. There is hence a large opportunity to reduce diesel demand and rather use natural gas in these sectors and we expect meaningful numbers on this arena even before 2020.

The momentum in the US trucking sector to switch over to natural gas from diesel is accelerating. The news flow the last year has been extremely strong on improvements in infrastructure, vehicles, fleets, and liquefaction capacities. In fact it is already possible to drive coast to coast using an LNG truck in the US on Clean Energy's "America's Natural Gas Highway" - LNG trucking corridor. Other players are now coming into this sector as well. ENN Group Co Ltd, one of China's largest private companies, plans to build 50 LNG filling stations in the US in 2013 alone, and last year Royal Dutch Shell revealed that the company will invest 300 million USD in building 200 LNG pumps at 100 locations in the US. Another very interesting piece of news came earlier this year on March 27 when Royal Dutch Shell and Volvo Trucks announced a global LNG fuel collaboration. Why is Shell doing this? Shell is an oil company, is it not? Well, the interesting answer here is that for the first time in Shell's more than 100-year old history, the company is now producing more natural gas than oil. In other words, the company has an incentive to create a larger market for natural gas. With its long experience as a distributor, Shell is the perfect player to take the LNG-industry a step further and open up new markets for this fuel.

The interesting issue here is that since the heavy-duty trucks manly travel along the interstate highways the infrastructure need is really not that large to cover the need for this sector. Instead of talking about 175.000 gasoline stations (the number of gasoline stations in the US by December 2012) we only need about 1000-1200 LNG filling stations to cover most of the infrastructure need. Note that about 200-250 LNG filling stations are set to be in place already by 2013-14, so these changes are already taking place as we write.



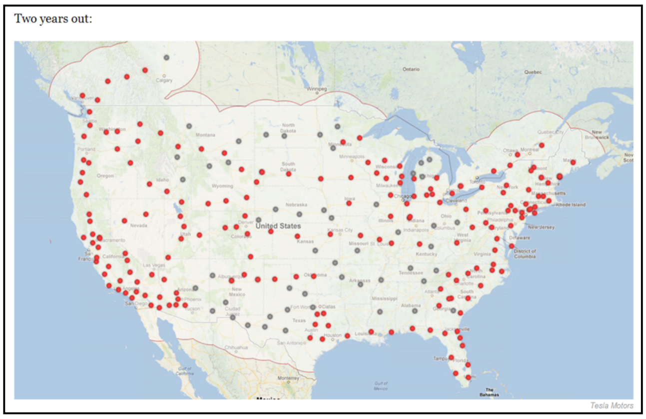
Source: Clean Energy

A good example of the momentum in natural gas for transportation is the refuse trucking sector (garbage trucks). There are about 180.000 such trucks in the US and currently 40-50% of new orders for refuse trucks are NGVs. Another good example is that a BNSF railway, which is the second largest user of diesel in the US, will test LNG-fuelled locomotives in 2013.

We are focusing on the US market for substitution possibilities from oil to natural gas, but the US is not the only market in the world where we expect growth in NGVs. In 2011 there were about 16 million NGVs in the world and the global fleet has according to Citi Research increased by 25% per year the last ten years. If the global growth in NGVs continues at 20% until 2020, the lost demand for oil from these vehicles will be about 2 million b/d by that time according to Citi Research. The largest countries for NGVs in 2011 were Iran, Pakistan, Argentina, Brazil and India. Both United States and China were quite insignificant in 2011, but by 2020 we expect these two countries to dominate the NGV statistics.

3.6 Electric cars

So far electrical vehicles have not made any meaningful impact in the transportation sector. Battery technology has been to weak and electrical cars have not really been cars, but rather some futuristic looking strange small wagons, not able to transport a family and not able to run long enough without charging to be interesting for most people. None of the large car manufacturers have put any effort into this segment. This is about to change in 2013, and the key player unleashing this change is Tesla. In July the new Tesla Model S earned the highest score ever for a car in the Consumer report magazine – 99 out of 100 points. This is a real car that can move you and your family more than 200 miles before recharging. This implies that this car will cover the daily driving need for most people. On May 30, Tesla launched a commitment to expand the number of charging stations in the US to cover the whole country within the next two years.

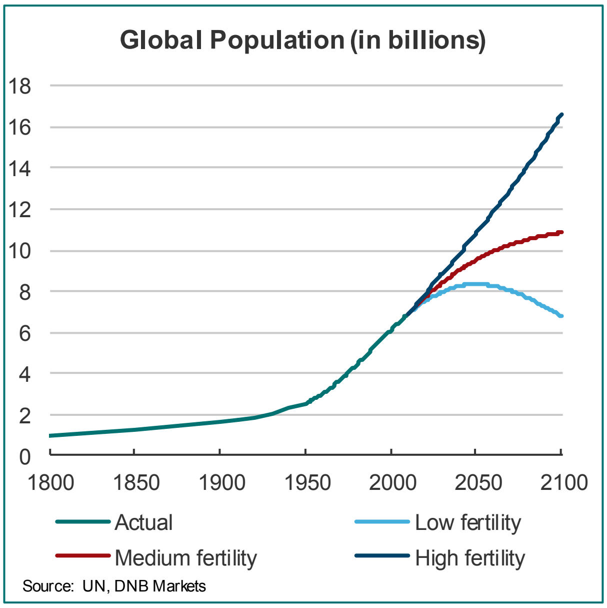


Source: Tesla

Already by the end of 2013 Tesla promise its customers to be able to drive from Los Angeles to New York using its stations. And the really sweet part of this story is that you will be able to charge for free on all these stations. You can, in other words, by the end of 2015 drive through the whole of the US for free. It will take only 20 minutes to recharge the car's battery to two-thirds of the capacity so it does not require you to stay overnight at every pit stop. This development must be scary to watch for the large car manufacturers and yes, now in 2013 we are seeing the large players entering this arena as well. Nissan has already launched its Leaf and BMW, Volkswagen and Ford are all launching electrical cars in 2013. Volkswagen will launch the WW Golf blue-e-motion by the end of 2013, BWW its i3 and Ford its Ford Focus. These cars will be competitors to the Nissan Leaf. We are not claiming that electrical cars will substitute a meaningful volume of gasoline usage during the coming 2-3 years but in a ten-year perspective it is very promising what Tesla is doing right now and it will be exciting to watch if the large manufacturers will be able to come up with competition to the new tesla Model S in the coming couple of years. For now we believe the largest substitution from oil to "something else" in the transportation sector in the current decade will be natural gas usage in the trucking sector.

4 Non-OECD oil demand

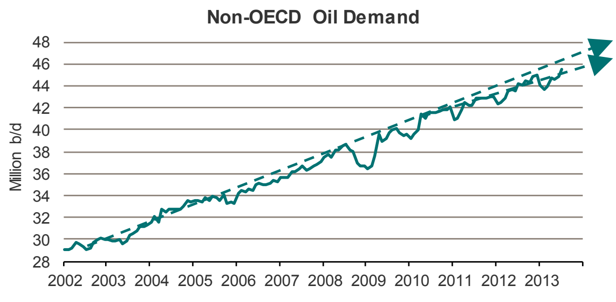
We have argued that OECD oil demand will continue to decrease in the coming years, but this does not mean that we believe global oil demand will start to decrease by 2020. Non-OECD oil demand has now reached 50% of the global market share and we do not believe the mega trends that have been driving this growth in oil demand has run their whole course just yet. If you take a look at where people live in this world, you will see that 60% of the world lives in Asia. In Asia people have the last 10-15 years been lifted from poverty towards the middle class. This of course creates extra demand for energy. At the same time we have seen continued urbanization. Half of the world now lives in cities and most forecasters including the UN believe that this trend will continue going forward. The UN expects the global population to continue to grow at least until 2050.



Source: UN, DNB Markets

In its three scenarios for the world population the UN see the population in the range between 8-10 billion people by 2040 and global urbanization is set to surpass 60% by 2030, from the current 50% level. Population growth creates - almost by definition - economic growth and hence increased demand for energy. Population growth does not necessarily create increased economic growth or energy demand growth per capita. Urbanization is however doing exactly that. It contributes to both economic growth per capita and energy demand growth per capita.

We believe the above mentioned mega trends of urbanization and population growth will continue at least until 2020 and as such will contribute to further energy demand growth in the non-OECD. Energy demand growth is however not the same as growth in demand for refined oil products. We know that some have misunderstood us on this point earlier. We believe in further strong global demand growth for energy based on the above factors, but unfortunately for oil prices we do not believe demand growth for refined oil products will be the winner in the energy mix for the coming 5-10 years. When we were bullish to medium term oil prices (until April 2012) we used to argue that the world should expect to see accelerating oil demand per capita in the developing countries as the middle class keeps growing (GDP/Capita reach certain levels). We have seen that happening in several Asian countries before. The problem is however that we are seeing no signs of accelerating oil demand growth in the non-OECD in the reported IEA-data so far. The accelerating demand trend based on a growing middle class might be evident for general energy demand, but it is just not there for oil.

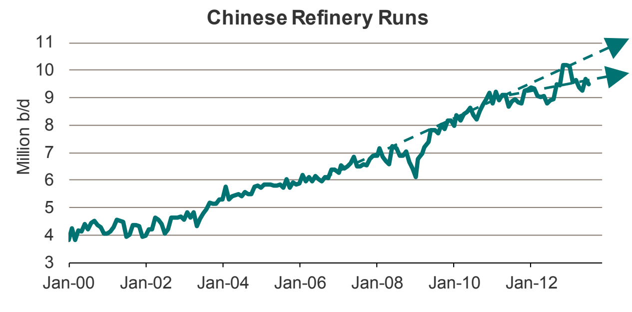


Source: IEA

In fact, when we look at the reported non-OECD oil demand data for the last ten years it looks like the opposite is taking place. The last couple of years it looks as if trend line oil demand growth is faltering. The growth is still very decent, it is just weaker than what we had become used to see. Instead of growing in a range from 4-8% per year, like we saw for most of the 2003-2010-period, the non-OECD growth in oil demand has been more in the 3-4% range since 2011. We have heard arguments that oil demand growth in non-OECD is more resilient vs price levels than many think, as oil prices have quadrupled since 2003 and non-OECD oil demand growth has still grown 4-8% per year. The flaw in this argument is however that most non-OECD countries subsidize end-user oil prices through the state budget, and hence the end user price has not really changed that much for most people in the non-OECD. The analysis on price sensitivity in the non-OECD cannot use global crude prices as the basis for the calculation. When global oil prices increase too high many of these non-OECD countries can no longer afford to continue to support their population with subsidized oil product prices. What happens to the end-user demand then? Could it be that oil demand growth would weaken? It has really not been fully tested yet, but we are seeing some countries scaling back subsidies and then it becomes possible for those countries to look at price sensitivities.

4.1 Chinese oil demand

China has, as most of our readers would know, been the largest contributor to global oil demand growth the last ten years. More than 40% of the 11.2 million b/d of global oil demand growth that has happened from 2002 to 2012 has come from China. Chinese oil demand growth has however shown some weakness the last couple of years. The country's crude throughputs have doubled from 4.5 million b/d in 2002 to about 9 million b/d by 2011. If the trend line growth in crude oil throughputs had continued we should now in 2013 see crude throughputs stabilizing solidly above 10 million b/d. Instead the average crude throughputs in China are 9.6 million b/d for the first seven months of 2013.



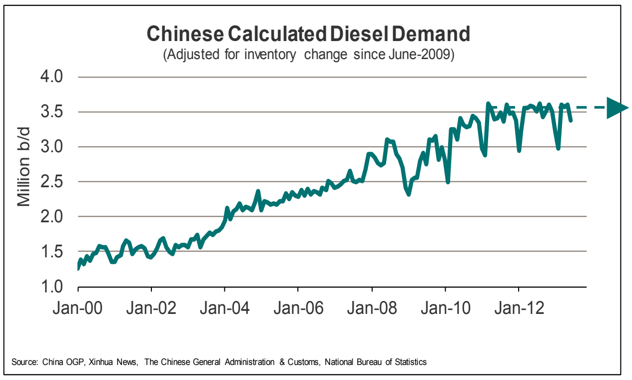
Source: China OGP, Xinhua News, The Chinese General Administration & Customs, National Bureau of Statistics

This stalling refinery throughput of crude oil is even happening as Chinese refining capacity is supposed to expand by about 900 kbd in 2012-13 according to the IEA Medium Term Oil Market Report. What is happening? Well, first of all the increase in refining capacity has not led to the same increase in total refinery throughput so far. Simple so called "tea pot" refineries which is still 15-20% of Chinese refining capacity have probably scaled back their throughput as more sophisticated refineries have come on stream. In addition we have seen a gradual increase in exports of both diesel and gasoline out of China the last year and stocks of refined products suddenly built counter seasonally in China now in June. We have read that Chinese exporters of refined products ran out of export quotas in May-June and hence they were probably forced to counter seasonally build inventory instead of exporting until they can expand their export quotas. Neither growing export of the key refined products nor counter seasonal stock builds are bullish signs of oil demand growth in China.

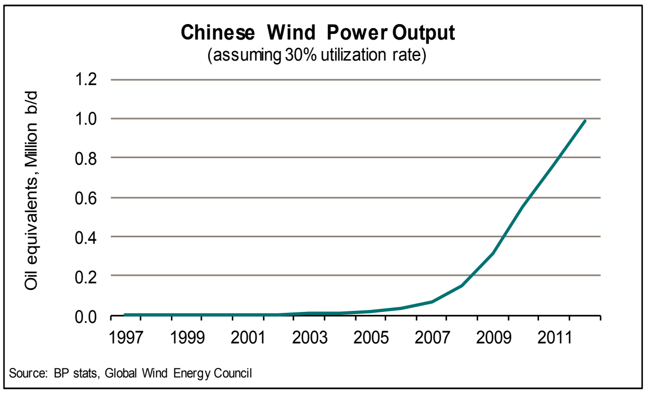
We wrote last year that we expected Chinese economic growth to decrease from its 10% plus that we had seen for the prior ten years into the 7-8% level in coming years. The growth in investments were an unsustainably high share of the economic growth and sooner or later a country will run out of good economic projects and start building bridges, houses and infrastructure that it does not need. More of China's economic growth must come from growth in domestic consumption going forward.

The country's leaders have realized this and have even recently ordered several industries to reduce and shut down capacity. China's leaders wrote in their current 5-year plan that the economy would have to turn away from investments towards consumption, so that this development is actually happening should not really come as a surprise. We are seeing this development also in the oil data from China. The key oil product that is titled towards personal consumption is gasoline, and gasoline demand is still performing very well. Total gasoline demand is about 20% of the Chinese oil consumption. Diesel is however still the main refined oil product in China at about 36-37% of the total oil consumption and diesel demand is flat-lining. Diesel is in China used in the trucking sector but also in stationary usage like power generation, industrial production and heating. Diesel is much more connected to the growth in investments than gasoline. To put it another way; it requires a lot of diesel to build a brand new Manhattan.

The Chinese are not going to build as many new "Manhattans" any more. The weaker growth in investments is hence one reason why diesel demand is stalling.

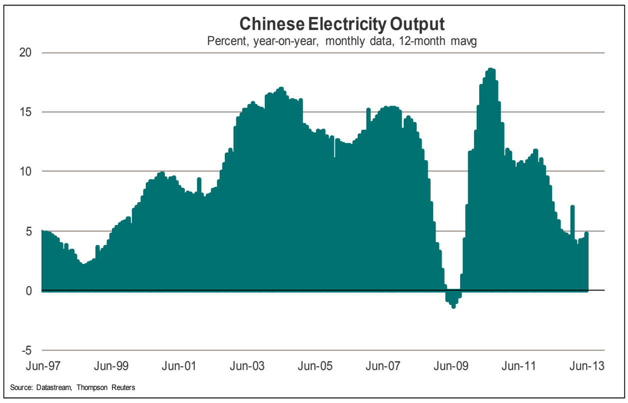


Another reason is probably that diesel is meeting competition from other energy sources in the stationary sector. Particularly wind energy is growing in an "insane" pace in China. According to a Reuters story installed wind capacity in China will increase another 30% during 2013 from 63 GW to 81 GW. If one assume a utilization factor for wind in China at 30% this translates into 211 TWh, which is the same size as one third of total German demand for electricity, just to put this into perspective.



There will also be strong 2013-growth in installed solar power capacity (up 10 GW) in hydro power capacity (up 21 GW) and in nuclear capacity. According to the story China currently have 30 nuclear power stations under construction with total capacity of 32 GW. Why are the Chinese investing so much in greener energy? We do not think the answer is their concern for CO2-emissions but rather local pollution in their large cities. Local pollution is much more dangerous for the Chinese government than "invisible" CO2-emissions because it can create social unrest, and if it is anything the Chinese government is afraid of it is the potential for social unrest. We saw tendencies in Beijing during this winter when local pollution forced people to stay indoors. The pollution reached levels twice as high as measured in any US city ever. And there were apparently ten other cities with higher pollution levels than Beijing. No wonder the Chinese government is concerned with a transition to a greener energy mix. Unfortunately (for us Norwegians) this translates into weaker growth in demand for oil.

We have read that several macro economists prefer to look at the growth in electricity output as a proxy for economic growth in China, rather than to trust the reported GDP-numbers. We think that makes a lot of sense. How can China reliably report their quarterly GDP-numbers just two weeks after the end of the quarter, when a tiny and well organized country like Norway use two months to report our quarterly figures? The Chinese GDP-growth for the first half of 2013 has been reported at 7.6% (7.7% in Q1 and 7.5% for Q2), so with that as the backdrop our 7-8% which we predicted last year does not look too bad. We do however suspect that the real growth in the Chinese economy could be weaker than the reported 7.6%. China's own Prime Minister Li Keqiang himself has stated that instead of using the reported GDP-numbers as a measurement of how the Chinese economy is doing he prefers to look at three specific indicators. Those indicators are; cargo volumes on the railways, electricity consumption and medium- and long-term loans. The growth in electricity output has only been 5.4% in the second quarter, so the reported 7.5% GDP-growth might be too high, even if it was reported lower than consensus expected.

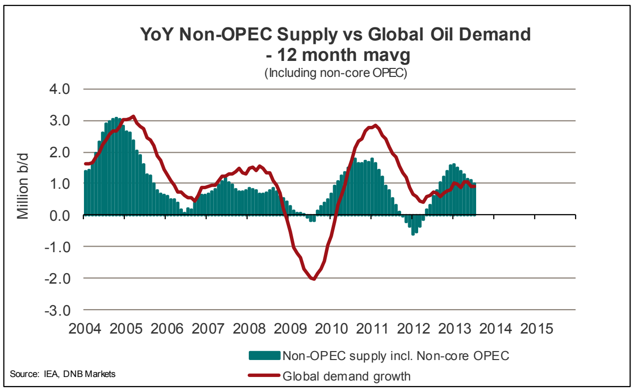


In our opinion it looks like the coming ten years are stuck with weaker Chinese economic growth than the prior ten years and in addition the growth will be less energy intensive as it will be less tilted towards investments and more towards personal consumption and service industries. No matter how we twist and tweak the Chinese oil demand numbers, the yearly growth in oil demand in percentage terms looks to weaken and not strengthen. And remember that this is happening in the country that has provided most of the oil demand growth the last 5-10 years.

5 Global oil supply

Many oil analysts prefer to split OPEC from non-OPEC when discussing global oil supplies. The premise is that OPEC acts as a swing producer and hence the changes in OPEC production do not reflect any structural changes but rather cyclical ones. So the supply need is often calculated as the “Call on OPEC”, which represents the market’s need for crude oil from OPEC. Instead of looking at OPEC as one unit we rather prefer to look at core-OPEC vs the rest of the world. The reason is that when we calculate the “Call on OPEC” we really want to know how much oil is needed from core-OPEC and not from OPEC. After all it is only the core-OPEC countries that are the real swing producers. History has proven that it is mainly Saudi Arabia, Kuwait and the UEA that will be cutting production when needed to balance the market. Hence we define these three countries as the core-OPEC producers. If we want to look at structural changes in production it makes no sense to for example keep Iraq, Angola, Nigeria, Iran and Venezuela in the OPEC category. Let us rather place them among the non-OPEC producers as these countries will basically always produce as much as they can.

By putting all the non-core-OPEC countries into the non-OPEC category it becomes visible that currently the growth in global supply from non-swing producers is currently larger than the growth in global oil demand.



What does this suggest? It suggest that either will Saudi have to accept global stock builds or the country will have to cut production to balance the market. Saudi Arabia throttled back output somewhat last autumn, but the flip side of that was higher spare capacity. For about a year now the growth in non-OPEC supply (including non-core-OPEC members) has surpassed the growth in global oil demand. In prior periods when this has taken place the oil price has fallen. The last year has not been different as Brent prices have been 5% lower in 1H2013 compared with 1H-2012. Note that the lost Iranian production due to the European oil embargo and the financial sanctions are included in the non-OPEC numbers. Hence the oversupply would of course have been much larger if those barrels had not been removed from the market.

The key production growth outside of OPEC has of course been coming from the US and Canada and is unleashed by the shale oil revolution in North America. US and Canada are however not the only countries in the world with growing oil production, even though they are the key contributors to growth. Meaningful production growth is also coming from countries like Russia, China, Kazakhstan, Colombia, Oman, Ghana, Iraq and Angola. If Sudan and South-Sudan can agree on their border issues we expect the third largest production growth outside of OPEC to come from South-Sudan next year as about 350 kbd of production has been shut in for more than a year now.

An important question for global oil supplies is if OPEC’s export capacity for crude oil is increasing or decreasing. This is not a very easy task to assess since no one really knows what OPEC’s real production capacity is. IEA has its monthly calculations on OPEC production capacity but many analysts doubt their numbers. One way to calculate the OPEC production capacity would be to find a not too distant point in time when the cartel probably maximised their output, then deduct field decline and add new projects that has been coming on stream since that point. An excellent starting point would be the summer of 2008, when oil prices were approaching 150 $/b. Saudi Arabia, Kuwait and UEA were most likely not happy with the price explosion we saw in 2008 and probably interpreted that 150 $/b could destroy the longer term prospects for oil's market share in the energy mix. Hence we believe core-OPEC probably produced as much as they could in June 2008. The rest of the cartel members normally just produce as much as they can anyway, and particularly when prices are rising.

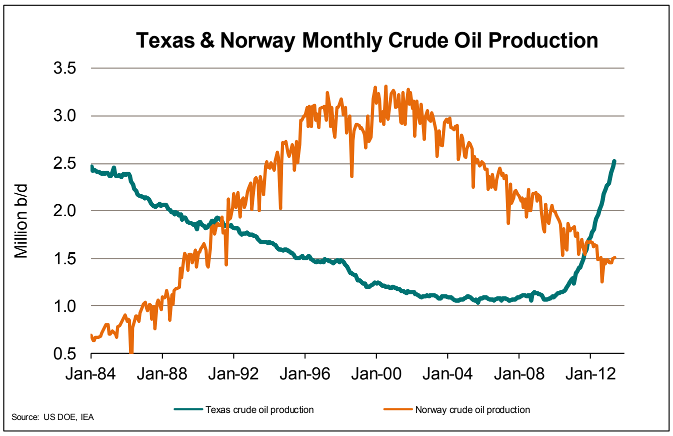
In June 2008 OPEC produced 32.4 million b/d of crude oil according to the IEA database. If we deduct field decline, add large new crude projects and assume that trend line oil demand growth in OPEC countries will continue we estimate that OPEC's export capacity for crude oil will not be much changed by 2015. Our calculations are shown in the slide package that will be sent out together with this report.

6 The North American shale oil revolution

The most interesting thing happening to global oil production is however not happening inside OPEC, like everyone thought it would just a couple of years ago. The by far most important development in global oil supplies the last two years has been from the so called "shale revolution" going on in North America.

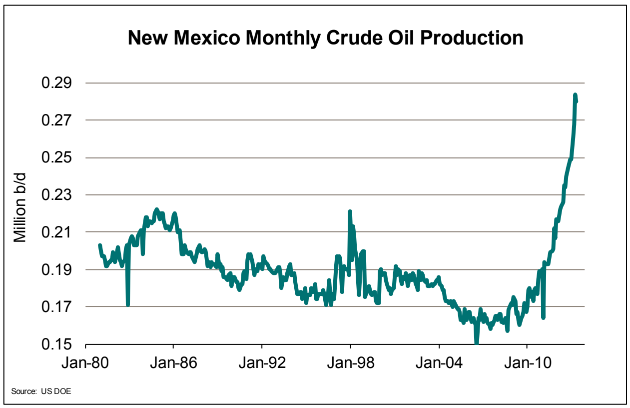
Shale oil is labelled as unconventional crude oil, but it is really just unconventional with respect to how it is trapped. It is for example not to be compared with synthetic crude in Venezuela or Canada, that has to be diluted or go through an upgrader before it can be sent to a traditional refinery. Most of the shale crude oil is light sweet in quality and as long as you have gotten it to the surface you can send it directly to the refinery. We suspect that 10-15 years down the road the shale oil will not be branded as unconventional any more.

Total US crude oil production is up more than 1.7 million b/d just the last two years. In our presentations we have however found that one of the best ways to illustrate the magnitude of this new shale oil industry is to compare crude oil production in Texas with crude oil production in Norway. Norway is still known by many in the world as a large oil exporting country. We are still a large producer and exporter, but Norwegian production peaked just above 3 million b/d around the change of the millennium and has since been cut in half. Texas crude oil production also peaked at about 3 million b/d, but that was more than 40 years ago. Since then, Texas production has been in a steady decline, but since 2004 it looked to stabilize just above 1 million b/d. As global oil prices started to increase, the field decline in Texas was kept in check through larger investments in existing fields. The production shock has however happened only the last two years in Texas. In 2010 crude production started creeping upwards, but in 2011 and in 2012 the process has accelerated. Two years ago Texas produced 1.4 million b/d, now the crude production has increased to above 2.5 million b/d. This enormous increase of 1.1 million b/d in just two years, from a state that was just supposed to fight decline rates, has probably been the largest upside surprise of oil output in the history of oil.



Less than two years ago Norway and Texas were at the same level of crude production but now Texas is producing about 1 million b/d more than Norway. This is the best example of the US shale oil revolution in our opinion and it illustrates that the oil price in itself is immensely important for how much production that will come to the market. Had the oil price stayed below 50 $/b these new shale oil resources would not have been developed. The increase in Texas production the last two years alone has been larger than crude production in the OPEC members Algeria, Ecuador and Qatar. Had the state of Texas been an OPEC member it would have been among the cartel's largest producers.

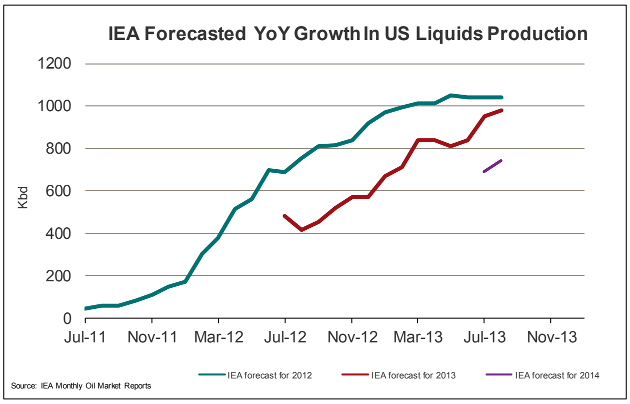
One year ago the production in Texas had reached 1.9 million b/d and we asked ourselves; is it really plausible that production will just stop at that level because of high decline rates and lack of sweet spots? Our conclusion was that it was not plausible. We do not think it will be possible to continue the Texas production growth in the same break neck pace as we have seen the last two years (the graph showing production is almost bending backwards…), but we are convinced that shale oil production in Texas will be much higher in 2020 than were it is right now. So far most of the growth in shale oil production has been coming from Texas and North Dakota, but more recently we have also seen very meaningful production growth in both Oklahoma and in New Mexico.



6.1 Few saw this coming

The oil market did not see this revolution in US oil production coming. Despite the large growth in shale gas production, most people thought the larger molecules in oil would not be possible to release using the same techniques as for shale gas.

In July the IEA released its first initial take on each country's oil production for 2014 and the agency now estimate that US oil liquids production growth will be about 0.7 million b/d for next year. When IEA last year made its first assessment of 2013 US oil production growth it was put at almost 0.5 million b/d growth. The growth so far this year is at almost 1 million b/d. Currently the IEA forecast 2013 growth of 980 kbd, so there has been a massive upward adjustment by the agency since July last year. The history for the last two years has been that IEA has been forced to adjust its production growth estimates for the US upwards in practically every monthly report issued since July 2011. When the agency forecasted US oil production growth for 2012 during the summer of 2011, the estimate was that production would grow by 45 kbd. The result became more than 1 million b/d.



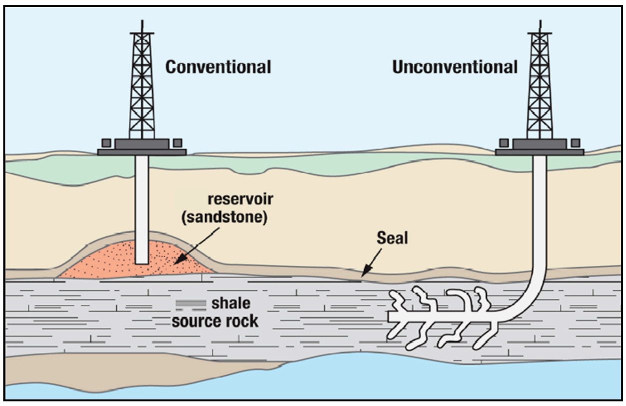
This must be the largest upside surprise ever for any country. The agency's first initial assessment for 2014 US oil production growth is however quite much higher than the first initial takes for 2012 and 2013 so we do not expect the same massive upward revisions to the 2014 forecast as we have seen for 2012 and 2013

In IEA's World Energy Outlook from 2008 the IEA used most of the pages under unconventional oil to discuss Canadian oil sands and other heavy oil. Biofuels were discussed and there was some brief discussion of oil shales. Shale oil is not to be confused with oil shales, or what is also sometimes labelled Kerogen. Kerogen (or oil shales if you want) constitutes the building blocks of conventional oil, but are less matured and closer to the surface than shale oil. There are large oil shale (Kerogen) resources in the US, but it requires heating and processing to make these resources possible to refine by a conventional refinery. The extraction of oil shale (Kerogen) resembles that of open pit production of Canadian oil sands. This is an industry that is similar to mining. Canadian bitumen (oil sands) needs to be run through an upgrader before it can be sold to a conventional refinery and making oil shales (Kerogen) useful for a refiner is said to be more expensive than the Canadian oil sand industry. Oil shale received more attention that shale oil plays until a few years ago due to it being closer to the surface and hence with the technology that prevailed at the time it was possible to access, while shale oil was until recently seen as impossible to extract economically. The IEA wrote a couple of sentences about deeper resources in its WEO 2008. The agency wrote; "*Deeper resources require the use of techniques to enhance the productivity of the formation (such as hydraulic fracturing).* ***The main US resource is the Green River Formation (Wyoming, Colorado and Utah)*** *with four basins. Early experiments in the 1980's were halted due to the unfavorable economics and poor operational performance.*" It is interesting to note that the IEA did not write a word about the Eagle Ford field or the Permian Basin in Texas and not a word about the Bakken in North Dakota.

6.2 How long will shale oil be labelled as unconventional?

Shale oil reservoirs lie deeper than oil shale (Kerogen) and have had more time to mature to high quality crude oil. The layers of shale oil can stretch horizontally for hundreds of miles and mainly consist of clay stone. The expression “Tight Oil” is not exactly the same as shale oil, because unlike shale oil the tight oil formations consist of siltstone or mudstone, without a lot of clay in the reservoir. “Tight Oil” is however extracted with the same techniques (horizontal wells and hydraulic fracturing) as shale oil. Most analysts include “Tight Oil” when referring to shale oil plays in the US, so it seems it will not make too much sense to separate tight oil plays from shale oil plays when discussing technology in use and production figures.

The shale oil resources can be seen as the source to the conventional reservoir. The crude oil is formed under years and years of pressure in the source (the shale oil) and then by time migrates up to a “geological trap” which in the oil industry is the reservoir that the geologists have been trying to find. The first trillion barrels of oil that the oil industry has extracted since the modern oil age started in 1859 has mainly come from those conventional geological traps. Below every reservoir there is a source where the oil has migrated from. Geologists sometimes call the source “the hydrocarbon kitchen”. The geologists have known about these “kitchens” for decades but the cost to extract this oil has been way too expensive because the technology had not developed adequately to allow economic production. Now this has changed through the combination of hydraulic fracturing and horizontal wells.



Source: PIRA Energy

Neither horizontal wells nor hydraulic fracturing are new techniques at all by themselves, but high oil prices can really make things happen with respect to creativity as we have seen several times before in history. We have seen videos with Texan oil men stating “what’s the big deal with fracking? I did my first frack-job in 1970”. In fact the fracturing technique is even much older than 1970. The technique was first used in the US in the 1940s. By 2002 a million fracturing jobs had been executed and currently about 95% of all wells drilled in the US is using hydraulic fracturing according to the National Petroleum Council. Commercial horizontal wells are a newer technology but have already been used quite extensively in the oil industry since the 1980s.

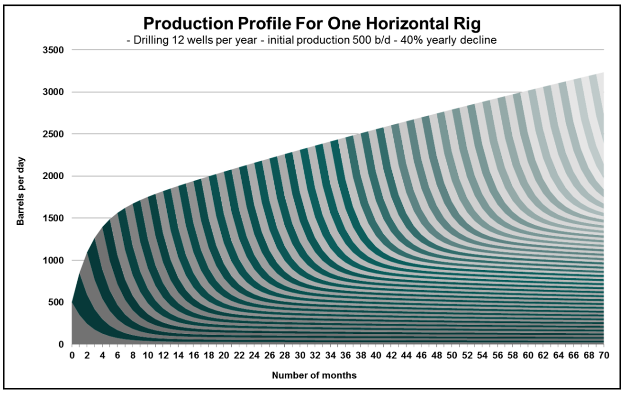
The new thing was the combination of the above mentioned technologies, which in the starting phase was only attributed to the development of natural gas resources. First the operator drills thousands of feet vertically and then turns the well horizontally into the shale layer. Then the fracturing job starts. Large horsepower trucks pump chemicals, water and sand into the well with very high pressure. This cracks up the shale formations and allows gas and oil to flow up the well. These fracturing operations occur in multiple stages along the horizontal arm of the wellbore.

The first large-scale fracturing job with horizontal drilling was executed in Texas in year 2000 in the Barnett Shale formation. Still it took several more years until the market realized that a game changer had taken place and US natural gas prices started to plummet. Until 2007 almost everyone believed that US natural gas prices could only go one way and that was upwards. At the time US natural gas was trading at about 8 $/MMBTU. Gigantic irreversible investments were made to build import terminals for LNG into the US. The enormous Shtokman project in the Barents Sea was thought to contribute by exporting LNG to the US. Now everything is turned around, and people are instead applying to export LNG out of the US. Two LNG export terminals are already approved, and more than a dozen other applications have been filed.

The last ten years the oil industry has moved towards smaller and deeper fields, resources further from the market, more complex projects, more resource nationalization, higher government take, etc, etc. The marginal barrels have to a large extent become ultra-deep-water barrels. Then suddenly the marginal barrel is about to change from an offshore industry that has a lead time of 7-10 years until the cash flow turns positive to a land based industry that instead resembles a manufacturing process. The development of a large offshore field will demand investments over several years and when the project is started these investments will normally not end if the oil price temporarily falls. The shale oil industry is a completely different animal with a lead time of only 1-2 years, where investments will quickly suffer if the oil price drops below break-even, but again will restart quickly if the oil price again rises to economically viable levels.

6.3 High decline rates but shale oil will still continue to grow

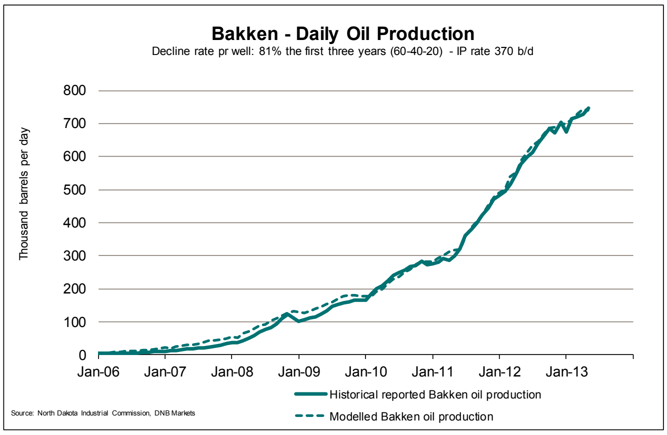
The key argument against further production growth in the US shale oil industry is the very steep decline rates that are prevailing in this industry which makes the treadmill effect more and more challenging. One has to "run quicker and quicker" just to stand still. The typical shale oil well declines about 80% in production within its first three years of production. There after production looks to stabilize and only drop slowly. The typical decline curve is hence about 60% the first year, 40% the second year and 20% the third year. It is however not correct to compare these wells with more conventional oil wells that have a much lower decline rate than the mentioned figures. Why is that? First of all it takes on average less than 30 days to drill a shale oil well. This means that, on average, every rig can drill about twelve wells per year.



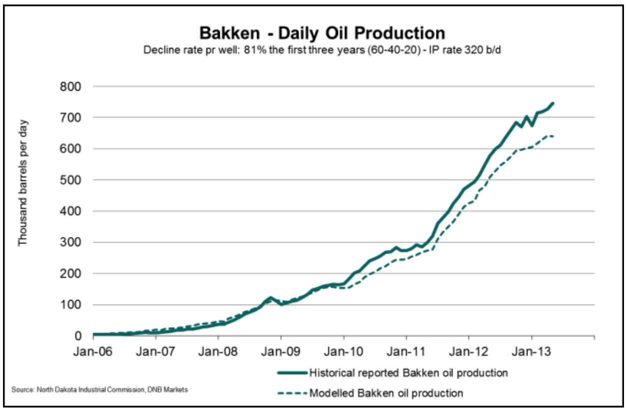
Source: DNB Markets

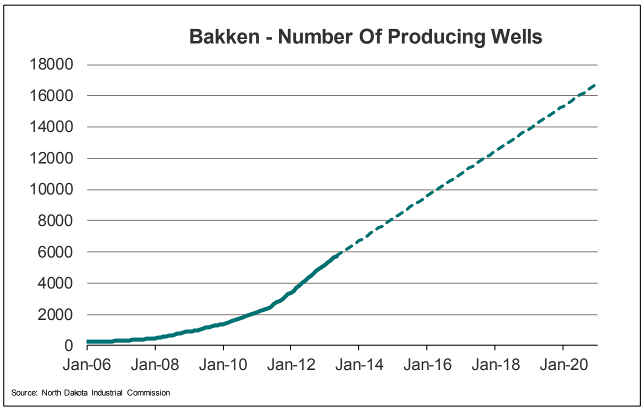
This is highly different from the offshore industry where it can take about 100 days to drill a deep-water well. Secondly the cost is only a fraction of drilling a deep-water well. From what we understand it now costs about 7-9 million USD to drill a horizontal shale well, while a deep-water well can cost 100 million USD. The shale oil industry is more comparable to linear industrial production. The more wells you are able to drill, the more production you will get. Geological costs are small compared with the offshore oil industry. Yes you need to drill a lot of wells to increase production, but the good thing is that it is much easier and much cheaper to drill those wells than in the offshore industry. For an oil producer it is also much more flexible for the cost base since the lead time from investment to first production is so much shorter. One could argue that this industry almost have no CAPEX, only OPEX. This means that if oil prices were to drop below economic return, you can just stop drilling and hence cut your cost base. In the offshore industry, you have to be prepared to build up investments for maybe 6-10 years before you start getting payback and if the oil price has decreased when you start producing you do not cut back on any costs because the CAPEX that has already incurred are sunk costs anyway. You will continue to produce until the oil price drops below your operating costs. Hence the offshore oil industry and the shale oil industry are two very different animals. If you model the contribution of production from one typical horizontal oil rig in the shale industry you will see that as long as the rig can continue to drill-move, drill-move there is no production decline to be seen from the rig perspective even though every well has large initial decline.

Production is really only a function of how many wells are drilled multiplied with the production per well. We have made a model on shale oil production in the Bakken field in North Dakota where the input factors are the number of drilled wells, the initial production rate (IP-rate) and the decline rate per well. When using a 60-40-20 field decline rate on initial production (IP) of 370 b/d and the reported number of drilled wells the model is almost spot-on the reported production numbers.

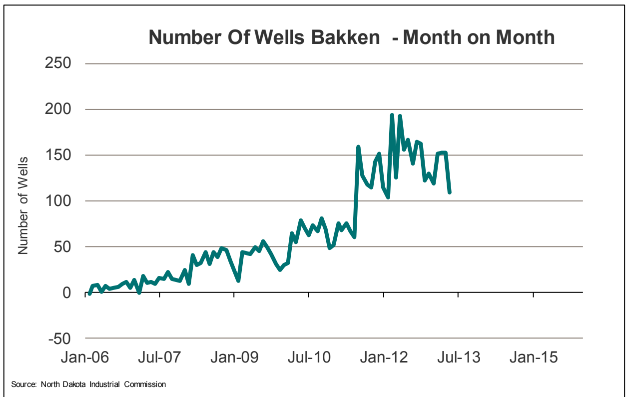


In fact the model fit is better in the years 2006-2010 if we use a lower IP-rate of 320 b/d. This suggest that there is a very significant learning curve going on, because if we use 320 b/d as initial production after 2010 the model returns way too low production numbers compared with the actual reported numbers.





It is logical that the sweetest spots are drilled first, but if this is the case in the Bakken, then the improved IP-rates (alternatively lower decline rates) must mean that the learning curve and efficiency improvements are more than offsetting the effect of less sweet spots to drill. The average number of new wells in the Bakken was 150 new wells per month last year. If that number of new wells drops to an average of 120 new wells per month going forward we will see the number of drilled wells in the Bakken increase from close to 6.000 wells now to above 16.000 wells by 2020.



Production will then increase to 1.4 million b/d if the IP-rate can be maintained at 370 b/d (as noted this IP-rate looks to be improving). This can happen even with the large decline rates described above. According to the international oil consultancy PIRA Energy; at two wells per square mile the saturation of the core areas of the Middle Bakken only is not reached until about 20.000 wells are drilled.

In other words, the resource base should not be a limiting factor for growth in a 2020-perspective for the Bakken field.

A factor that could dramatically increase the recovery rate in the Bakken is an increase in the well density from two to four wells per square mile. This could materialize as the industry is about to move from an exploration-production phase to a production-development phase. In the development phase the industry is likely to focus a lot of attention on well spacing.

6.4 Recent selected news flow from the US shale industry

<u>North-Dakota Bakken:</u>

- Whiting Petroleum is using an improved completion design on wells in its Missouri Breaks acreage in the Bakken play along the Montana-North-Dakota border. More frac sand, more hydraulic fracturing stages and cemented liners resulted in initial production of over 1.100 b/d at a recent well – more than double the rate of previous wells.

<u>Padd 5 – The Rockies:</u>

- Peak Exploration and Production reported 24-hour initial production of 2.600 b/d of oil (plus wet gas) from a well in the Turner sandstone formation in Wyoming's Powder River Basin. The horizontal well was completed with 14 hydraulic fracture stages.
- Noble Energy increased its production in Denver-Julesburg Basin of Colorado by 22% year-on-year to 90 kbd oil equivalent (62% liquids). Noble is operating 11 rigs in the basin, using extended reach lateral wells that have increased estimated ultimate recoveries to 750-1.000 b/d oil equivalents per well.
- Whiting Petroleum has improved production results in its Niobrara shale acreage in the

Denver-Julesburg Basin, using longer lateral wells and more sand to complete horizontal, hydraulic fractured wells, with recent initial production of a Niobrara well exceeding 1.000 b/d.

- Anadarko Petroleum continues to explore its acreage in Wyoming's Powder River Basin, with recent tests at 10 well sites averaging 500-600 b/d initial production, at costs of 7-9 million USD per well.

Midland – Permian basin:

- Anadarko Petroleum recently completed its first two wells in the Wolfcamp play of West Texas, with 24-hour initial production rates of 1.000 and 1.600 b/d.
- Energen Resources reported good results in the Midland subbasin's upper Wolfcamp bench recording initial production of 861 b/d (60% oil, 23% NGL), and believes all three Wolfcamp benches can be developed using horizontal drilling.
- Sunoco Logistics' Permian Express Pipeline started up in July at 90 kbd. This new line, shipping West Texas crude from Wichita Falls to Port Arthur, is expected to ramp up to 150 kbd by year-end, with a second phase of 200 kbd being considered for late 2014.
- Magellan Midstream Partners' Longhorn pipeline is expected to average 120 kbd in the third quarter, reaching full capacity of 225 kbd by the end of September.

Cushing Area:

- Newfield Exploration production in the Cana/Woodford play of Oklahoma is projected to reach 27 kbd oil equivalent by year-end, up from 16.4 kbd in the second quarter. Return on Cana/Woodford wells is currently exceeding 50%.
- Shell's Houma-to-Houston (Ho-Ho) pipeline will be closed between Houma and Nederland in August, in preparation for the full reversal of the pipeline by year-end. The section between Houston and Nederland was reversed at the beginning of this year.

Eagle Ford:

- Production from the Eagle Ford shale of South Texas rose 27 kbd to an estimated 881 kbd in May, up 366 kbd from May 2012.
- Eagle Ford pad drilling has increased to over 60% of all wells, from less than 40% last year, according to Halliburton. This is allowing more wells to be drilled using fewer rigs.
- EOG Resources broke the record for 24-hour production in the Eagle Ford with a well in Gonzales County producing 8.659 barrels of oil equivalent (7.513 barrels of oil).
- SM Energy is using increased efficiency and pad drilling to increase its 2013 Eagle Ford program from 75 wells to 95 wells. They report a 13% drop in well costs this year, to about $5.4 million per well.

Other shale news:

- Drilling contractor Nabors Industries expects US rig counts to decline in the second half of this year, due partly to high first half expenditures and partly to more efficient drilling. They estimate that wells drilled per rig have increased 20-30% since last year, now ranging from 1.1 wells per rig monthly for Bakken rigs to 1.5

6.5 The resource base looks to be higher than many thought

The continued growth in production can of course only take place if the resource base is large enough. You cannot continue to drill-move, drill-move if you are running out of resources. Consequently the size of the resource base is of very high importance when estimating the production numbers. Since this is such an important issue we bought into a study last year where a large part of the report was to estimate the US shale oil resource base. The report we bought from PIRA Energy was published in September last year and estimated that total recoverable US shale oil reserves were 113 billion barrels. According to the study; that should be large enough to see US shale crude oil production grow to a peak of 5.9 million b/d by 2013. PIRA used a recovery factor of 7.5% on the oil in place to reach this estimate. Since then PIRA has however increased its estimate of recoverable shale oil resources in the US to about 170 billion barrels because they believe the recovery factor will in fact be larger than 7.5%. One of the key issues that will improve the recovery factor is tighter and more optimal well spacing as already mentioned above. PIRA now believe US shale oil production will peak at about 7 million b/d instead of 5.9 million b/d like they forecasted a year ago. To put the 170 billion barrels in perspective, the largest oil finding in the world in 2011 was the Johan Sverdrup field in Norway. The recoverable reserves in that field are expected to be about 3 billion barrels.

As already mentioned in the start of the report, the US Energy Information Administration (EIA) in June for the first time issued a global assessment of the world's shale oil resources. The EIA in that assessment doubled its estimate of recoverable US shale oil resources to 58 billion barrels.

Rank	Country	Shale oil (billion barrels)	
1	Russia	75	
2	U.S.[1]	58	(48)
3	China	32	
4	Argentina	27	
5	Libya	26	
6	Australia	18	
7	Venezuela	13	
8	Mexico	13	
9	Pakistan	9	
10	Canada	9	
	World Total	345	(335)

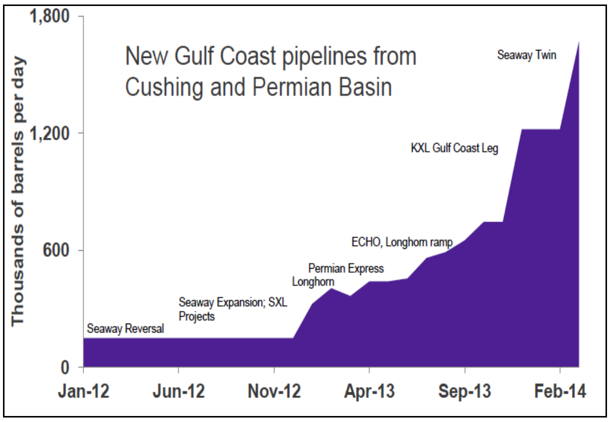
[1] EIA estimates used for ranking order. ARI estimates in parentheses.

Source: EIA

That is still way lower than the PIRA assessment of 170 billion barrels, but according to PIRA the EIA is still playing catch up.

6.6 Improving infrastructure impacting price differentials

What is the consequence of the large growth in US oil production for the world oil market? Since 2011 the large growth in production has mainly affected the domestic landlocked US crude price negatively (WTI). There has been a limited opportunity to transport all the crude produced in West Texas and in North Dakota to the US refinery cluster which is mainly found on the Gulf Coast. The new crude has mainly been moved by trucks, barges and rail, which are expensive transport solutions. During 2013 we have however seen and will continue to see large increases in much cheaper transport opportunities as pipeline expansions are brought on stream.



Source: Thompson Reuters

This is increasing the bids on landlocked WTI crude oil from the coastal refiners, but the flip side is less demand for international imported crude oils. According to the weekly US oil statistics, the US is now importing 1 million b/d less crude oil than a year ago. Through the imports channel the US shale crude story has thus gotten international relevance for the crude market. This is one of the key reasons why the Brent price has averaged 5.7 $/b lower in the first seven months of 2013 than the same period last year. The 1 million b/d that the US has lost appetite for since last year is now available to other countries. US crude oil imports have trended lower since 2009, but the drop has really picked up pace the latest year and crude imports are now hovering around 8 million b/d. At the peak levels in 2004-2009 it was often above 10 million b/d. What has happened so far is in our opinion only the beginning though. We believe US crude oil imports will be cut in half by the end of the current decade, mainly due to the increased domestic crude production but also because of weaker trending domestic oil demand. If this materializes it implies cheaper available crude oil for other parts of the world. By 2020 we believe West African crude oil grades will have to move mainly to Asia but also to Europe, and we believe most of the Middle Eastern crudes will have to move towards Asia instead of the US. Some strategic barrels could of course continue to move to the US (Saudi sending crude to its joint venture Motiva Port Arthur refinery for example), but the broad trend will be that Middle Eastern barrels will have to find other homes than the US by 2020 in our opinion.

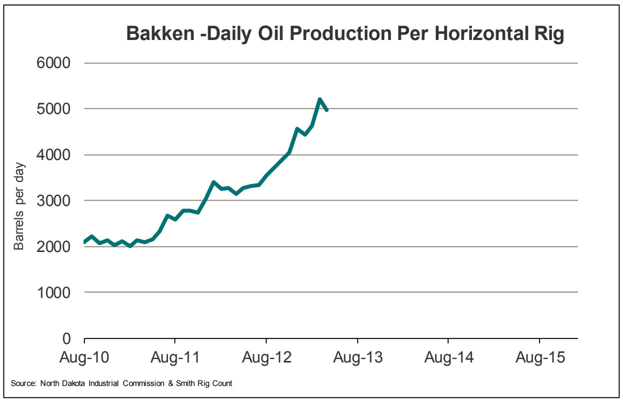
7 Cheaper oil but not cheap

So with all this extra supply coming into the oil market, why are we not more bearish than we are to oil prices? Why do we only predict Brent prices to drop to 90 $/b (nominal terms) as an average price during the current decade? After all, 90 $/b is a historically very high oil price. Cannot the oil price decrease back to 50 $/b?

7.1 High break-even prices for shale oil

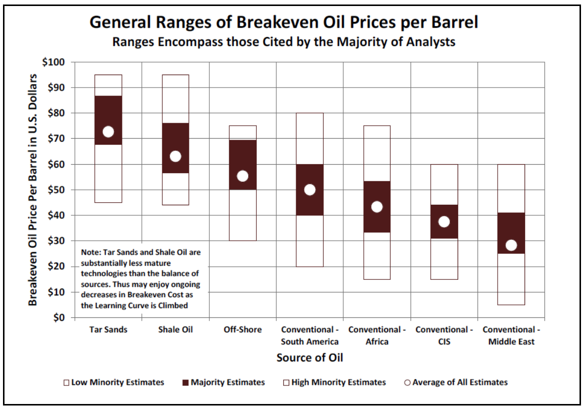
The disadvantage with the shale oil barrels are that they are quite high up on the cost scale compared with most other sources of oil supplies. According to a calculation by PIRA Energy the Brent price required for economic development for most of the shale oil we expect to see by 2020 is in the 70-80 $/b range. The Eagle Ford “oil window” is seen at 70 $/b and Bakken at 76 $/b.

It is an open question if these costs will go up or down by the end of the decade. We see good arguments for both directions. On the one hand, this industry is still very early in the learning curve and that has the potential to bring costs down. Examples of efficiency improvements are constant expansions of the number of wells drilled per Padd. In North Dakota we have read that applications have been issued to drill 24 wells per Padd at the most, while the preferred number right now seems to be 7 wells per Padd. We see operators experimenting with hydraulic walking of the rigs to avoid the cost of rigging up and down and the largest rig operators report that the horizontal rigs they are delivering to the market these days can drill 24 wells per year instead of 12 which is the average for the rig fleet. With such a revolution going on in the rig fleet, it does not work to count the rigs anymore to get a feel for where production and the number of wells are going. The weakest and poor performing rigs are scrapped and new more efficient rigs are coming in. Hence the horizontal rig count in the Bakken has fallen from about 180 rigs to about 150 rigs since May last year, but still production is up 167 kbd in the same period. This implies that the performance per rig is accelerating.



An area where it could be a large potential to save costs in this industry is in the fracking-process itself, which is estimated to constitute more than half of the extraction costs. According to Bernstein Research, 80% of the production comes from only 20% of the frack-zones. This implies that if the industry can either avoid fracking the zones that are not contributing to production or if somehow the fracking-technique can be improved so the underperforming frack-zones can contribute to production, the unit costs can come significantly down. Arguments counting for higher production costs in the future are however that the industry will exploit the sweet spots first and that it will be more difficult to extract barrels from areas with a poorer geology. Also we should expect much tougher regulations on this industry going forward due to environmental concerns, and that could add significantly to the cost of extracting these barrels. At the margin we have more faith in lower than higher costs in this industry looking 5-7 years down the road, due to the learning curve, but we realize that costs could also move higher from an already elevated level.

No matter what the cost of extracting these shale barrels will be 5 years ahead, we still believe that a higher oil price will be required to extract the next trillion barrels the oil industry is going to produce, compared with the first 1.1 trillion barrels that are extracted so far in the modern oil history. Shale oil extraction will most likely still be quite high up on the cost curve compared with other oil resources also in the coming years in our assessment. The US consultancy J.T. Gabrielsen Consulting has gone through loads of different publications to map up the industry assessment of the break even costs for the different sources of oil supply. The industry operates with quite large ranges of costs for the different sources. It is often hard to compare assessments because some assessments do not include finding and development costs, taxes, etc. while others do. And the cost of capital used in the calculations can be different as well. Sometimes it is like comparing “apples to bananas” and for each project, only the project owner has the "real" calculation which is of course kept a secret to everyone outside the particular organization. The ranges are however probably still providing a broadly correct picture of the different costs per source and we would rather be approximately right than precisely wrong.



Source: J.T. Gabrielsen Consulting

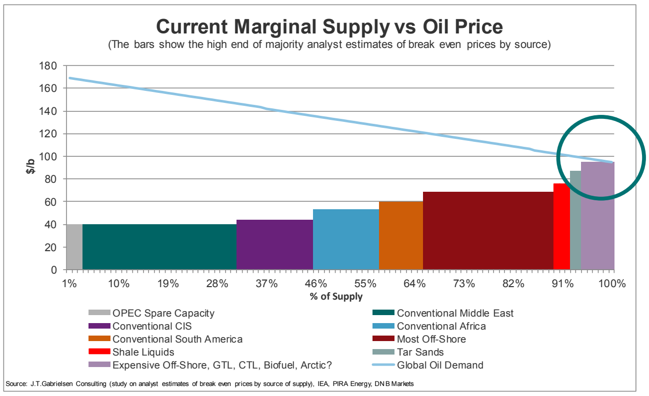
The lowest cost barrels are, not surprisingly, coming from conventional Middle East production. The majority of the estimates have the cost of those barrels in a range from 25-40 $/b, but the average is just below 30 $/b. Offshore barrels are in the 50-70 $/b range while shale oil is second highest on the scale in a range from 57-77 $/b for majority estimates. Tar sand is more expensive than shale oil, and we would add Gas-to-Liquids (GTL), Coal-to Liquids (CTL), Biofuel and Arctic barrels to that category as well. Even though the range for offshore production is lower on the cost scale than shale oil, the ranges are overlapping. In other words, there are many large offshore projects that would require a higher oil price to be developed than the best shale oil projects. Therefore it cannot be claimed that since offshore is generally lower on the cost scale than shale oil, all offshore projects are safe. As an example, when we look closer at the Goldman Sachs "380 projects to change the world-report", we count 18 offshore projects that Goldman evaluate has a break even cost above 80 $/b. These projects are found in US GOM, Nigeria, Angola, Brazil, Russia, Congo and Ghana. In addition there is the Kashagan project that is the most expensive offshore project on the list, but that field is finally starting to come on stream during 2013 and the owners have so much sunk costs in that project that it will materialize no matter what happens to the oil price going forward.

7.2 Which projects will suffer?

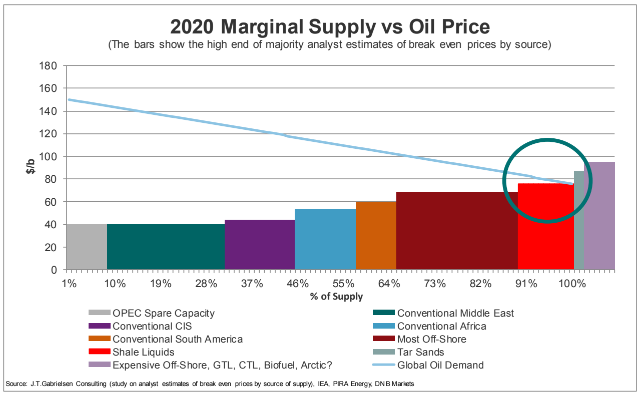
As a consequence of the North American shale oil revolution, there is a risk that going 5 years down the road; Norway will not find it economical to invest in the most expensive Arctic resources we believe we have hidden under the seabed as those projects may prove to be higher on the cost scale than most of the shale crude. We have already seen the large Johan Castberg project being put on the shelf for now, as the break-even costs were higher than many thought for that project. Increased taxation was what put the final "nail in the coffin" for that project. It could be put back on the agenda of course but for now it seems Statoil has many other projects on its list that have better economics, despite the large resource base for that particular project.

The growth in shale liquids production will, if global unplanned outages do not continue to increase, force the core-OPEC countries to cut production if they want to maintain oil prices close to 100 $/b. The flip side of those cuts would be higher spare capacity. That spare capacity would be among the cheapest barrels to produce and suddenly the world will not need the most expensive projects any more.

Now:



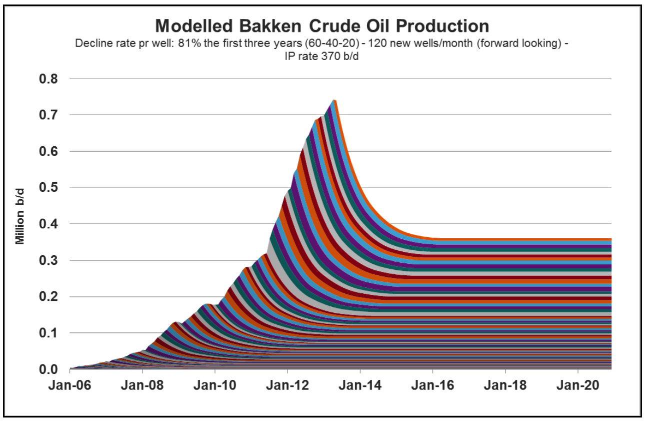
In 2020?



Based on this we would prefer not to be exposed to the most expensive oil projects if we can choose, because at the end of the day they may not materialize. We are not saying and have never said that the world will not need a lot of new offshore oil resources in the coming years, but we think investors should try to avoid the projects that are highest up on the cost curve.

7.3 Contribution from non-OPEC if prices fall too much

As we have already stated above, we do not believe the world is heading back to cheap oil of 50 $/b or lower on a sustainable basis. One of the very interesting aspects of the shale oil production is that for the first time, OPEC will see help from non-OPEC with respect to production cuts if the oil price falls too low. Should the Brent price for example drop to 50-60 $/b, most of the drilling in the Bakken field would stop, and what would happen to crude oil production in the Bakken field if no more wells are drilled? The answer is easy to see in our model. Within two years, production would be cut in half.

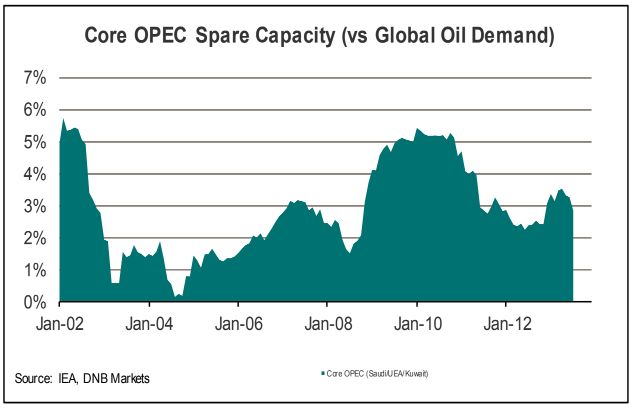


Source: DNB Markets

Such a quick and meaningful supply side response to lower prices is something we have not seen before from non-OPEC producers. It creates a safety valve for oil prices, and is a powerful argument for why it is difficult to imagine a sustainable return to cheap oil. An important premise for this argument is however the development in the costs of extraction for these resources and how global this industry has become during the coming ten years. If the cost of extraction is cut in half by 2020, the shale technology will spread much quicker to other parts of the world and our “safety valve argument” would no longer be valid. In our oil price forecast we have however only assumed marginally lower extraction costs for this industry within the current decade and also that no other regions of the world would produce meaningful volumes of shale oil until after 2020.

7.4 Geopolitical risks in the MENA are supportive for oil prices

In addition to the high extraction costs, solid support for medium-term oil prices are coming in from geopolitical risk in North Africa/Middle East (MENA). Core-OPEC spare capacity is still low at only about 3% of global oil demand and this makes the geopolitical risk more important than if spare capacity was much higher.

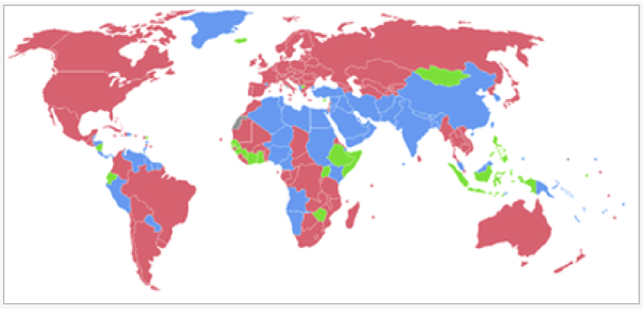


We continue to argue that geopolitical risk in MENA will be higher in the coming ten years than in the prior ten years due to the Arab spring that really escalated in 2011.

In many ways the MENA region is perfectly set up for social unrest. There are domestic issues like aging autocrats, minority rule, large unemployment and a very young population. There are also many regional conflicts like the Sunni-Shia, Iran-Saudi Arabia, Israel-Palestine and the Kurds autonomy in Iraq/Turkey. The civil war in Syria is in addition having spill over effects into other neighbouring countries. Iraq is a good example of this where we have seen exploding violence against civilians the last three months. Since 2009 the average number of civilian deaths in Iraq has been quite stable at around 300 per month. In both May and July however the number has been close to 1000 deaths per month. We have also seen more negative effects on oil production from Iraq lately as the northern export pipeline (Kirkuk-Ceyhan) has been blown up every other week, limiting Iraqi exports through the Mediterranean port of Ceyhan in Turkey. On top of this there is external pressure against Iran from the western powers in order to curtail the country’s nuclear program. The EU has imposed the oil embargo and financial sanctions and the US has imposed financial sanctions. In late July the US congress passed a new bill that would further tighten sanctions against Iran. The target seems to be to decrease Iranian oil exports to almost zero. The bill has however yet to pass the senate and a vote there is unlikely until at least September. Some political experts say the Obama administration would work to postpone the vote in the senate while diplomacy is pursued. Many people have hopes that the newly elected and more moderate Iranian president Rouhani can change the tone in the nuclear standoff between Iran and the western powers. Rouhani was inaugurated on August 3rd and both Iran and western powers have indicated a willingness to resume nuclear negotiations. Successful negotiations could bring a lot of barrels back to the market but unsuccessful negotiations could bring even more barrels out of the market. The whole Iranian nuclear issue is an open wild card for the oil market.

Late July official peace talks began in Washington between Israel and Palestine for the first time since 2010. US secretary of state John Kerry said all issues would be dealt with during nine months of negotiations and that he believed a permanent peace accord could be reached in that time frame. The two parts are however far apart on significant issues and we would evaluate the chances of a long-lasting peace deal as low. As long as there is progress in the talks however it could reduce some of the geopolitical fractions in the region.

Overall we still believe that the demographics of the MENA - which is basically populated with young, unemployed males that now have access to information flow through the internet/TV/smart phones - is a mix almost designed for social unrest.



Map indicating the human sex ratio by country.[1]

Countries with more **females** than males.

Countries with the **same** number of males and females (accounting that the ratio has 3 significant figures, i.e., 1.00 males to 1.00 females).

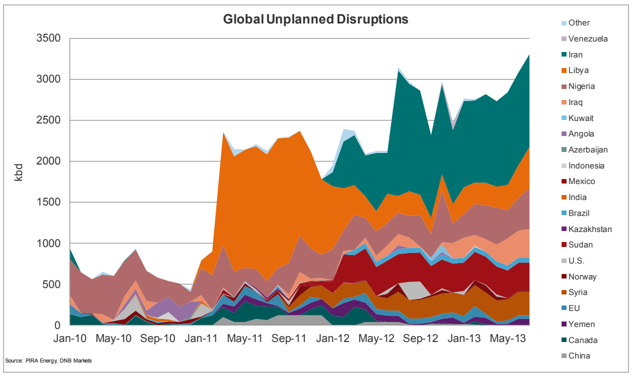
Countries with more **males** than females.

Source: UN population division

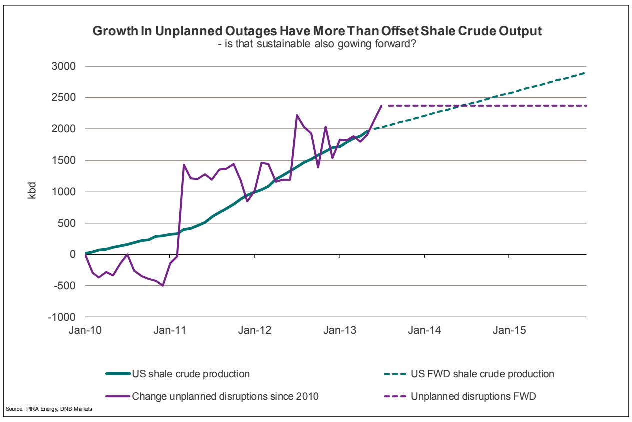
The Financial Times published an interesting picture in February 2011 to illustrate a documented phenomenon that could help explain some of the background for the Arab spring. It showed the so called J-curve. The J-curve shows that the stability decreases in a country that has started to increase its social and political openness from a formerly tight level. The MENA region is placed just at the bottom of this J-curve.

7.5 Can unplanned outages continue to increase?

Since 2010 outages in oil production caused by social unrest and geopolitics in the Middle East and Africa has "exploded" to the upside. Based on our data, the unplanned outages of oil production globally have increased from about 500 kbd in 2010 to now stand above 3 million b/d. The largest unplanned outages are currently in Iran, Libya, Nigeria, Iraq, South-Sudan and Syria.



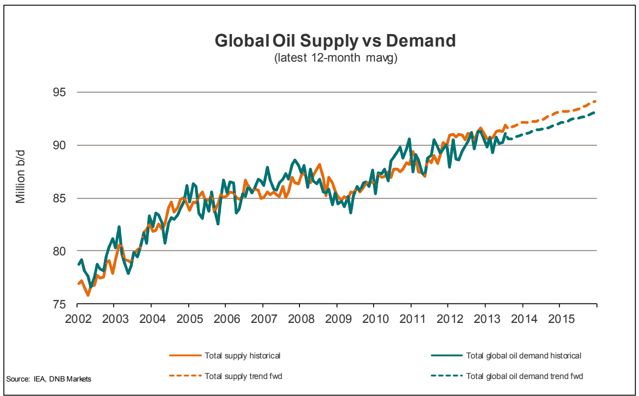
In our opinion this very large increase in unplanned shut in oil production comes a long way in explaining why oil prices are still trading above 100 $/b despite the North American shale oil revolution. Since 2010 the growth in unplanned outages has more than offset the growth in US shale oil production. The important question for the future of the oil market hence becomes; will this continue also in the coming 5 years?



History has shown that outages will continue to materialize in the MENA. It is almost impossible to know where, how much and how long future outages will last. They are unpredictable by nature, but we think the *level* of outages will continue to be high and hence support oil prices the rest of the current decade. We do not however believe that the *increase* in outages can continue at the same pace as we have seen since 2010. Our forecast is that the increase in shale oil production the coming 5 years will be higher than the increase in global unplanned outages. If that materialize, the global oil price will most likely be lower than today in coming years.

8 Which strategy will Saudi Arabia choose?

What kind of strategy will Saudi Arabia pursue if indeed the growth in shale oil output becomes higher than the growth in unplanned outages in the coming 5 years? Several analysts claim that Saudi Arabia soon will need oil prices of 100 $/b to balance their state budget because of rising social costs. And since the kingdom needs that price; that is the price we are going to get. Is it as easy as that? If the current trends in global oil supply and demand continue in coming years, core-OPEC will have to cut production if they want to balance the market and maintain 100-dollar oil.



But does that mean Saudi Arabia will choose to cut to protect prices this time? We are not sure. The fact is that Saudi Arabia does not really need a certain oil price to balance their budget, the kingdom needs revenues. The revenues from oil sales are a function of *both* price and volume. It is of course not a factor of price alone. Here is some food for thought when it comes to what kind of strategy Saudi Arabia will choose the coming years: Currently Saudi Arabia is producing about 9.8 million b/d which at 100 $/b is worth 358 billion USD per year. If as an example Saudi Arabia have to cut output by 1.5 million b/d to 8.3 million b/d to maintain 100 $/b, revenues will drop to 303 billion USD per year. How far can the oil price drop and still provide the same revenues of 303 billion USD per year? The answer is 85 $/b. Saudi Arabia could in other words earn the same oil revenues by maintaining production at 9.8 million b/d and let the oil price slip to 85 $/b as the kingdom would receive by cutting output to protect the oil price. This is just an example to illustrate the strategic choices that could soon face Saudi Arabia. The benefit for the kingdom of maintaining output at a higher level to a lower oil price is that it would provide a larger oil market share for them, and also probably higher global oil demand.

Volume cut: 2013-15	Million b/d	$/b price	Revenue mill $/d
Saudi crude production:	9.8	100	**980**
Saudi production cut:	**1.5**		
Saudi production after cut:	8.3	**100**	**830**

No volume cut: 2013-15	Million b/d	$/b price	Revenue mill $/d
Saudi crude production:	9.8	100	**980**
Saudi production cut:	**0.0**		
Saudi production after cut:	9.8	**85**	**830**

What the kingdom will choose to do is not "written in stone". During the 1980's the Saudis cut massively to protect the oil price but changed that tactic after losing too much market share and then targeted volume instead. This time it might be a better strategy to let prices slide towards 85 $/b instead. The Saudis are fully aware of the cost curves for the shale oil industry and they know that many sellers would disappear if the oil price drifted lower than 80 $/b. Why not let the market take care of this adjustment and just let oil prices slide 15-20%? As already described if the price falls more than that, then non-OPEC will come to the rescue instead and start cutting output (drilling less shale wells).

9 Net decline rates are lower than many think

We are approaching the end of this report but there is one final issue we would like to discuss. We still regularly meet customers and analysts who argue that global field decline has the effect that the oil industry will have to run faster and faster just to maintain current output, and that will not be possible without rising oil prices. If for example net field decline is 6.7% of the 90 million b/d global oil production, some claim the world would need to find and develop about 40 million b/d of oil resources before 2020. This will not be possible some claim and hence the oil price must rise much higher. There is no need to worry about these figures. We do not need to find and develop that many barrels before 2020. First of all the *net* decline rate is not 6.7%, even if the *natural* decline rate for *fields that have passed their plateau* production could be at that level. The other important issue to note is that the world's 380 largest oil projects (which we obviously do not need to find, and which of course are not in decline) will alone provide most of the increased extra production the world needs by 2020.

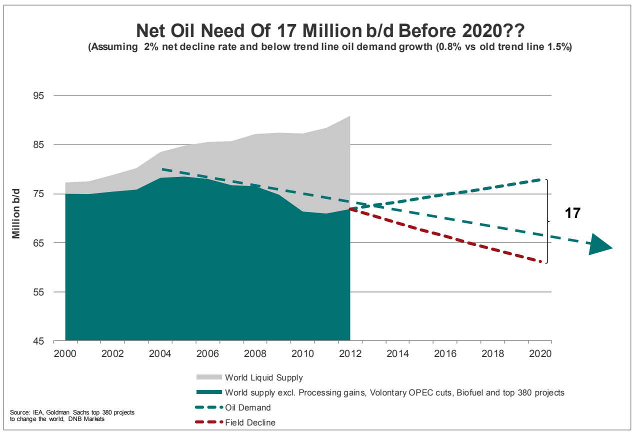
In its World Energy Outlook for 2008 the IEA conducted a large study on field by field decline rates based on a database mainly obtained from IHS-CERA but added also data from USGS, Deloitte & Touche and EIA. Based on its study the IEA concluded that the average decline rates world-wide is 6.7% for *post-peak fields*. The key word is as highlighted *post-peak fields.* IEA clearly states in their report that "for the purposes of our decline rates calculations, only fields that have reached post-plateau production are included" (page 235 in IEA WEO 2008). In the agency's definition post-plateau broadly means that output from the field has fallen to below 85% of the peak level. We all know that not all the world's currently producing oil fields are post their plateau. This of course means that one cannot apply the 6.7% decline rate on the 2013 oil liquids production base of 90 million b/d.

IEA's study was meant to give information on how much a *field that has reached its plateau* will decline in production every year, but our current oil liquids production base of about 90 million b/d does not consist of only fields that have reached peak-plateau. So what kind of decline rate should we use when deducting barrels from the current 90 million b/d? This is an extremely difficult task and nobody is going to get it correct as each different field's decline rate will depend on lots of different factors and geology is only one of them. Changes in technology, government take (tax) and investment levels are examples of factors that affect net decline rates as much as pure geology.

It is probably better to keep the decline rate exercise pretty simple and keep it a bit more top-down instead of risking huge errors because you miss out on the tax rate, technological break troughs or the level of investments. One way of trying to assess the net new oil need on a quite simple but we think powerful way is to start with total world liquids production, then deduct processing gains, biofuels and the largest projects in the world that we know are in ramp up (we use Goldman Sachs top 380 projects report to extract those projects which are in ramp up). One should also adjust for the voluntary production cuts from OPEC in 2002 and in 2009. If we do this exercise we should broadly speaking see the production in the world that are not in ramp up and we can calculate an approximate net field decline rate for that part of the production base.

Using this method it looks as if the adjusted production base has decreased from 75 million b/d in year 2000 to 72 million b/d in year 2012. That is not much of a decline and that is excluding all the large fields in the world that has been in ramp up. The average in the 2005-2010 periods, which is the period with the steepest decline, is 1.5%. To be aggressive, let us use 2% instead when calculating forward decline from 2013 to 2020. Adjusted production will then fall 11 million b/d to 61 million b/d in the mentioned time frame. The IEA WEO says 10 million b/d will be lost by 2020 (page 102 in WEO).

In the Goldman Sachs top 380 report, the bank estimate that the world's largest projects will increase their output by 25 million b/d from 2013 to 2020. Historically the assumptions for ramp up in these reports have slipped by about 30% from the initial estimates. Adjusting for normal slippage we still reach an increase of about 17.5 million b/d from these already known projects by 2020. We have already argued that we believe trend line global oil demand growth will decrease in the coming years. Instead of the1.5-1.7% that we have been used to for the past 25-30 years we rather believe in a new weaker trend line of about 0.8-1.0% per year. Such a trend line demand growth implies global oil demand would increase by about 6 million b/d by 2020. The net need for new global oil production by 2020 hence becomes 6+11 = 17 million b/d. The world largest already known project looks to be able to provide 17.5 million b/d, even with a 30% project slippage.

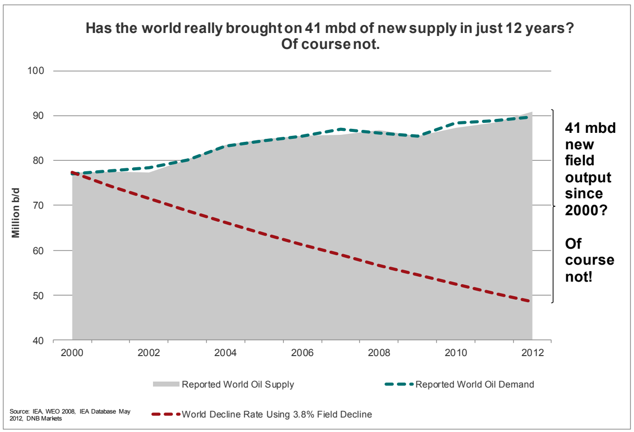


Another way of illustrating that field decline is not as large a challenge for net supplies that many seem to believe is to take a step backwards in time.

In IEA's World Energy Outlook from 2008 one could calculate from the provided numbers that IEA believed net decline from 2007-2015 would be 3.8% per year. Let us do an exercise using 3.8% net decline on world oil output in the year 2000 to see how much new oil the world would need by 2012.

In year 2000 the global oil supply was 77 million b/d according to IEA data. If we use an annual decline rate of 3.8% on that starting figure, we would have lost 28.5 million b/d of production by 2012. Demand for oil has risen by 12.5 million b/d in the same period. The net new

oil need since year 2000 based on the mentioned decline rate was hence 41 million b/d.
Since supply is matching demand, it implies that the world has been able to bring on 4 new Saudi Arabia in just the last 12 years. Can that really be possible? The answer is; of course not.

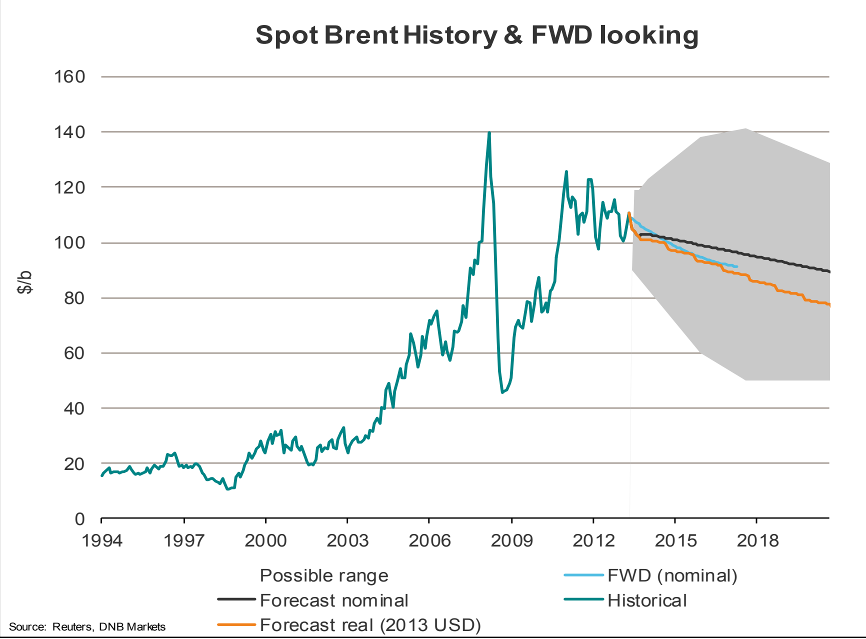


According to the mentioned Goldman Sachs "top 380-report" the largest projects in the world have contributed to about 15 million b/d of growth the last 12 years. In addition OPEC has increased its production by 3 million b/d. In total it looks as if we are nowhere near to have seen 41 million b/d new productions to the market during the last 12 years. So what is wrong with the calculation? The answer is that the net global decline rate must have been significantly lower than the 3.8% that we can extract from the IEA WEO 2008-report. Why has the net decline been much lower? The answer in our opinion is that the rising oil prices we have seen from year 2000 to 2012 has made operators invest significantly more in their existing production facilities and thus have kept decline rates in check. In other words, a high oil price translates to a lower global field decline rate than a low oil price. This should be supportive for oil prices going forward as well, because if oil prices should drop to 50 $/b we would expect global decline rates to increase and then lead to lower growth in oil supplies.

Based on all our above discussions, we believe a larger supply growth outside of OPEC than what we have seen the last ten years in combination with lower trend line oil demand growth will bring oil prices somewhat lower in the coming years. We do, however, not believe in a return to cheap oil due to the high cost of bringing the new barrels to the market, rising geopolitical risk and rising global field decline rates that will materialize if the oil price should fall too much.

10 DNB Oil Price Forecast

	Historical Nominal $/b	Historical Real (2011) $/b
2001	24.9	31.1
2002	25.1	31.3
2003	28.5	35.3
2004	38.1	46.6
2005	55.0	62.8
2006	66.2	72.7
2007	72.7	78.5
2008	98.7	101.6
2009	62.6	64.7
2010	80.4	82.0
2011	110.8	110.8
2012	111.7	111.7
	Forecast Nominal $/b	**Forecast Real (2012) $/b**
Q1-13	113	113
Q2-13	103	103
Q3-13	105	105
Q4-13	103	103
2013	106	106
2014	102	100
2015	100	96
2016	98	92
2017	96	89
2018	94	85
2019	92	81
2020	90	78



Source: Reuters, DNB Markets

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