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# Global oil supply

## Will mature field declines drive the next supply crunch?

Supply constraints seem a distant prospect in the current oil market, but a return to balance in 2017 will leave the World with severely limited spare capacity

Meanwhile, near term productivity gains are temporarily masking a steady increase in mature field decline rates which could cut existing capacity by >40mbd (>42%) by 2040e

We think risks of supply constraints will resurface long before risks of global demand peaking, and a steady tightening in the supply/demand balance post-2017 is behind our unchanged USD75/b long-term Brent price assumption



Play interview with  
Kim Fustier

**Disclaimer & Disclosures:** This report must be read with the disclosures and the analyst certifications in the Disclosure appendix, and with the Disclaimer, which forms part of it

# 10 things you need to know

1. The oil market may be oversupplied at present, but we see it returning to balance in 2017e
2. By that stage, effective spare capacity could shrink to just 1% of global supply/demand of 96mbd, leaving the market far more susceptible to disruptions than has been the case in recent years
3. Oil demand is still growing by ~1mbd every year, and no central scenarios that we recently assessed see oil demand peaking before 2040
4. 81% of world liquids production is already in decline (excluding future redevelopments)
5. In our view a sensible range for average decline rate on post-peak production is 5-7%, equivalent to around 3-4.5mbd of lost production every year
6. By 2040, this means the world could need to replace over 4 times the current crude oil output of Saudi Arabia (>40mbd), just to keep output flat
7. Small oilfields typically decline twice as fast as large fields, and the global supply mix relies increasingly on small fields: the typical new oilfield size has fallen from 500-1,000mb 40 years ago to only 75mb this decade
8. New discoveries are limited: last year the exploration success rate hit a record low of 5%, and the average discovery size was 24mbbls
9. US tight oil has been a growth area and we expect to see a strong recovery, but at 4.6mbd currently it represents only 5% of global supply
10. Step-change improvements in production and drilling efficiency in response to the downturn have masked underlying decline rates at many companies, but the degree to which they can continue to do so is becoming much more limited

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# Executive summary

- ▶ We look in depth at oil production decline rates and their implications for the long-term oil supply outlook; an issue receiving little attention in the current oversupplied market
- ▶ We see the oil market back in balance in 2017, with little spare capacity. Thereafter, accelerating decline rates are set to be a key factor in increasing market tightness
- ▶ Impending supply constraints are a key factor behind our USD75/b long-term (2018e and beyond) price assumption

## Why talk about supply declines now?

Given the backdrop of the past two years' severe oversupply in the global oil market, it's not surprising that few are discussing the possibility of a future supply squeeze. Indeed, most of the current debate on the long-term outlook for oil seems focused on risks to demand from progress on both the policy and technology fronts. While global oil demand growth rates are set to decline as this progress continues, we are still a significant way off the point that demand peaks in absolute terms – central scenarios from the main energy agencies such as the IEA, OPEC and the US EIA don't see this happening before 2040.

Meanwhile, we expect the past two years' severe crude price weakness to result in a return to balance in the global oil market in 2017. At that stage, we expect global effective spare capacity to fall to as little as 1% of demand. Supply disruptions have had only limited impact on price in 2015-16 due to the global oversupply, but the market will be much more susceptible to interruptions post-2017. In addition, given the almost unprecedented fall in industry investment since 2014, we expect the focus to return to the availability of adequate supply.

## Declines: the self-correcting mechanism for the oil market

What differentiates oil from other commodities is the natural production decline in all oil and gas fields after a period of plateau, which acts as a natural correcting mechanism in global oil supply. While global liquids supply has grown by more than 10mbd in the past ten years, this growth has been focused firmly on 1) OPEC crude (mainly Saudi Arabia and Iraq), 2) US tight oil (~5mbd), 3) natural gas liquids (NGLs, >3.5mbd) and biofuels (~1.5mbd). In fact, conventional non-OPEC crude supply of around 42.4mbd has shown no net growth over this period, as new field start-ups have been offset completely by declines in existing output.

## Decline rates set to increase, putting pressure on supply

We think several factors point to risks of accelerating declines in the coming years:

- ▶ Increase in declines over time due to a combination of a) deteriorating geology and b) the inevitable maturing of old fields, where declines have thus far been mitigated by technology.

- ▶ New fields becoming smaller: the world's production mix is structurally changing and relies increasingly on small fields rather than ageing giants. Small fields are likely to see faster declines as their limited size does not allow for long production plateaus.
- ▶ Discoveries point to this trend continuing: the average size of new oil discoveries has been falling for decades. Last year it reached a record low of 24mmbbls, a small fraction of the 1-2bnbbl average size of new fields starting up in the 1960's.
- ▶ We believe a range of decline rates of 5-7% (on post-peak production) is probably reasonable. This represents around 3-4.5mbd of potential lost production every year over the next few years – far more than unplanned production interruptions could take out in any given year.

#### Improving efficiency giving a false sense of security?

Improving plant and drilling efficiency have been important contributors to production holding up better than expected in many regions in 2015-16, and several oil majors have highlighted how this has mitigated their decline rates. However, we need to be cautious in assuming these lower decline rates are sustainable. In our view after such “step-changes” in performance there are limits to how much further production efficiency can improve and mask underlying decline rates.

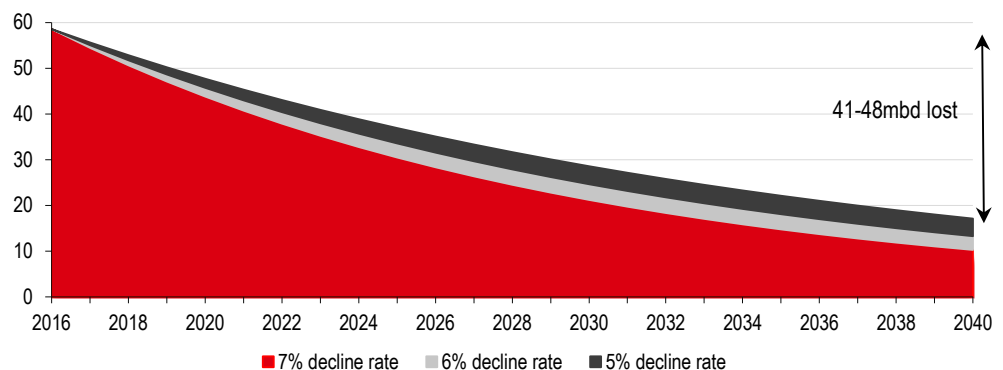
#### What it all means for global supply

Based on our supply model, we estimate that 81% of world liquids production is already in decline, excluding future redevelopments. However, on a more benign definition we estimate the figure at 64%, or 59mbd vs global supply (excluding biofuels/processing gains) of 91mbd.

The remainder of output is accounted for by 1) new conventional fields or large fields in ramp-up or plateau, 2) natural gas liquids (~13.5mbd globally, where production is often associated with long-plateau gas output, typically for LNG), tight oil (~5mbd) and biofuels (~2.3mbd).

If we assume 5-7%pa decline rates on a benign estimate of 59mbd of global post-peak output, the supply lost between 2016 and 2040 amounts to 41-48mbd. For context, this is broadly 4x the current crude oil output of OPEC's largest producer, Saudi Arabia (c.10.5mbd). Assuming all other pre-peak production is held constant, this is the amount *needed just to keep supply flat*. To provide in addition for the expected rise in global demand over the period, the additional supply needed could be closer to 55-60mbd.

#### Post-peak production (benign definition) – sensitivity to 5-7% decline rate to 2040



Source: HSBC estimates

In this report we focus on conventional liquids supply (onshore, offshore and deepwater) and do not discuss the topic of US shale declines in detail. For more on US shale trends, please see our latest Oil Insights report: [Oil Insights: The dog days of summer](#) (10 August 2016).



# Declines and the oil market

- ▶ Decline rates key to oil supply picture; and set to become an issue for investors as spare capacity tightens again in 2017e-18e
- ▶ Declines on conventional production (ex-shale) means non-OPEC production won't grow from 2016e to 2020e
- ▶ In the longer-term, a supply squeeze is likely to happen well before oil demand peaks

## Global oil market: from supply surplus to supply deficit?

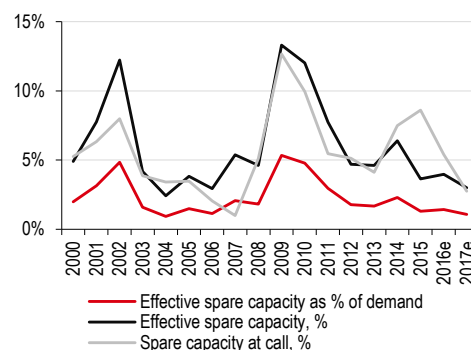
After a period of oversupply in 2014-16, the oil market is finally getting closer to balance. Our supply/demand model points to a market in balance in 2017 despite our below-consensus demand growth assumption (+0.9mbd), as non-OPEC output declines for a second successive year (-0.5mbd). Thereafter, through 2018-20 we see a steadily tightening market under a combination of demand growth, moderately rising OPEC output (mainly Iraq/Iran) but virtually flat non-OPEC volumes.

### Spare capacity to tighten in 2017e-18e

The current global oversupply has meant that the issue of decline rates have received very little investor attention in the past couple of years. However, the oil market should be back in balance sometime in 2017. At that stage, effective (ie deliverable) global spare capacity could be as little as 1% of global oil demand according to the US EIA.

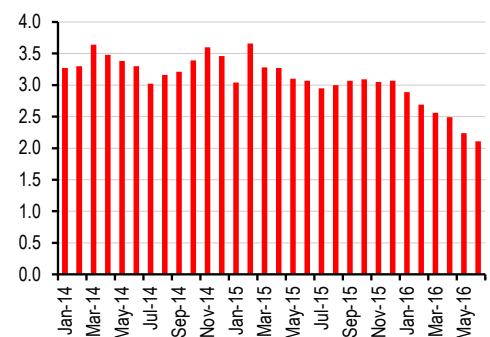
**With low spare capacity, market may worry again about supply declines**

### Measures of OPEC spare capacity



Source: BP, IEA, US EIA, Wood Mackenzie, HSBC and US EIA estimates

### OPEC ex Iraq, Nigeria and Libya spare capacity, mbd



Source: IEA

Against a backdrop of such limited spare capacity, supply shocks have the potential to significantly affect oil supply and therefore oil prices. Production declines caused by natural factors (i.e. reservoir depletion) and lack of capital investment could also become more prominent issues for the market.

### Supply issues likely to arise long before demand peaks

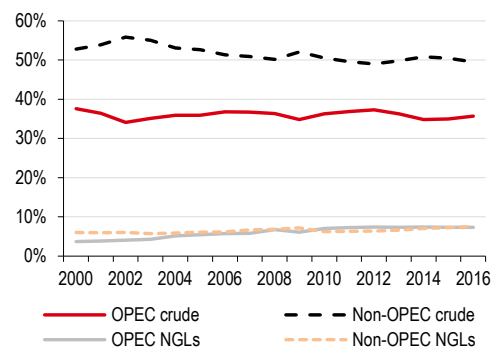
With respect to the long-term outlook for oil, investors' concerns seem mostly focused on the outlook for oil demand. This is understandable, particularly in the context of the COP21 agreement and rapid advances in alternative energy technologies such as electric vehicles. As discussed later in this report (page 16) and in detail in [Global oil demand: Near-term strength, longer-term uncertainty](#) (24 July 2016), none of the central scenarios from the main energy agencies (such as the International Energy Agency, the US Energy Information Administration and OPEC) and oil majors currently sees global demand peaking by 2040. The average growth in oil demand over the period is seen at ~15mbd.

Even in a world of slower oil demand growth, we think the oil industry's biggest long-term challenge is to offset declines in production from mature fields. The scale of this issue is such that in our view rather there could well be a global supply squeeze some time before we are realistically looking at global demand peaking.

### Non-OPEC conventional crude production has struggled to grow

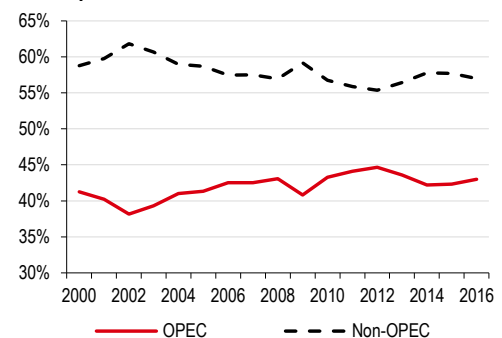
For context, global liquid supply is currently ~96mbd, up from the recent low of ~85mbd in 2009 after the global financial crisis. Of this, ~56mbd is non-OPEC, including 7mbd of natural gas liquids (NGLs), plus 2.3mbd of biofuels – which leaves around 47mbd of non-OPEC crude production (including processing gains). OPEC crude represents around 33mbd and OPEC NGLs another 6.7mbd.

#### Share of global liquids production



Source: Bloomberg, Petroleum Intelligence Weekly (PIW)

#### Share of global liquids production (crude + NGLs)

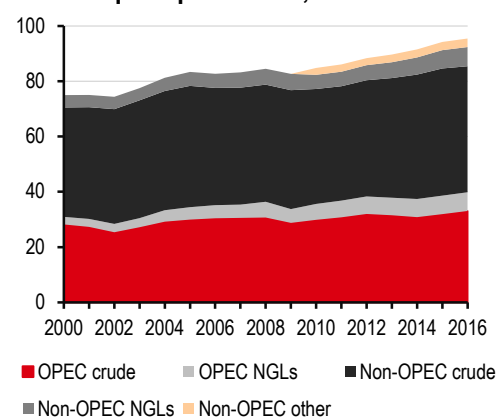


Source: Bloomberg, Petroleum Intelligence Weekly (PIW)

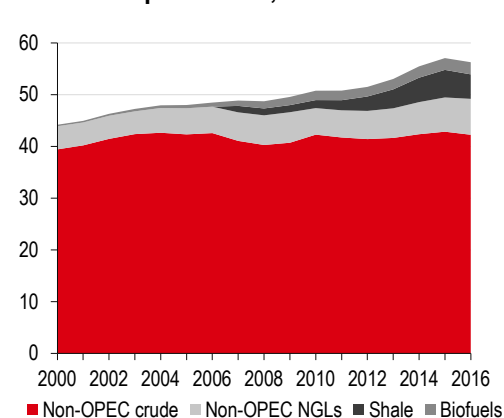
It is useful to understand the contributions to the incremental 11mbd of liquids since 2009 by the various producer categories:

- ▶ **OPEC** contributed around 3.1mbd of growth (mainly from Saudi Arabia and Iraq), and the cartel's market share fell slightly from 34.9% to 34.2%. Natural gas liquids (NGLs) from OPEC also grew strongly, adding about 1mbd over the period.
- ▶ **Non-OPEC** contributed a total of 6.7mbd of incremental supply over the period. This may look like a good performance at first glance, but most of this volume growth came from supply sources outside conventional crude. Non-OPEC NGLs (which are related to gas and LNG output), US shale and biofuels added 1mbd, 3.4mbd and 0.8mbd respectively. In fact, non-OPEC conventional crude production grew by only 1.5mbd over 7 years, equivalent to a growth rate of just 0.5% – well below trend demand growth. This isn't a new trend: if we go back a little further, non-OPEC conventional crude is currently no higher than it was ten years ago.

Global liquids production, mbd



Non-OPEC production, mbd



The lack of growth in non-OPEC conventional crude production is deeply unimpressive considering the rise in oil prices since 2000 and the associated increase in upstream capital investment over the period. In light of the halving of industry capex since 2014, it is unlikely that non-OPEC conventional crude output growth will do much better than in the past 15 years.

In this report, we are seeking to address the potential reductions in the main engine of global liquids production. This means production from conventional onshore, shallow-water offshore and deepwater reservoirs.

**Note:** We do not discuss the topic of US shale declines in detail in this report, as we choose to focus on conventional production (onshore, offshore and deepwater) rather than shale or heavy oil. For context, US shale currently represents 4.6mbd of liquids output, down from a peak of ~5.5md in March 2015. This represents around 8% of total non-OPEC production and 5% of world supply.

For more on US shale trends, please see our latest Oil Insights report: [Oil Insights: The dog days of summer](#) (10 August 2016), pages 10-11 and 24-26. We intend to follow up with another thematic report focusing on US shale later this year.



## HSBC oil supply & demand model and oil price assumptions

### Flat non-OPEC supply from 2016e to 2020e

We think the market could be underestimating the scale of the supply tightening and the almost unprecedented fall in industry investment seen in the past two years is likely to have long-term implications for the supply outlook. Despite our expectation of a rebound in US tight oil output from H2 2017 onwards as prices rise further, we see total non-OPEC output no higher in 2020e than in 2016e. Moreover, the effects of the spending slowdown on non-OPEC supply are likely to stretch far beyond 2020, in our view.

### Global oil supply/demand balance, mbd

	2013	2014	2015	2016e	2017e	2018e	2019e	2020e
<b>Demand</b>								
OECD	46.0	45.8	46.2	46.4	46.3	46.1	45.9	45.7
Non-OECD	45.4	46.7	47.8	48.8	49.8	50.9	51.9	53.0
<b>Global demand</b>	<b>91.3</b>	<b>92.4</b>	<b>94.0</b>	<b>95.2</b>	<b>96.1</b>	<b>97.0</b>	<b>97.8</b>	<b>98.6</b>
Demand growth	1.0%	1.2%	1.7%	1.2%	1.0%	0.9%	0.8%	0.8%
<b>Supply</b>								
Non-OPEC*	53.0	55.5	57.1	56.3	55.8	56.2	56.0	56.0
OPEC NGLs	6.4	6.4	6.5	6.7	6.9	7.0	7.1	7.2
<b>Non-OPEC &amp; OPEC non-crude</b>	<b>59.5</b>	<b>61.8</b>	<b>63.6</b>	<b>62.9</b>	<b>62.7</b>	<b>63.2</b>	<b>63.2</b>	<b>63.2</b>
<b>OPEC crude production</b>	<b>31.7</b>	<b>31.0</b>	<b>32.1</b>	<b>32.7</b>	<b>33.3</b>	<b>33.5</b>	<b>33.9</b>	<b>34.3</b>
<b>Global supply</b>	<b>91.2</b>	<b>92.8</b>	<b>95.7</b>	<b>95.6</b>	<b>96.0</b>	<b>96.7</b>	<b>97.1</b>	<b>97.5</b>
<b>Implied inventory build/(draw)</b>	<b>-0.2</b>	<b>0.4</b>	<b>1.7</b>	<b>0.5</b>	<b>-0.1</b>	<b>-0.3</b>	<b>-0.7</b>	<b>-1.1</b>
Call on OPEC crude	31.9	30.6	30.5	32.2	33.4	33.8	34.6	35.4
OPEC crude capacity, mbd	33.2	33.1	33.4	34.1	34.4			
Spare capacity at call, mbd	1.4	2.5	2.9	1.8	0.9			
Spare capacity at call, %	4.1%	7.5%	8.6%	5.4%	2.8%			
Effective spare capacity, mbd	1.53	2.11	1.21	1.36	1.03			
Effective spare capacity, %	4.6%	6.4%	3.6%	4.0%	3.0%			
Spare capacity at call, % of demand	1.5%	2.7%	3.1%	1.9%	1.0%			
Effective spare capacity, % of demand	1.7%	2.3%	1.3%	1.4%	1.1%			
<b>Annual changes, mbd</b>								
Global demand	0.9	1.1	1.6	1.1	0.9	0.9	0.8	0.8
Non-OPEC supply	1.5	2.4	1.6	-0.8	-0.5	0.4	-0.1	-0.1
Non-OPEC (inc. OPEC NGL) supply	1.5	2.4	1.7	-0.6	-0.3	0.5	0.0	0.0
Call on OPEC	-0.6	-1.3	-0.1	1.7	1.2	0.4	0.8	0.8
OPEC crude production	-0.9	-0.7	1.2	0.6	0.6	0.2	0.4	0.4

\*Includes global biofuels, processing gains etc.

Source: BP, IEA, US EIA, Wood Mackenzie, HSBC estimates

### We continue to assume Brent crude prices of USD60/b in 2017e, USD75/b in 2018e

As a result, we see the stage set for further crude price upside as the market steadily tightens through the remainder of this decade. Our unchanged Brent price assumptions are USD60/b in 2017e and USD75/b in 2018e.

### HSBC oil and natural gas price assumptions

Annual average		2011	2012	2013	2014	2015	2016e	2017e	2018e
Brent	USD/b	110.9	111.7	108.7	99.5	53.6	46.8	60.0	75.0
WTI	USD/b	95.1	94.1	97.9	93.1	48.7	45.5	59.0	74.0
W Canada Select	USD/b	78.4	71.8	73.5	74.4	35.7	29.0	42.0	52.5
Dubai	USD/b	106.1	108.9	105.4	96.6	51.2	43.2	57.0	72.0
Nymex gas	USD/mBtu	4.0	2.8	3.7	4.3	2.6	2.5	3.0	3.5
UK spot gas	GBp/th	56.4	59.7	68.2	50.2	42.7	31.5	40.0	50.0

Source: Bloomberg, HSBC assumptions

# Decline rates – synopsis

- ▶ Decline rates likely to rise over time as oil production relies increasingly on small fields
- ▶ Range of 5-7% for global decline rates seems sensible based on academic studies and our own analysis
- ▶ Improved production & drilling efficiency can stem declines, but only for so long – as the North Sea example shows

## What's in this report

Oil is geologically different from other commodities in that production is not naturally static: after a period of plateau, all oil and gas fields inevitably decline even with additional investment. There is therefore a natural correcting mechanism in global oil supply. While the impact of decline on long-term oil supply is well-known, the exact mechanics and behaviour of decline rates are not necessarily as well understood by the market, in our view.

This report looks in detail at two main subjects:

1. The theory and practice of decline rates, and the scale at which this can affect future oil supply.
2. Improving production efficiency, and how this is mitigating declines, but potentially only temporarily.

## Decline rates likely to rise

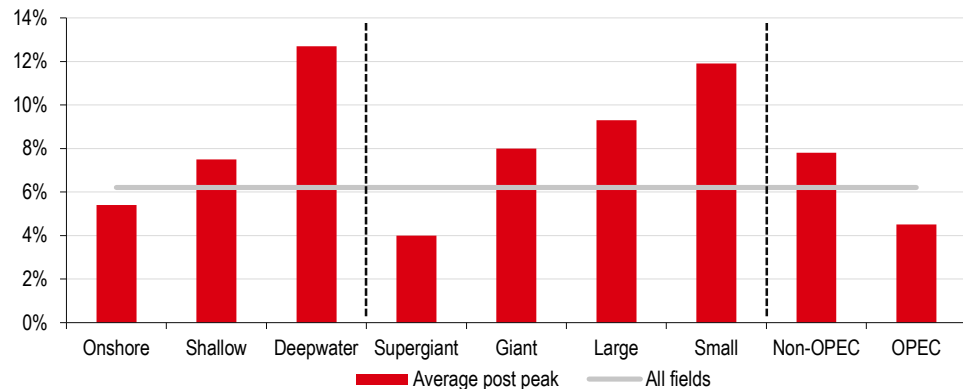
In this report, we look at the theory and practice of decline rates. We have reviewed several academic studies on declines, notably i) the IEA study from the 2008 and 2013 editions of its annual World Energy Outlook and ii) the University of Uppsala (Sweden) papers published in 2009 and 2013. The IEA and Uppsala studies were based on the analysis of over 1,600 fields (covering two-thirds of global oil production) and just under 900 fields respectively – large enough to be statistically significant.

### How quickly is production declining?

The studies we have compiled (IEA and Uppsala) coincidentally appear to agree on a ~6.2% average post-peak decline rate. Decline rates are higher for offshore fields and smaller fields, reaching 12% or more for deepwater fields and for fields of less than 100mbbls. The chart below shows the IEA's average post-peak decline rate calculations for various field categories and sizes:

**Studies converge on a >6%  
post-peak decline rate**

## Annual decline rates for various field types and sizes



Source: IEA World Energy Outlook 2013. Average declines are weighted by cumulative production to 2012. Decline rates are calculated as compound-annual decline rates since peak.

#### 5 observations on decline rates' behaviour

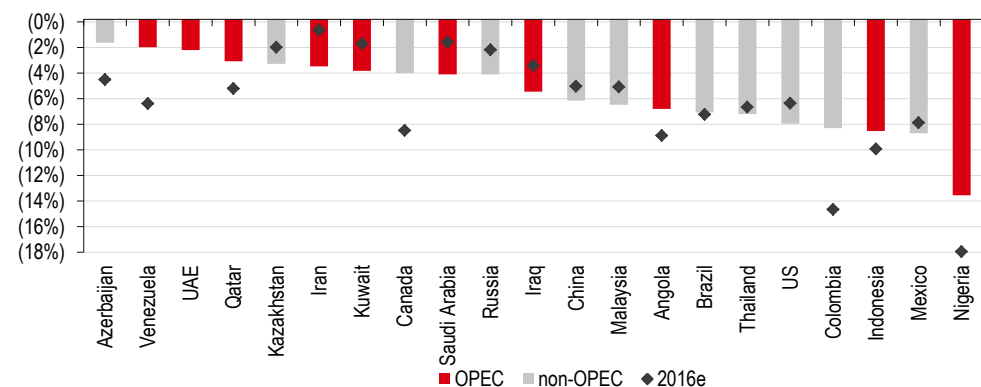
The studies highlight several important conclusions on decline rates:

- ▶ **Offshore fields decline 3-6 ppts faster than (conventional) onshore fields.** This is partly because offshore fields are smaller than onshore fields, on average. This leads to the next observation:
- ▶ **Smaller fields decline substantially faster than large fields.** This will have important implications for future world supply as the giant fields are maturing and a rising amount of global oil production is coming from small fields (see more on this in the next section on page 16).
- ▶ **World decline rates have been slowly increasing:** for instance, non-OPEC giant fields that peaked in the 2000's are declining at ~10% p.a., vs <5% for fields that peaked in the 1970's. This deterioration reflects several factors including the diminishing size of new giant fields, deteriorating geology and finally the impact of technology. Secondary and tertiary recovery (IOR/EOR) techniques play a crucial role in the oil supply equation and help to support global oil output, particularly for large fields where they are more frequently applied. However, studies show that technology not only increases reservoir recovery rates, but also brings production forward in order to keep output relatively flat. This leads to higher decline rates at the back end of the curve, once all the "tricks in the book" have been exhausted and fields actually start declining.
- ▶ **Decline rates accelerate in the final stages of a field's lifecycle.** This is particularly the case for giant fields due to the impact of enhanced recovery techniques, which do little to stem declines past a certain point. However, the IEA has shown that the conclusion holds for any size and type of field, with a ~5% average step-up in decline rates in the terminal phase (ie, when output has fallen to less than 50% of peak) compared to earlier phases.
- ▶ **Basin-wide decline rates inevitably catch up with field decline rates.** Basin declines are typically much lower than individual field decline rates, but rise as basins mature and the new field start-ups needed to offset basin declines get increasingly small. It can take 30 years or more for basin-wide declines to reach individual field decline rates.

We have calculated underlying decline rates based on our analysis of Wood Mackenzie data covering over 6,000 fields and 21 countries representing 86% of world crude supply. In order to smooth out annual volatility, we use 20-year compound average decline rates (1996-2016e) rather than single-year decline rates.

- ▶ We find that decline rates range between -14% at worst (Nigeria) to -2% at best (Azerbaijan), with a global average around 6%.
- ▶ Unsurprisingly, OPEC countries tend to fare better on average than non-OPEC countries on decline rates. There are a few notable exceptions such as i) Nigeria, where militant attacks have been responsible for significant output losses, and ii) Indonesia and Angola, both of which are offshore producers as opposed to the onshore Middle East OPEC producers.
- ▶ By and large, decline rates appear to have accelerated slightly in 2016e compared to their 20-year average. Having said this, we would not focus too much on single-year decline rates given year-on-year volatility in output.

Compound-average underlying decline rate by country, last 20 years



Source: HSBC estimates, Wood Mackenzie. NB: Excludes NGLs and unconventional shale production in the US and Canada.

## The North Sea example

### Detailed analysis of North Sea data backs up the theory

In this report, we analyse data and use examples from the North Sea in order to test and back up the theories laid out in academic studies. The North Sea is a mature OECD oil producing offshore region where data is more easily available than most other regions. The region used to represent 9% of global production in the 1990's, but this has since fallen to just 3%. While we have analysed in detail here only two countries (UK and Norway), we believe many of the conclusions drawn from our North Sea analysis can be extrapolated to other regions, particularly as they relate to offshore production.

Our North Sea analysis reveals the following:

- ▶ Since 1997, the managed country-level decline rate has averaged 5% pa and 8% pa in Norway and the UK, respectively, compared to 9% and 14% for "natural" decline rates.
- ▶ Managed decline rates have improved noticeably in the last couple of years thanks to rising production efficiency.
- ▶ Basin-wide declines are far lower than individual field decline rates, which we estimate at 10% in Norway and 12% in the UK. Models show that basin-wide decline rates should slowly converge towards (higher) field decline rates over time.
- ▶ Small fields decline noticeably faster than larger fields. Moreover, large fields (>500mbbls) have relatively stable decline rates in the first 15 years of their lives, then show accelerating declines at the end of their lives – consistent with the behaviour predicted by academic studies.

- ▶ The average size of new field start-ups has trended down over the last 40 years, dropping from over a hundred million barrels before 2000 down to 42mb in Norway and a measly 15mbbls in the UK in the last five years. Both countries are much more reliant on the contribution from smaller (and therefore faster-declining) fields than 20 years ago.
- ▶ Average water cuts have risen to 80% in the UK and to 62% in Norway. Water cuts tend to rise faster for small fields and typically cause earlier shutdowns than at larger fields. Almost a third of all UK production has a water cut of over 75%.
- ▶ Based on Norway's example, decline rates are faster for crude than NGL production, as the latter is also linked to often more stable gas output. This may well be the only mitigating factor in an otherwise bleak picture for decline rates, as NGL production from both OPEC and non-OPEC should continue to rise and make up a greater production of world liquids supply.

## The impact of improving plant and drilling efficiency

Greater production efficiency explains higher-than-forecasted supply...

In many parts of the world, oil production has surprised to the upside since the start of the oil price downturn in 2014. Putting aside the specific case of US light tight oil, the main positive surprises have come from the likes of Russia and the North Sea, both of which managed to grow output last year against expectations. Both are mature oil producing regions where, unlike the US shale patch, there are no obvious technological or geological game-changers.

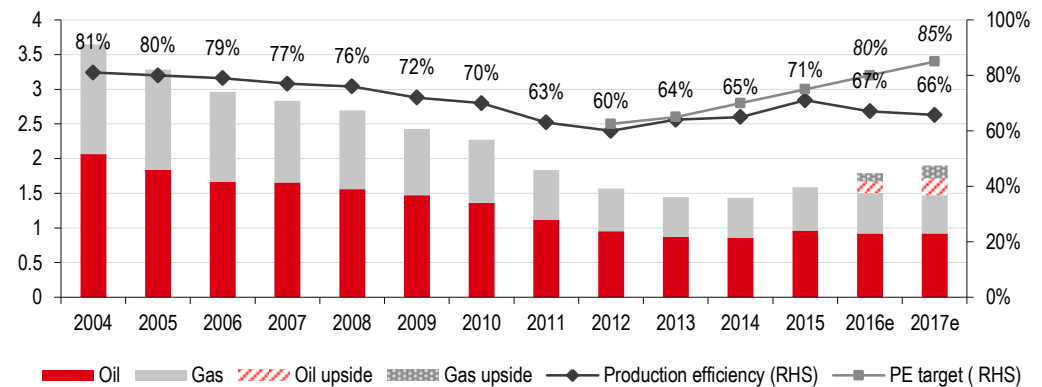
In this report, we examine the topic of production efficiency ("PE") and drilling productivity closely, using examples from the North Sea. Production efficiency measures actual production relative to the maximum production potential of a field. The concept of PE is particularly relevant for offshore activities, where fixed costs are high and maximising platform availability is therefore crucial to production economics.

... But there are limits to how much it can improve further

We conclude that production and drilling efficiency have played a major part in the unexpectedly strong output increase seen in the last two years in the UK and Norway. While improvements have been impressive – particularly in previously poor-performing regions such as the UK side of the North Sea – we believe there are limits to how much production efficiency can improve further and mask underlying decline rates. Notwithstanding anecdotal evidence of individual fields reaching 97-99% production efficiency rates, we think the natural limit for production efficiency is probably around 90-92% across an entire upstream portfolio and over a full maintenance cycle.

- ▶ In the **UK**, production efficiency fell steadily for a decade from 81% in 2004 to mediocre 60% in 2012, and has since rebounded to 71% in 2015 – about halfway back to where it used to be. If we assume a similar rate of improvement in 2016-17e to that seen in the last 3 years, we estimate that there could be up to 110kbd of production upside relative to the IEA's 2017e production forecasts (or 11% of the country's expected production).

### UKCS Oil & gas production efficiency



Source: UK Oil & Gas Authority, HSBC estimates

- ▶ **Norway** is already well ahead of the UK on production efficiency. Statoil, a reasonably good proxy for Norwegian production, reported over 90% production efficiency last year across its Norwegian operations. This means there is less scope to further improve performance relative to the UK. Indeed Statoil aims to keep production efficiency at a similar level this year, acknowledging that further meaningful improvements are unlikely.
- ▶ **Drilling productivity** has improved dramatically in the last 2-3 years and has helped to offset the decrease in drilling spending and the number of rigs in operations. In Norway, development wells are now 50% cheaper than 3 years ago, leading to higher drilling activity despite lower investment.

### New oil fields are becoming smaller

Fields are becoming smaller globally

The average size of new oil fields matters in at least two respects.

- ▶ Firstly, basin-wide decline rates ultimately catch up with individual field decline rates *only under the assumption that new fields get smaller over time*.
- ▶ Secondly, smaller fields decline significantly faster than big fields as discussed above. For instance, giant fields (>1bnbbbls) typically decline at less than 5% p.a. while small fields of under 100mmbbls decline at 20% or more.

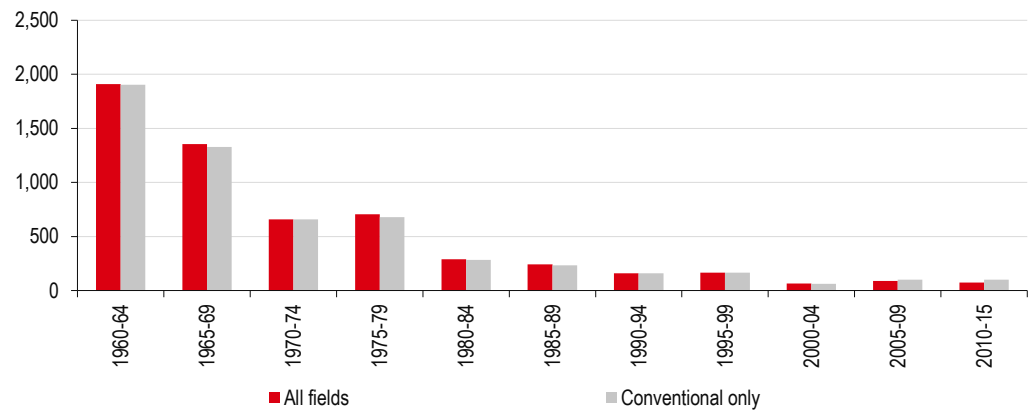
On the scale of hydrocarbon basins, oil field discoveries and start-ups generally do get smaller over time: the larger fields are logically found and developed first, so the frequency and average size of new discoveries tends to diminish as basins get more mature over the years.

New fields starting up are getting smaller; <80mmbbls now the norm

Based to our analysis of Wood Mackenzie data covering 15,500 fields, the average size of new field start-ups has dropped significantly from over a billion barrels in the 1960's to ~250mmbbls in the 1980's to just 75mmbbls this decade.



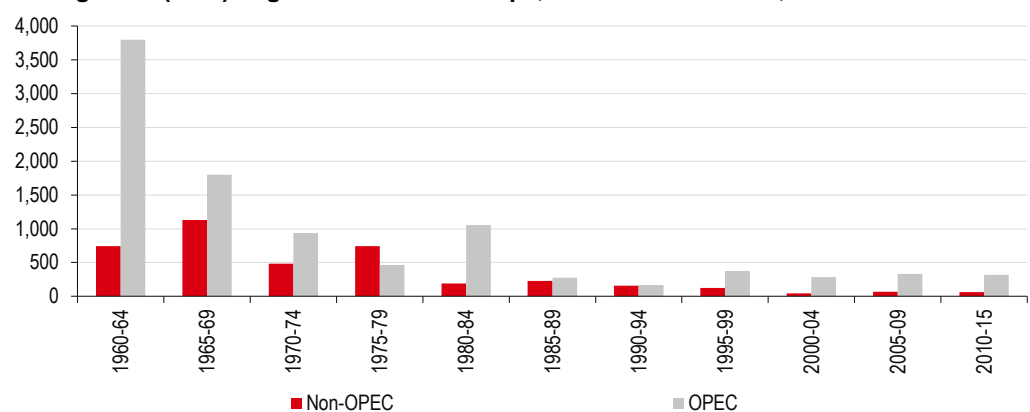
**Average size (URR) of global oil field start-ups, mboe**



Source: HSBC estimates, Wood Mackenzie

The conclusion is even worse when looking just at the non-OPEC world, where the average size of new field start-ups has fallen to 64mmbbls.

**Average size (URR) of global oil field start-ups, OPEC vs non-OPEC, mboe**



Source: HSBC estimates, Wood Mackenzie. NB: Conventional resources only

In truth, the average size of new start-ups has been broadly stable since 2000 at less than 100mmbbls, so these are not exactly new trends. However, the ever-decreasing size and number of new oil discoveries does not bode well for future oil field start-ups.

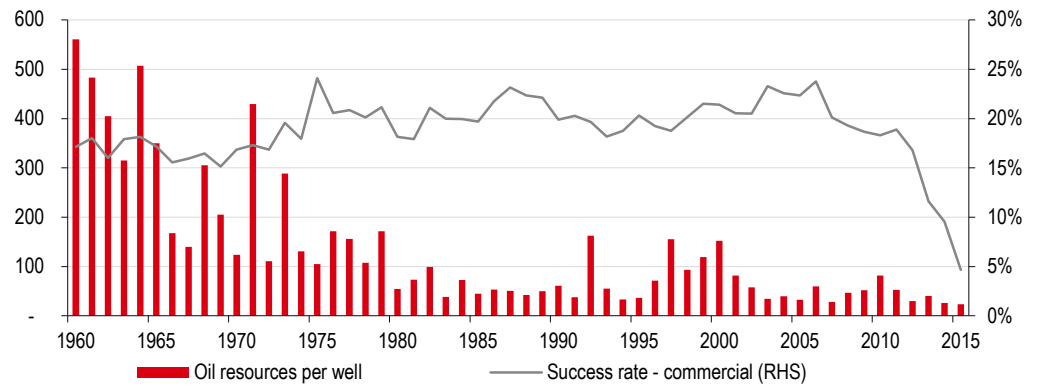
### No sign of improvement in oil discoveries

The size of oil discoveries has also been steadily diminishing over the years, fully consistent with our earlier findings on field start-ups. Oil fields typically start up within 5-15 years of discovery, so trends related to discoveries should simply anticipate those for producing fields with a time lag.

According Wood Mackenzie, the average size of oil discoveries has steadily declined over time and reached an all-time low in 2015 of just 24mmbbls of oil resources per discovery well. For context, this compares to 340mmbbls in the 1960's and 180mmbbls in the 1970's, and is equivalent to 18% of the historical annual average since 1960.

**Oil discoveries are also smaller and fewer**

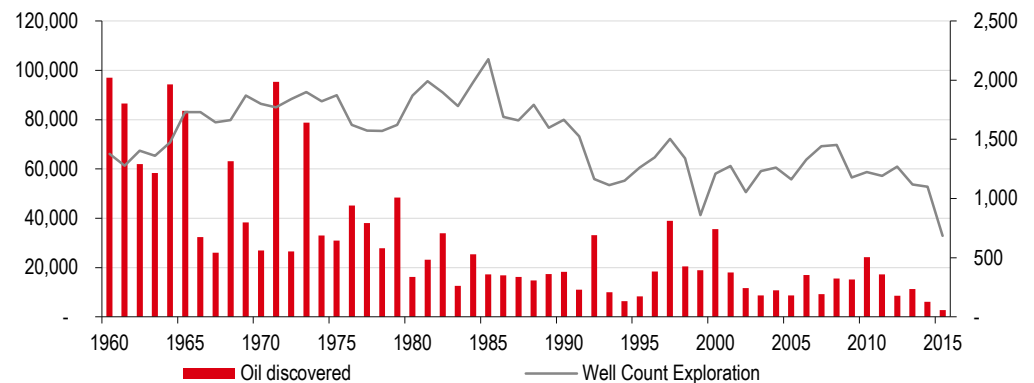
### Oil resources per discovery well (mbbls) and success rate (%)



Source: Wood Mackenzie, HSBC estimates

When looking at exploration activity in aggregate rather than at the individual discovery level, we also observe that: 1) the number of exploration wells spudded has dropped markedly in the last couple of years, and 2) the exploration success rate has plummeted to an all-time low of 5%. As a result, the *absolute amount of oil discovered* fell to just 2.7bnbbls, 9% of the historical average.

### Total oil discovered (mbbls) and number of exploration wells (RHS)



Source: Wood Mackenzie, HSBC estimates

In conclusion, the data shows that oil fields do get individually smaller on average, and that new discoveries are also smaller than in the past. It also shows that there are fewer discoveries as the number of exploration wells drops and success rates worsen. It follows that average field declines rates should increase over time as global production increasingly relies on a high number of small fields and less so on big fields.

## What does this all mean for global supply?

### How much of global production is declining?

>80% of world oil supply  
already post-peak, on strict  
definition

Based on our oil supply model, we estimate that **~81% of world oil supply** (crude and NGLs) **is post-peak, or ~74mbd out of ~91mbd of production** (excluding biofuels and processing gains). In this analysis, we have used the strictest definition of “post-peak production”, defined as output from all fields that are currently (as of 2016) below a previous production peak.

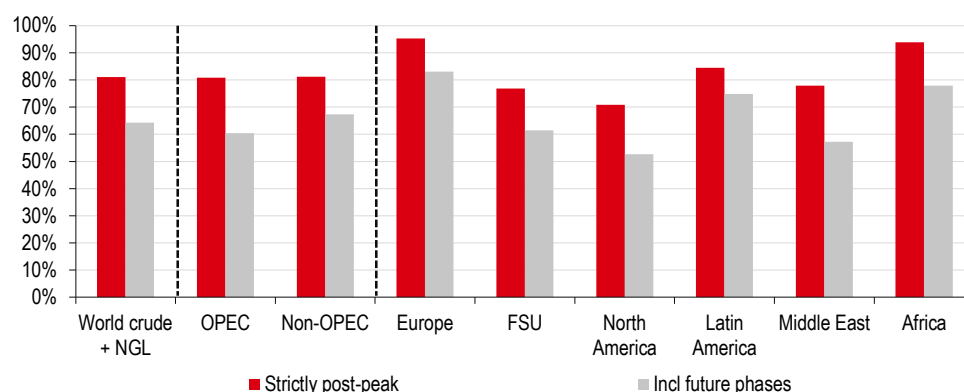
However, a less restrictive definition of “post-peak production” can be used, whereby we consider that fields which have previously peaked but will have a second production peak (or redevelopment) in the future are not post-peak. This is particularly relevant for large onshore fields, which are more easily developed in successive phases, with sometimes lengthy intervals between investment phases. For example, we classify the Tengizchevroil giant project in Kazakhstan as “growth” rather than “post-peak”, as it is will undergo a big expansion phase from 2019 onwards. In our view, both definitions of post-peak production are equally valid and have their own use, as many fields which will be redeveloped in the future are currently suffering from decline.

On less strict definition, <2/3  
of supply is post-peak

**Using the more benign definition, we find that 64% of the world's oil production is post-peak, or ~59mbd.** As should be expected, the largest differences between the strict and less strict definitions are found in the US (due to the expected recovery in tight and shale oil output from 2018 onwards), Russia, Kazakhstan (due to the Tengizchevroil expansion), OPEC countries (especially Iran, Iraq and Saudi Arabia) and countries where large production disruptions have occurred in 2016 (e.g. Libya, Nigeria).

In conclusion, even using the less strict definition, it is clear that many producing regions are highly mature, particularly Europe, Africa and Latin America. North America appears to be the least mature region of the world, with 47% of current output which is either long-plateau production (e.g. Canadian heavy oil) or yet to reach a production peak (e.g. US light tight oil from the Permian, Eagle Ford etc).

### Post-peak world oil production, as % of total



Source: HSBC estimates, BP Statistical Review of World Energy 2016. Includes crude and NGLs.

### Global production is sensitive to small changes in decline assumptions

1% change in initial decline  
rate assumption = 4-5mbd  
difference by 2040

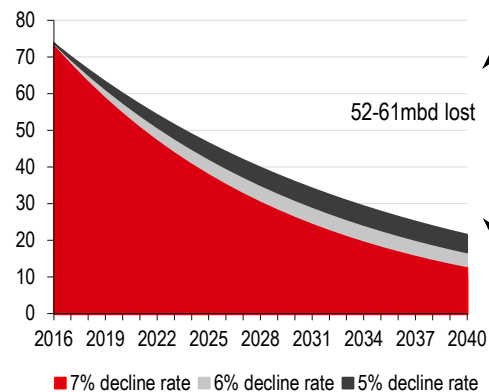
If we assumed an average decline rate of 5%pa on global post-peak supply of 74mbd – which is by no means aggressive in our view – it would imply a fall in post-peak supply of c.38mbd by 2030, and c.52mbd out to 2040. In other words, the world would need to find over four times the size of Saudi Arabia just to keep supply flat, before demand growth is taken into account.

**4 or 5 new Saudi Arabia's  
needed by 2040 just to keep  
supply flat**

Given the compounding nature of oil decline rates, a small difference in the initial decline rate assumptions makes a significant difference to long-term production forecasts 20 years down the line. For instance, if we assumed a 6% pa global decline rate instead of 5%, we would need to find 57mbd of new capacity. At a 7% decline rate, we would need 61mbd of new capacity, or around five "Saudi Arabias".

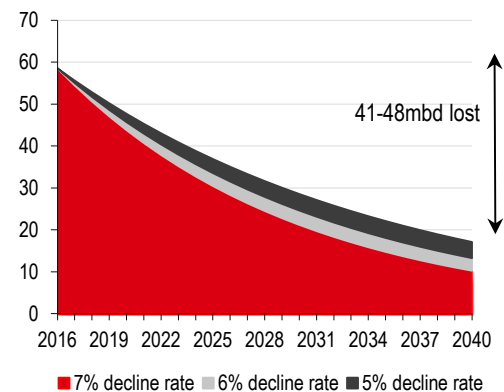
For a more benign view, we could use the less strict definition of post-peak production of 59mbd as a starting point. A decline rate of 5-7% would lead to a fall in post-peak production of 41-48mbd. These are still very large numbers that represent a huge supply challenge to the oil & gas industry.

**Post-peak production (strict definition) – sensitivity to 5-7% decline rate to 2040**



Source: HSBC estimates

**Post-peak production (benign definition) – sensitivity to 5-7% decline rate to 2040**



Source: HSBC estimates

We could indeed use the more benign definition of post-peak production, however we believe that using a constant decline rate between now and 2040 could be too optimistic. As previously discussed, decline rates should rise over time as new fields get increasingly small.

**While the concept of decline may be eminently simple to grasp, the quantification of decline rates is of crucial importance in our view.** Whether the answer is 5% or 7% really does matter to oil supply and ultimately to oil prices.

## Oil demand is growing, despite near-term concerns

**Oil demand is still growing at  
0.8-1.1mbd p.a.**

Although there might be some very near-term concerns about demand, the medium-term outlook to 2020e looks robust. We expect global oil demand growth of 1.1mbd (1.2%) in 2016e, still above the ten-year average of 0.9mbd. We then expect demand to return broadly to trend (0.9mbd) in 2017e-18e. Thereafter, rates of demand growth are set to slow further, and we forecast 0.8mbd p.a. growth in 2019e-20e.

Following the COP21 agreement and in the context of rapid advances in alternative energy technologies, uncertainties over the long-term outlook for oil demand seem to have increased significantly. With this in mind, we recently conducted a detailed review of a number of leading long-term energy demand scenarios and their implications for long-term oil demand. For full details, please see [Global oil demand: Near-term strength, longer-term uncertainty](#), 24 July 2016.

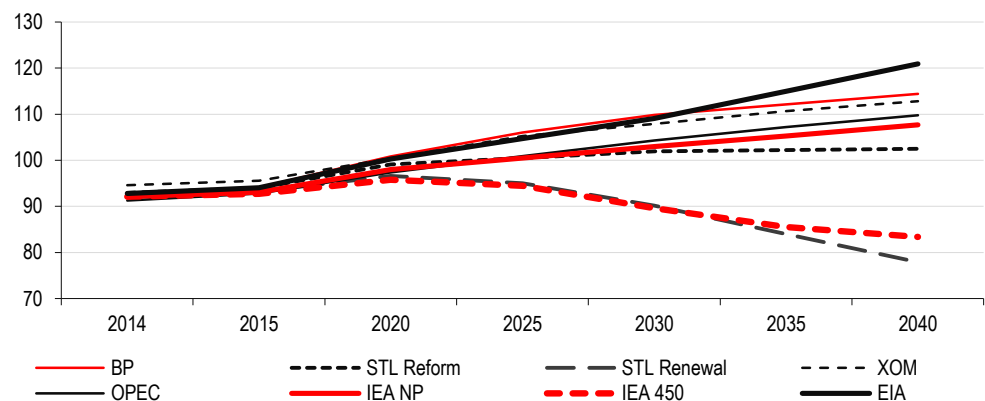
Much of the debate around long-term prospects for oil demand is dominated by the issue of penetration of the light duty vehicle (LDV) fleet by electric vehicles (EVs). Of course this is one of the key uncertainties, but there are a few other important points to highlight:

- ▶ It's not all about cars: LDVs are only responsible for around a quarter of world oil demand.
- ▶ Other forms of transport (trucks, aviation, marine and rail) consume in total more than LDVs, and although substitution is happening, widespread disruption on the potential scale facing LDVs look far less achievable, in our view. Demand growth prospects for both aviation and commercial trucks look extremely strong across all the reference scenarios we assessed, driven mainly by non-OECD markets.
- ▶ Petrochemicals demand currently accounts for around 13% of global oil demand and has been a key source of growth; aggregate chemicals demand growth of ~50% (6mbd) by 2040e looks quite feasible from the studies we examined.

**Oil demand grows through to 2040 in all reference cases**

Across the range of the scenarios we studied, none of the “reference cases” point to a peak in oil demand through the forecasting period (to 2040), and even the most conservative of these studies points to 2040e global demand more than 8mbd above that of 2015.

**Global liquids demand, 2014-40e, mbd**



Source: BP, ExxonMobil, Statoil, IEA, EIA, OPEC. Note that STL Renewal and IEA 450 are outcomes-based scenarios consistent with limiting temperature rises to 2°C

# Decline rates and oil supply

- ▶ All oil fields decline, but small and offshore fields decline much faster than large and onshore fields
- ▶ Rising proportion of world supply is coming from small fields
- ▶ Case studies from North Sea to China show technology (IOR/EOR) initially limits decline rates, but helps little past a certain stage

## Defining decline rates

Let's start with a few definitions. The **decline rate** is usually defined as the amount of liquids production lost in a given year divided by last year's output, yielding a (negative) percentage change.

$$\lambda_n = \text{Decline rate}_n = \frac{\text{Production}_n - \text{Production}_{n-1}}{\text{Production}_{n-1}}$$

The decline phase in an oil field occurs after production has reached its peak. In the case of large fields, peak production tends to last longer than for smaller fields – in many cases, several years – and decline only sets in after a multi-year plateau.

The term “decline” can be applied at various levels of aggregation such as individual wells, fields, basins and countries. When applied to a region, we should distinguish between the *overall* decline rate which includes all producing fields, and the *post-peak* decline which only includes fields already in decline and excludes fields that are ramping up or still at plateau.

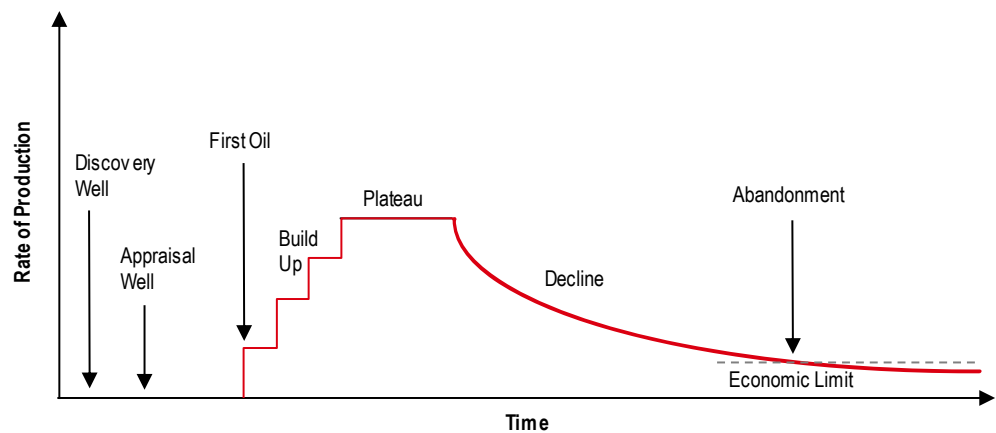
Production decline can be caused by a number of factors, generally categorised as either “above-ground” or “below-ground”:

- ▶ Above-ground (or man-made) factors include production constraints, technical failures, sabotage, permitting issues and politics. Despite their importance, this report will largely leave aside such considerations and focus on below-ground factors.
- ▶ The main below-ground factor is natural *depletion*. At some point in their lifecycle, all oil fields begin to decline as the production of liquids (oil, condensates, and NGLs and water) leads to falling reservoir pressure, which in turn causes well flow rates to drop. Water cuts (i.e., the ratio of water to total liquids produced) also start to rise as wells produce increasing amounts of water.

Declines are one of several factors that cause oil production to decrease



Stylised oil field production curve, describing the various stages of maturity



Source: Davies, D (2001). Production technology II. Tech. rep., Department of Petroleum Engineering, Heriot-Watt University (Edinburgh, Scotland)

Natural decline rates can be mitigated through investment

Natural decline can be mitigated through investments into additional drilling, facilities, debottlenecking, secondary and tertiary recovery. Some analyses differentiate **natural decline** (which purely reflects physical factors) from **managed decline rates**, which include the impact of reinvestment. The IEA estimates that the difference between natural and managed decline rates is between 2% and 3%, and has been rising over time.

Depletion occurs from Day 1, not to be confused with decline...

Natural **depletion**, not to be confused with natural decline, occurs as soon as a field enters production. As such, a field that has recently started up is already depleting – by definition – but may not yet be in decline. Depletion measures the rate at which recoverable resources of a field or region are being produced. It is defined as the ratio of annual production to either ultimate recoverable reserves (URR), or alternatively to *remaining* recoverable resources, where the latter is calculated as ultimate recoverable resources minus cumulative production.

...but depletion and decline rates are strongly correlated

Numerous studies have shown a strong correlation between decline and depletion rates, which is hardly a surprise given the primary role of depletion in determining decline rates. In a theoretical exponential decline curve (which we discuss below), the depletion rate in fact equals the decline rate.

## Decline rate curves: the basics

Exponential decline rate model is the best-known

For the last century or so, many studies have proposed modelling decline rates as simple mathematical curves, either exponential, harmonic or hyperbolic. There is a good connection between these simplified mathematical models and the physical models for reservoir flows – for instance, the exponential model solves for the flow equation of a well with constant bottomhole flowing pressure. It is also virtually independent of the reservoir size and shape, and the actual drive mechanism.

The best-known decline rate model is perhaps the *exponential* equation, whereby:

$$P_n = (1 - \lambda) \times P_{n-1} \text{ and } P_n = (1 - \lambda)^n \times P_0$$

where  $P_n$  is the production rate in year  $n$ ;  $P_0$  is the initial production rate in year 0 (when decline starts), and constant  $\lambda$  is the decline rate. A close variant of the exponential decline formula is:

$$P_n = P_0 e^{-\lambda n}$$

**Hyperbolic decline model allows for falling rate of decline**

The *general hyperbolic* decline rate equation allows for a falling rate of decline rather than a constant rate of decline, and is written as follows:

$$P_n = \frac{P_0}{(1 + \lambda \beta n)^{1/\beta}} \quad \text{where } \beta \text{ is the curvature of decline.}$$

If  $\beta = 0$ , this is equivalent to *exponential* decline, as shown above. If  $\beta = 1$ , this reduces to *harmonic* decline:

$$P_n = \frac{P_0}{1 + \lambda n}$$

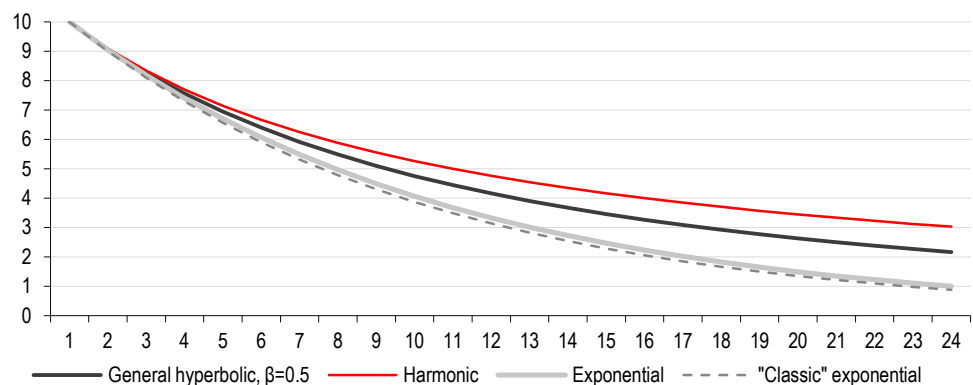
Both the exponential and harmonic are special cases of the general hyperbolic model.

Due to its simplicity and single parameter  $\lambda$ , the exponential curve is the most convenient and frequently used decline model. As we will show later, it provides a surprisingly good fit with actual production data in many cases.

However, the main drawback of the exponential decline is that it sometimes overestimates the extent of decline (i.e. underestimates production) towards the back end of the production curve, as decline often flattens out in the latter years of a field's lifecycle. This feature makes harmonic or hyperbolic curves more appropriate. Indeed, several studies (including the IEA's 2008 and 2013 studies) have split their analysis of decline rates into distinct sub-stages – we will come back to this later.

By way of illustration, we have plotted 3 decline curves in the graph below using a 10% decline rate  $\lambda$ . The harmonic and hyperbolic curves result in shallower decline rates of the order of ~4-5% towards the back end, while the exponential case maintains the decline constant at 10% throughout the field's lifetime.

**Theoretical field decline rate curves (with a decline rate factor  $\lambda$  of 10%)**



Source: HSBC estimates, based on UK Energy Research Centre: "Global Oil Depletion: An assessment of evidence for near-term peak in global oil production" (August 2009)

**Simple decline rate models fit reality surprisingly well**

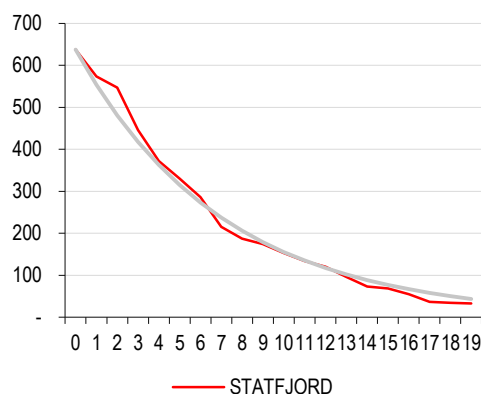
**Do these decline curves work in the real world?**

There is plenty of evidence that these simple models agree well with empirical data. To test this hypothesis, we have fitted theoretical decline curves to actual production data for several Norwegian offshore fields of varying sizes (from giants to small fields) picked at random.

During this exercise, we were surprised by i) how easy it was to find a good fit, despite some year-on-year variations, ii) the high implied  $\lambda$  (decline rate) parameters, including for large and giant fields.

**Giant field: Statfjord (1.7bn b). Exponential fit with  $\lambda = 14\%$**

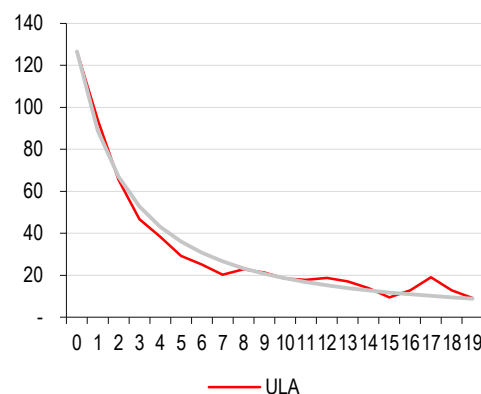
**Production (kbd) vs years from peak**



Source: HSBC estimates, Norwegian Petroleum Directorate.

**Large field: Ula (250mb). Hyperbolic fit with  $\lambda = 40\%$  and  $\beta = 0.7$**

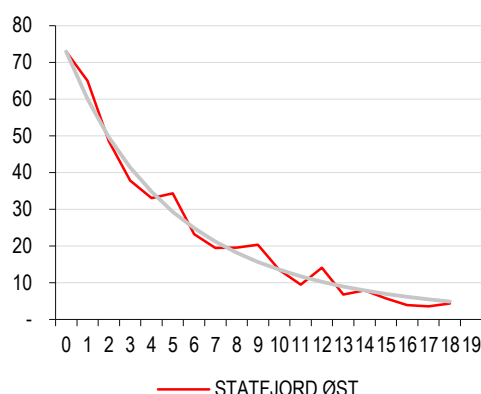
**Production (kbd) vs years from peak**



Source: HSBC estimates, Norwegian Petroleum Directorate.

**Medium/large field: Statfjord øst (162mb). Hyperbolic fit with  $\lambda = 20\%$  and  $\beta = 0.2$**

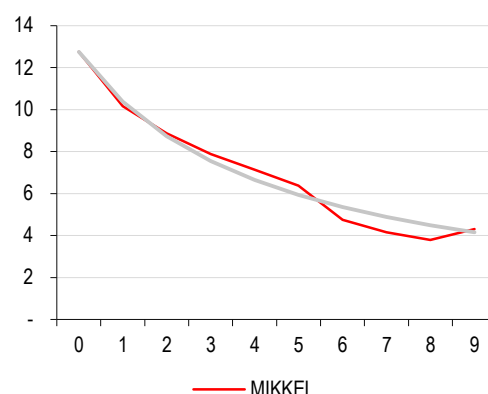
**Production (kbd) vs years from peak**



Source: HSBC estimates, Norwegian Petroleum Directorate.

**Small field: Mikkel (26mb). Harmonic fit with  $\lambda = 23\%$  and  $\beta = 1$**

**Production (kbd) vs years from peak**



Source: HSBC estimates, Norwegian Petroleum Directorate.

## Observations on decline rates from academic studies

**We summarise findings from two studies on decline rates, including the IEA's**

Several academic studies have tried to quantify global decline rates – a herculean task which requires a considerable amount of accurate production and reserve data for hundreds or thousands of fields around the world.

The main authoritative studies on the subject have been conducted by the IEA in the 2008 and 2013 editions of the World Energy Outlook (WEO) and by the University of Uppsala (Sweden) in 2009 and 2013. The more recent 2013 IEA study was based on the analysis of 1,634 production fields, of which 358 are giant fields and 93% are in decline. The database covers around two-thirds of global oil production. The 2013 Uppsala study was based on 880 oilfields, including about 350 giant fields, covering well over 50% of global production.

**6% average decline rate, with key nuances on field size, type and maturity**

These studies tend to agree on an average decline rate figure of just over 6%, and on the main conclusions which we summarise below:

- ▶ Offshore fields decline 3-6 ppts faster than onshore fields
- ▶ Smaller fields decline substantially faster than large fields
- ▶ World decline rates have been slowly increasing
- ▶ Decline rates accelerate in the final stages of a field's lifecycle, as technology only delays the onset of decline
- ▶ Basin-wide decline rates inevitably catch up with field decline rates

**1: Offshore fields decline 3-6 ppts faster than onshore fields**

**Offshore fields decline 3-6ppts faster than onshore**

Significant differences can be seen between onshore and offshore fields on the one hand, and OPEC and non-OPEC fields on the other hand. There is significant overlap between the two sets of data, as the vast majority of OPEC giant fields are onshore. However, even adjusting for this, the Uppsala study found that non-OPEC onshore declined faster than OPEC onshore (5.1% vs 2.8%), and that non-OPEC offshore declined faster than OPEC offshore (10.3% vs 7.5%).

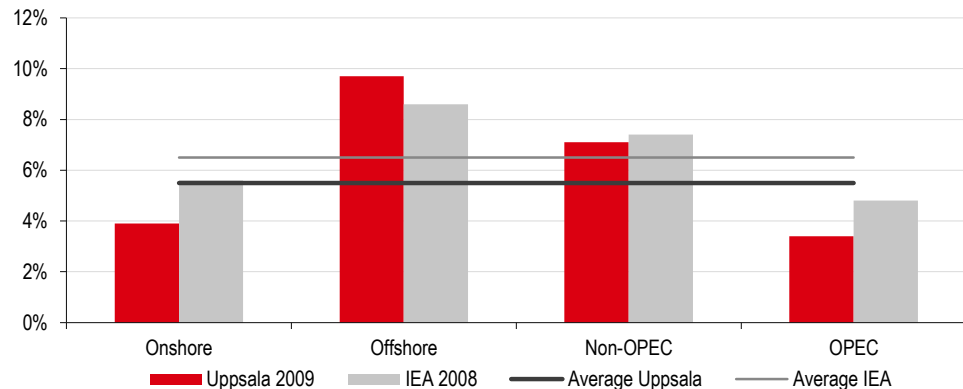
This difference could be partly explained by field size: indeed, many of the world's giants and supergiants are located onshore rather than offshore. As we discuss in the next section, field size has been shown to be inversely correlated with decline rates.

**Average decline rates for post-peak giant fields**

	Uppsala 2013	IEA 2008	CERA 2008
<b>Average decline</b>			
<b>All fields</b>	<b>6.5%</b>	<b>n.a.</b>	<b>6.3%</b>
Onshore	4.9%	n.a.	5.3%
Offshore	9.4%	n.a.	7.5%
Non-OPEC	7.5%	n.a.	6.4%
Non-OPEC onshore	5.7%		
Non-OPEC offshore	10.0%		
OPEC	4.8%	n.a.	5.4%
OPEC onshore	3.8%		
OPEC offshore	7.7%		
<b>Production-weighted decline</b>			
<b>All fields</b>	<b>5.5%</b>	<b>6.5%</b>	<b>5.8%</b>
Onshore	3.9%	5.6%	n.a.
Offshore	9.7%	8.6%	n.a.
Non-OPEC	7.1%	7.4%	n.a.
Non-OPEC onshore	5.1%		
Non-OPEC offshore	10.3%		
OPEC	3.4%	4.8%	n.a.
OPEC onshore	2.8%		
OPEC offshore	7.5%		

Source: "Decline and depletion rates of oil production: a comprehensive investigation", Uppsala University (December 2013), based on Uppsala 2009 study

### Production-weighted decline rates for post-peak giant fields



Source: "Decline and depletion rates of oil production: a comprehensive investigation", Uppsala University (December 2013), based on Uppsala 2009 study

## 2: Smaller fields decline twice as fast as large fields

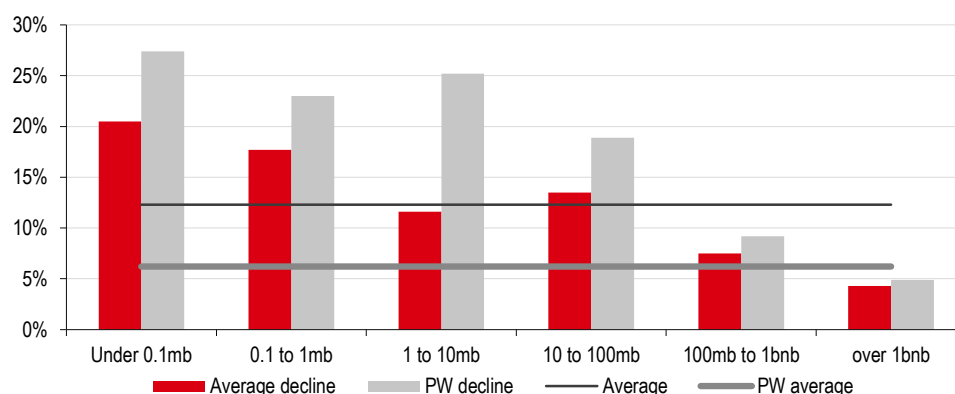
**Small fields decline faster than big fields**

Several studies have shown that decline rates are lower for giant fields than for smaller fields. Beyond geological factors, this feature is the result of several factors:

- ▶ Low declines at giant fields often derive from a deliberate development and production strategy: large fields can be developed through successive phases aimed at maintaining stable plateau production for several years. This is particularly the case for large onshore fields (which can easily be developed in phases), but the idea remains applicable to large offshore fields too.
- ▶ Moreover, in countries highly dependent on hydrocarbon exports, and/or where upstream activity is dominated by national oil companies (NOCs) rather than IOCs (i.e. typically in OPEC countries), large fields are often developed at a slower pace to optimise reservoir conditions throughout their lifecycles and to preserve resources for future generations.

A 2013 study by Uppsala University has shown that decline rates of smaller fields are significantly higher than for larger fields. On average, small fields of less than 10mbbls of recoverable resources decline twice as fast as larger fields of over 10mbbls (whether the decline rates are weighted arithmetically or by production). Unsurprisingly, giant fields of over 1bnboe have by far the lowest decline rates.

### Observed annual decline rates in % for fields of varying sizes



Source: "Decline and depletion rates of oil production: a comprehensive investigation", Uppsala University (December 2013)

While the figures are different, the 2008 IEA study reached similar conclusions, with declines at smaller fields consistently higher than for giants and supergiants regardless of location and field type.

Based on these figures, it seems likely that average decline rates will move closer to the ~10% observed at non-giant fields than the ~6.5% average for giant fields, as global oil production is increasingly driven by smaller oilfields, as we have shown earlier in this report.

### Production-weighted decline rates for different sizes of post-peak fields (IEA data)

	Total	Supergiant	Giant	Other
All fields	5.1%	3.4%	6.5%	10.4%
Onshore	4.3%	3.4%	5.6%	8.8%
Offshore	7.3%	3.4%	8.6%	11.6%
Non-OPEC	7.1%	5.7%	6.9%	10.5%
OPEC	3.1%	2.3%	5.4%	9.1%

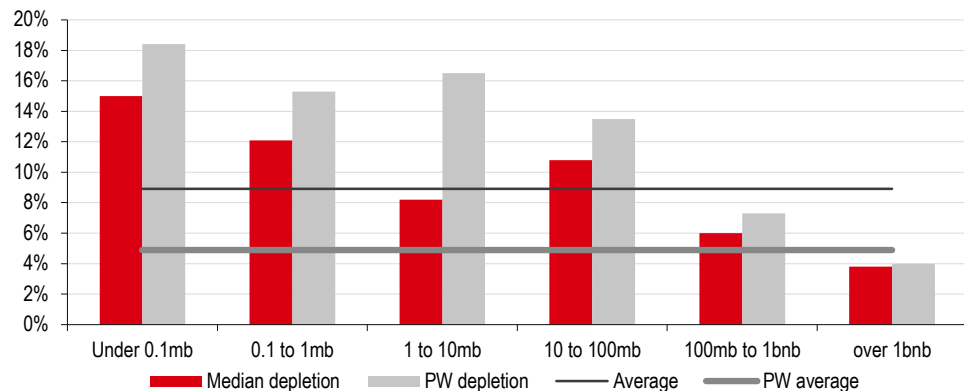
Source: IEA World Energy Outlook 2008. Field sample size: 798.

### Faster depletion of smaller fields explains higher declines

Higher decline rates in smaller fields are strongly correlated with higher depletion rates (defined as annual production as a % of ultimate recoverable resources) at the onset of decline. High depletion rates of 15-20% of URR are frequently observed only in small oilfields, but are very rare in larger fields for reasons previously discussed (optimal reservoir management, resource husbandry etc.).



### Estimated depletion rates of URR at onset of decline, by field size



Source: "Decline and depletion rates of oil production: a comprehensive investigation", Uppsala University (December 2013)

**Big fields have better reservoir optimisation and fewer economic constraints**

Lower depletion at large fields reflects deliberate choices to produce a lower proportion of ultimate recoverable resources at peak levels. Other than politics and resource management, this decision can be driven by i) surface processing capacity constraints and ii) the possibility of easy infill drilling into new areas of the reservoir at later stages, amongst others.

In contrast, smaller fields are designed to bring forward production and NPV, leading to faster depletion of recoverable resources. In many cases, an accelerated production profile is potentially the only way to make a small field economic.

### 3: World decline rates have been slowly increasing

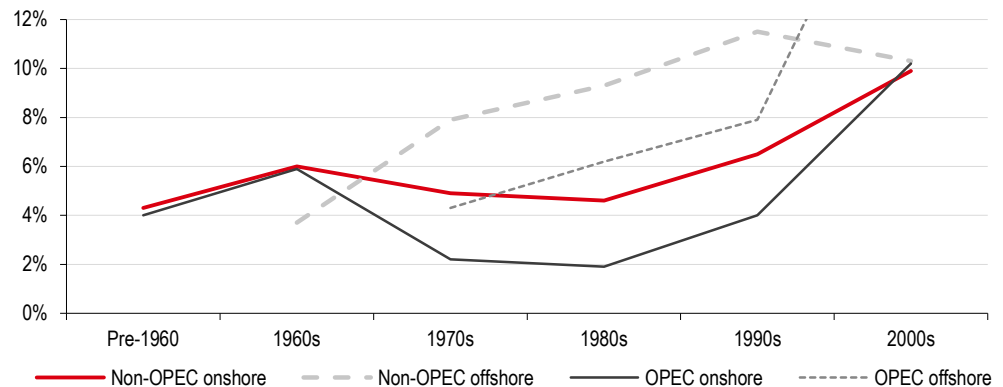
**World decline rates ~5% higher than 30 years ago**

The 2009 Uppsala study has shown that overall decline rates for giant fields – which, let's not forget, are a particularly advantaged sub-section of world oil production – are slowly rising at a rate of ~0.15% per year. This trend reflects several factors including the diminishing size of new giants, deteriorating geology and the impact of technology.

The chart below shows decline rates for 4 different groups of fields, ranked by the decade when the fields entered decline. All groups have shown increasing declines over time, but there are differences between the various groups.

- ▶ The fastest increases in decline rates have been observed within OPEC fields (more so for offshore than onshore), albeit from a low base in the 1970's and 1980's which may reflect OPEC behaviour at the time of the oil crises.
- ▶ Interestingly, decline rates for non-OPEC offshore fields actually *decreased* for fields peaking in the 2000's vs those that peaked a decade earlier. Optimists will argue that this may point to the mitigating impact of technology on decline rates. However, at the time of the 2009 study there was limited data available on fields peaking in the 2000's, so these findings may not turn out to be sufficiently robust.

### Evolution of the decline rate of various field types (grouped by decade of reaching peak production)



Source: "Depletion and Decline Curve Analysis in Crude Oil Production", Uppsala University (May 2009). Declines are weighted by production.

Recovery techniques help delay onset of decline, but not forever

Crucially, the Uppsala study argues that many giant oilfields have managed to extend their plateau phases through technology (secondary and tertiary recovery), *only to experience faster declines once they actually start declining*. In other words, these technologies help to bring production forward by raising the rate of depletion, rather than materially increase recovery rates and the amount of recoverable oil. This would explain why fields that entered decline in the 1990's and 2000's have seen faster declines than older fields that peaked in the 1960-80's, when technology was not applied to the same degree.

Cantarell: a good example of the limits of technology

The sharp output drop at the giant Cantarell field (offshore Mexico) since the onset of decline in 2005 is a good example of what happens once all the "tricks" in the book to extend plateau have been exhausted. In Cantarell's case, secondary and tertiary recovery techniques included nitrogen injection (which was controversial at the time as it is known to cause steeper declines in the long term), infill drilling, horizontal drilling and gas lift.

According to IHS (2007), all of the world's oilfields suitable for secondary recovery methods (water or gas injection) are already applying them. This leaves infill drilling and tertiary recovery or enhanced oil recovery / EOR (e.g. polymer injection, CO<sub>2</sub> injection, etc) as the principal remaining methods used to stem decline rates going forward.

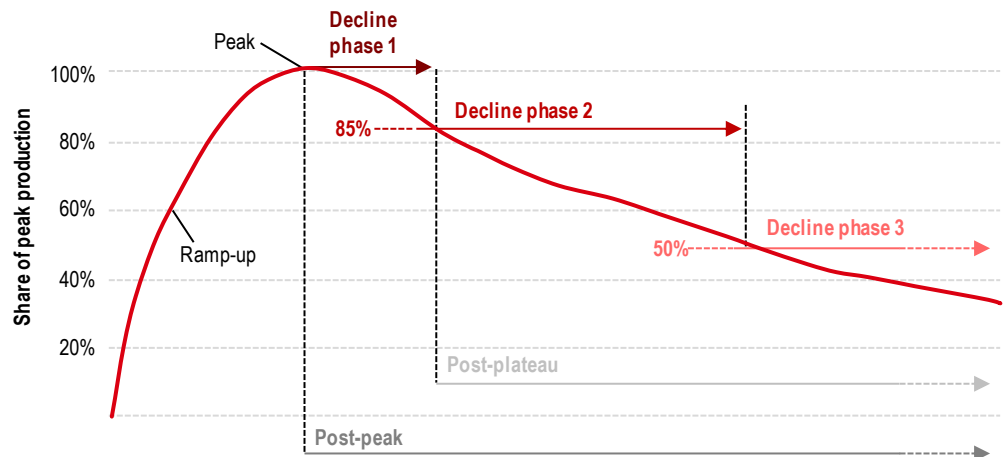
Lastly, an obvious point worth reiterating is that the Uppsala study analysed decline rates for giant fields *already in decline*. Logically, as more giants leave plateau production and enter decline in the next few decades, their *overall* decline rate will rise. The authors estimate that as much as 80% of the world's giants will be in decline by 2030, compared to ~60% in 2005. If the study is right about the impact of technology on recovery rates, then the decline-delaying techniques are only masking what could be significantly higher decline rates in the future.

#### 4: Decline rates accelerate in the final stages of a field's lifecycle, as technology only delays the onset of decline

The IEA (2013 WEO) has argued that using a single decline rate is not a robust basis for long-term supply forecasts, as decline rates evolve through the different stages of a field's decline. In its analysis of decline rates, the agency divides post-peak decline into 3 phases:

- ▶ phase 1, when production remains consistently above 85% of peak level;
- ▶ phase 2, when production is between 50% and 85% of peak;
- ▶ phase 3, when production falls below 50% of peak.

### Indicative illustration of decline phases and concepts (IEA)



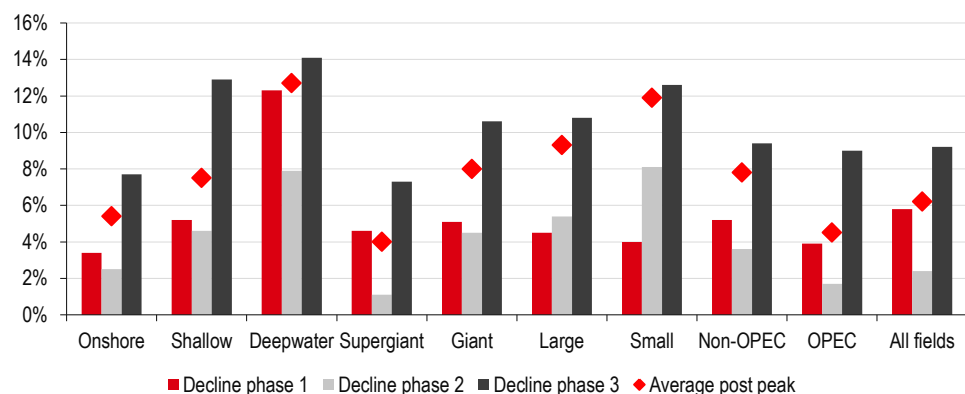
Source: IEA World Energy Outlook 2013

The IEA then calculates a compound average decline rate (CADR) from either the beginning of each phase to the end of the phase or the last year of production.

**Decline rates accelerate in terminal phase**

The results are broken down by the type of conventional field, showing wide variations. As we have shown previously, onshore, OPEC and supergiant fields have the lowest decline rates at 4-5%, while small fields and deepwater fields have the highest declines at 12-13%. The analysis further reveals that **for any type of field, decline rates accelerate in the third phase**, i.e. when fields are in terminal decline.

### Average compound annual decline rate (CADR) to 2012 by decline phase



Source: IEA World Energy Outlook 2013. Average declines are weighted by cumulative production to 2012. Decline rates are calculated as compound-annual decline rates since peak. Supergiants are fields of >5bn bbls recoverable resources, giants are 500-5,000mbbls, large are 100-500mbbls and small are <100mbbls. Deepwater are fields in >1,500m water depth.

This is consistent with the Uppsala University's hypothesis that secondary and tertiary recovery initially limits field decline rates, but does little to stem declines past a certain point.

How do we reconcile this with earlier observations that decline rates often flatten out at the tail end (exhibiting hyperbolic decline curves rather than exponential)? We suspect the answer is that fields that benefit from secondary / tertiary recovery are more likely to see higher decline rates at the end of their lives, after a long period of flatter production aided by technology. On the other hand, fields that have declined naturally will more closely match classic hyperbolic decline models.

Basin declines initially lower than individual field declines...

... but ultimately catch up when new fields get too small

## 5. Basin-wide decline rates increase with maturity

The overall decline rate of a basin typically increases with maturity. While individual field decline rates can flatten out towards the back end of their lives; on the scale of an entire basin the opposite effect is observed, i.e. overall decline rates increase with time.

An oil-producing region is the sum of individual oil fields which reach their individual peak production levels at different points in time. Declining production from post-peak fields has to be replaced by increased production from new fields. As the larger fields in a basin are generally found and developed first, the frequency and average size of new discoveries tends to diminish as hydrocarbon basins get more mature over time.

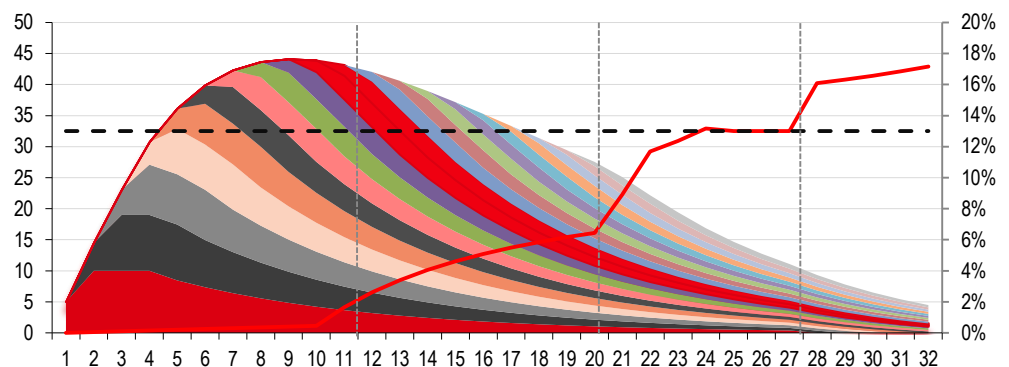
In the early years, new field start-ups (although typically smaller than the basin-opening fields) partly offset natural decline elsewhere. This leads to lower basin-wide overall decline rates compared to individual field decline rates. When no new fields are launched, a basin's overall decline rate catches up with individual field declines. When older fields are shut down at the end of their lives, basin decline rates can eventually exceed field decline rates.

To illustrate this, we have built a theoretical basin-wide model where we assume that (i) one field is brought onstream each year for 20 years; (ii) each field is 10% smaller than the previous field; (iii) fields reach their peak production in year 2, and sustain this level for a further 2 years; (iv) the peak/plateau production level is set at 10% of ultimate recoverable resources (URR); and (v) each field's annual decline or depletion rate is 13%.

This model illustrates how the basin's growth/decline rates evolve through its different lifecycle stages.

- ▶ It starts by exhibiting strong growth in the first 7 years and reaches a plateau around year 9-10, when new fields are ~60% smaller than the initial discoveries and 35-40% of the basin's ultimate recoverable resources have been produced.
- ▶ At the onset of basin decline in year 11, the overall decline rate gradually increases from a range of 3-6% (years 11 to 20), to 9-13% (years 21 to 27) as new fields get increasingly smaller.
- ▶ Ultimately, after around 30 years, the overall decline rate rises to 17-18%+, exceeding individual field decline rates, as older fields stop production when they are no longer economically viable.

### Simple model of a basin's production cycle, vs basin-wide overall decline rate (RHS)



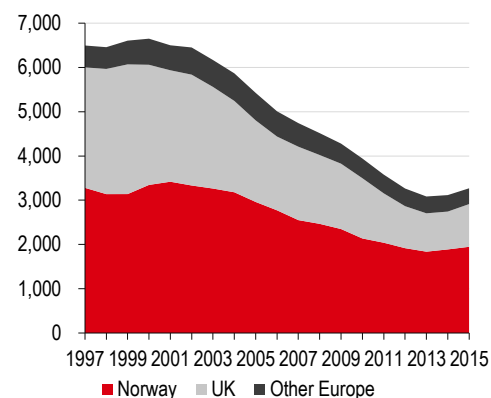
Source: HSBC, based on "The future of oil supply" (December 2013), Richard G. Miller and Steven R. Sorrell

## The example of the North Sea: do theories hold up?

### North Sea data backs up decline rate models

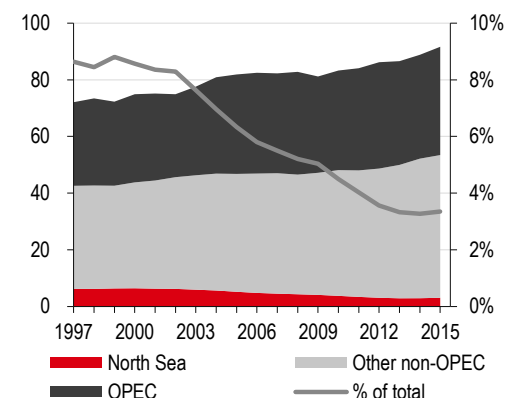
We have gathered annual production data from Norway and the UK, two countries that make up over 90% of total North Sea liquids production. The North Sea is an important example of a classic mature offshore basin which represented 9% of global production 20 years ago, but has fallen to just 3% currently.

North Sea liquids production (kbd)



Source: BP Statistical Review of World Energy 2016

North Sea as % of world production (mbd)

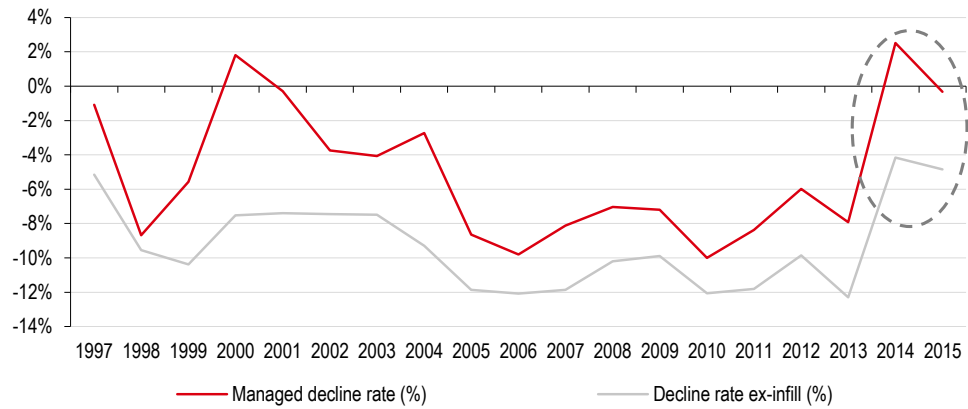


Source: BP Statistical Review of World Energy 2016

From our analysis of several decades' worth of annual production data from the Norwegian Continental Shelf (NCS) and the UK, we make the following observations at the basin level:

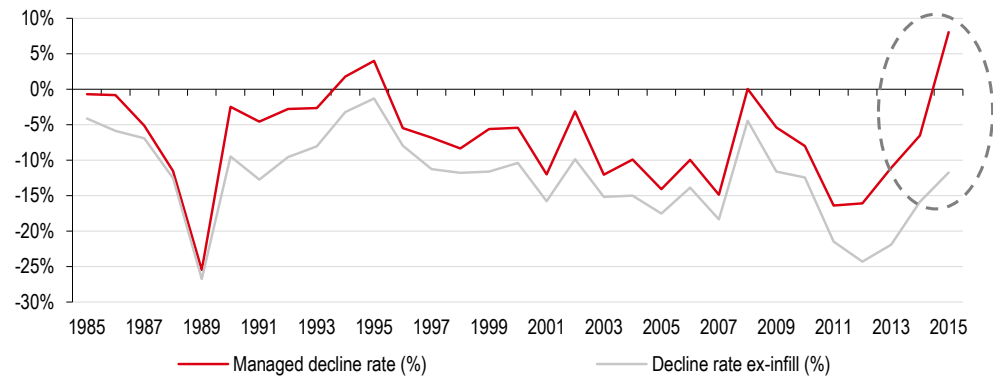
- ▶ We estimate that the *managed* decline rate for liquids since 1997 has averaged ~5% in Norway and 8.3% in the UK. In the last two years, however, managed decline rates appear to have been far smaller or even positive (i.e. increasing base production).
- ▶ The *natural* decline rate has been closer to ~9% and ~14% in Norway and the UK, respectively. The difference between *natural* and *managed* decline rates of 4-6% in the last represents the positive impact of decline-mitigation activities such as infill drilling, IOR/EOR and production efficiency.
- ▶ Our analysis indicates that the impact of such decline-mitigation activities has increased in the last couple of years, likely driven by the increases production efficiency, as we discuss in the next section
- ▶ Decline rates in Norway appear marginally (0.7ppts) higher for crude than for NGLs and condensates, which depend on gas production rates as well as oil. (The UK does not disclose crude oil, condensate and NGL production separately.)

### Managed vs natural decline rates in Norway



Source: HSBC estimates, Norwegian Petroleum Directorate

### Managed vs natural decline rates in the UK

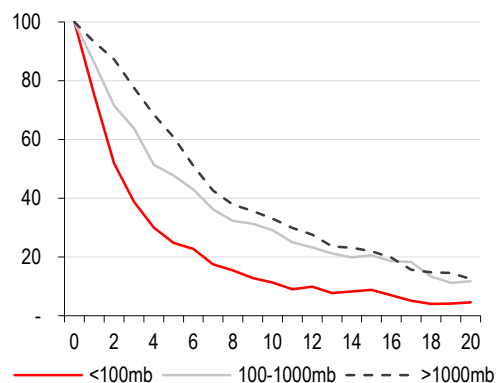


Source: HSBC estimates, UK Oil & Gas Authority

**Small North Sea fields decline faster than big fields at the front end...**

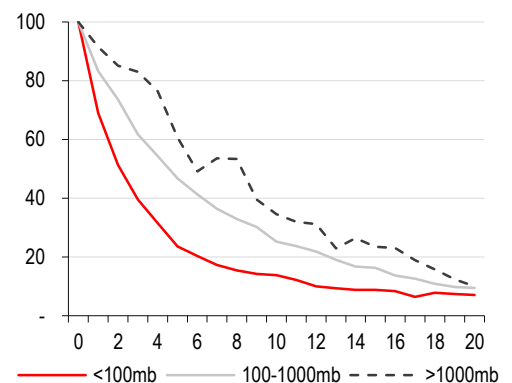
As previously discussed, academic studies have shown that decline rates are generally lower for large fields than smaller fields. Our own analysis of North Sea production data demonstrates that this is indeed the case in Norway and the UK, certainly at the front end of their lives. The charts below show average field production decline curves for fields of various sizes – for simplicity we have shown only three categories, from small (<100mb) to very large (>1bnb), but the conclusions still hold with finer size classifications.

### Production decline curves, ranked by field size (URR) - Norway



Source: HSBC estimates, Norwegian Petroleum Directorate

### Production decline curves, ranked by field size (URR) - UK



Source: HSBC estimates, UK Oil & Gas Authority



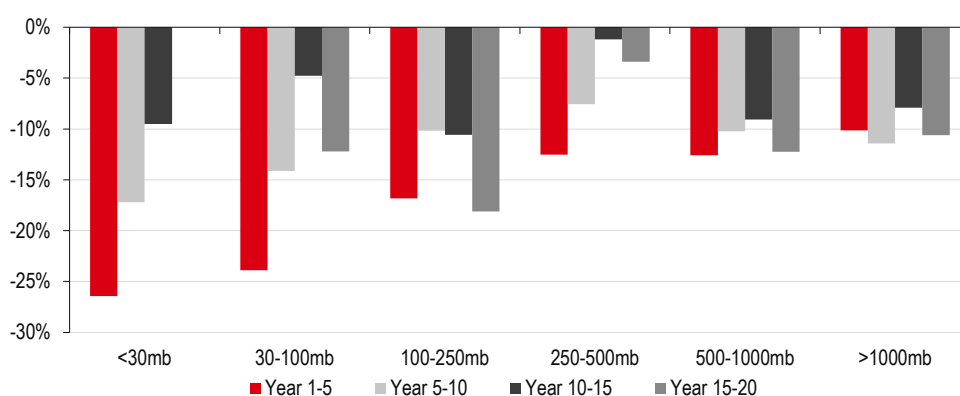
... But big fields have steeper declines at the back end

We have analysed decline rates for different North Sea field sizes as well as for various decline stages. It appears that **decline rates behave differently through a field's lifecycle depending on its size.**

- ▶ **Small and medium-sized fields** in both Norway and the UK tend to follow a classic hyperbolic curve for the first 15 years or so, with very steep declines upfront and lower decline rates at the tail end. This makes sense, as small fields are less likely to have undergone secondary and tertiary recovery.
- ▶ **Large fields** (of over 500mb) in both countries have more stable decline rates through time for the first 15 years of their lives, consistent with the classic exponential curve. However, they show a noticeable acceleration in decline at the end of their lives (after year 15). Technology (secondary and tertiary recovery) appears to have delayed the onset of decline at large fields for the first 15 years, before terminal decline sets in – basically the behaviour predicted by Uppsala University and the IEA 2013 study.

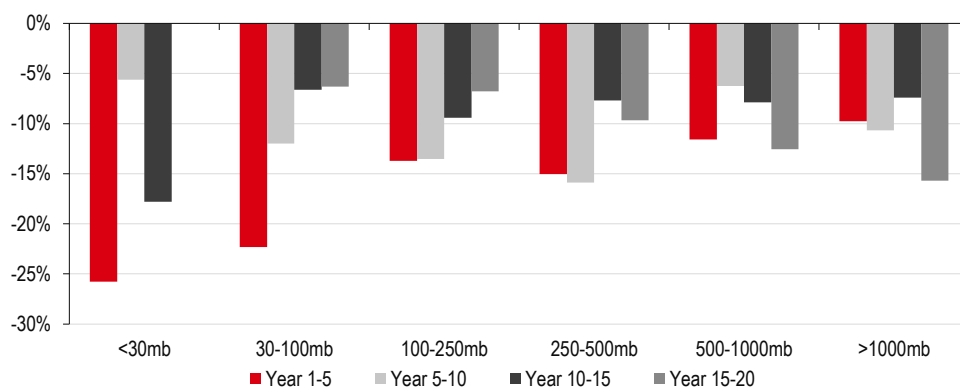
Field size therefore explains much of discrepancy in decline rate behaviour through time: large fields decline slowly thanks to technology, until they enter final depletion-driven decline. On the other hand, small fields don't typically benefit much from improved recovery. As a result, they closely match classic hyperbolic curves, with lower declines at the tail end.

**Decline rates ranked by field size and decline phase in Norway**



Source: HSBC estimates, Norwegian Petroleum Directorate

**Decline rates ranked by field size and decline phase in the UK**

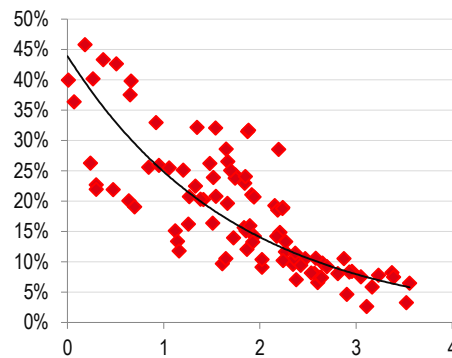


Source: HSBC estimates, UK Oil & Gas Authority

**Big fields' plateau rates set at a lower % of recoverable resources**

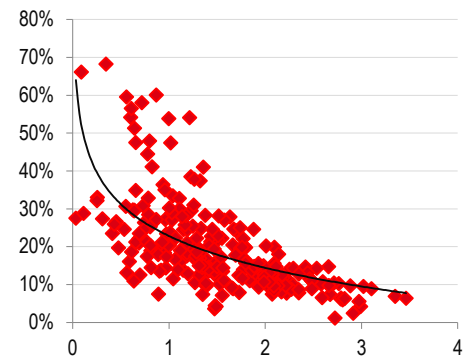
As previously mentioned, big fields decline more slowly than small fields mostly due to long-term reservoir management and the application of secondary and tertiary recovery. The charts below show a clear inverse relationship between depletion-at-peak (i.e. peak production as a proportion of ultimate recoverable resources) and field size on a log scale. In other words, the larger a field is, the lower the plateau rate is compared to total recoverable resources, hence the longer this peak rate can be sustained with little decline.

**Depletion-at-peak rates vs URR (log scale) - Norway**



Source: HSBC estimates, Norwegian Petroleum Directorate

**Depletion-at-peak rates vs URR (log scale) - UK**



Source: HSBC estimates, UK Oil & Gas Authority

**Basin-wide declines set to rise as new fields get smaller**

We have described earlier a stylised basin model which demonstrates that basin-wide decline rates are initially lower than field declines. Basin decline rates then eventually catch up with individual field decline rates, *assuming that new discoveries are smaller than initial basin-opening discoveries*.

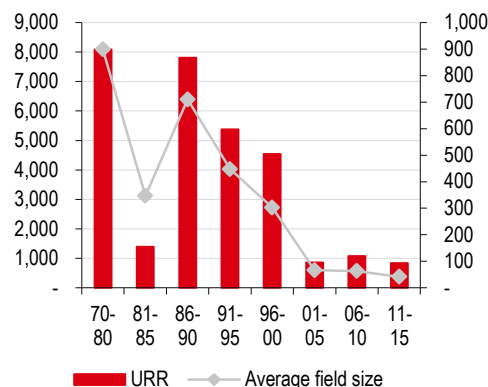
**Basin decline rates much lower than field declines... for now**

Although it is hardly new news, the charts below show that the average size of new field start-ups in the North Sea has indeed declined over time. This points to **basin decline rates getting inexorably closer to individual field decline rates**, unless the trend of discoveries getting smaller can be reversed.

To put this in perspective, the basin-wide managed decline rate is around 5% in Norway compared to individual field declines of ~10% as new field start-ups are partly offsetting decline. In the UK, the basin-wide decline rate is around 8% vs individual field decline rates of ~12%.

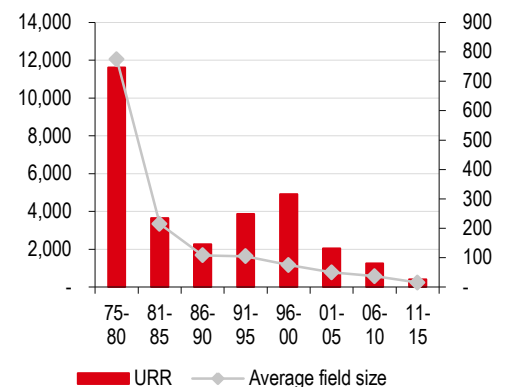
The gap between field and basin decline rates is marginally narrower in the UK than Norway, as new field start-ups in the UK are smaller than in Norway.

**Field size (URR) by start-up period - Norway**



Source: HSBC estimates, Norwegian Petroleum Directorate

**Field size (URR) by start-up period - UK**



Source: HSBC estimates, UK Oil & Gas Authority

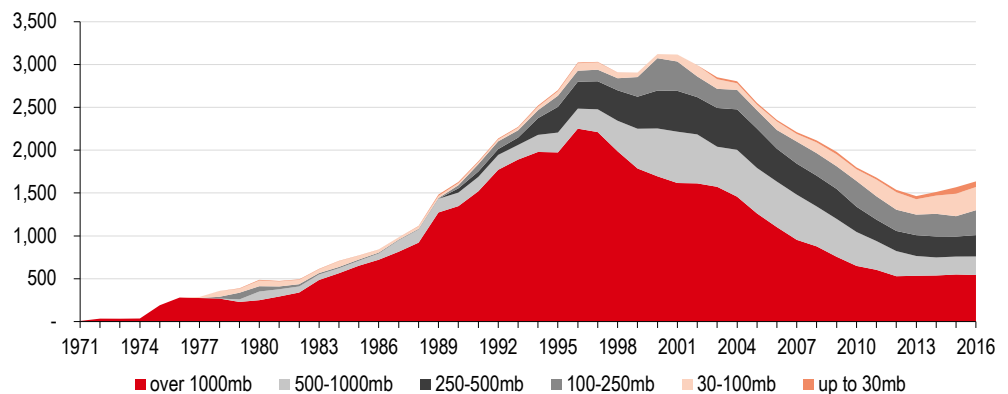
More production comes from small/mid fields vs giants

**North Sea production increasingly coming from small/medium fields**

In this context, it is interesting to note the **growing proportion of North Sea production coming from small and medium fields** and the declining contribution from large and particularly giant fields.

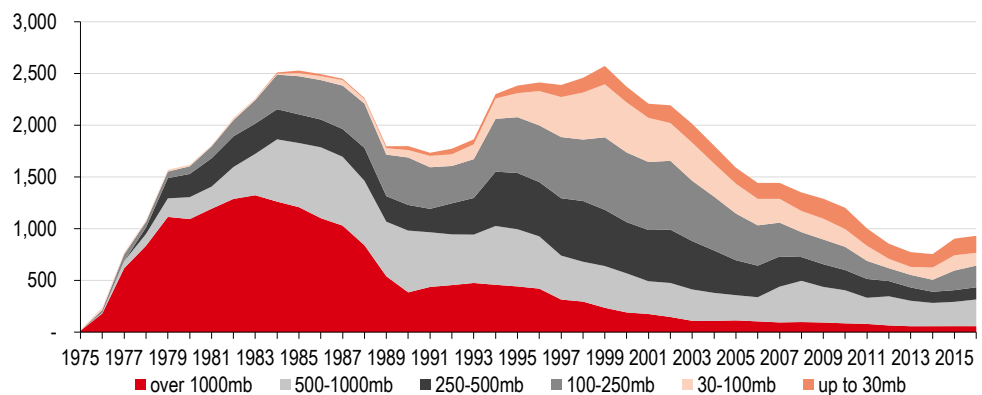
- ▶ In Norway, giant fields of more than 1bnbbbls have fallen to less than 35% of total production, down from nearly three-quarters 20 years ago. Conversely, the contribution of every other category of field – small, medium fields but also “elephants” of >500mb – has risen.
- ▶ The UK has equally been reliant on a few very large fields, but the latter tend to be “elephants” (500mb-1bnb) rather than true giants as in Norway. Following the Norwegian trend, the proportion of giants has collapsed from just under 20% to only 6% of production. However, unlike its northern neighbour, in the UK even medium-sized fields have dropped from 45% to 1/3 of total production – evidence of the UK’s greater maturity. Meanwhile, the contribution from small fields of <100mb has grown from 13% to one-third, far more than in Norway where they currently represent one-fifth of total production.

**Norwegian Continental Shelf (NCS) crude production, ranked by field size (kbd)**



Source: HSBC estimates, Norwegian Petroleum Directorate. Ranked by estimated ultimate recoverable reserves. Excludes condensate and NGL production.

**UK liquids production, ranked by field size (kbd)**



Source: HSBC estimates, UK Oil & Gas Authority. Ranked by estimated ultimate recoverable reserves.

**Rising water cuts indicate field maturity**

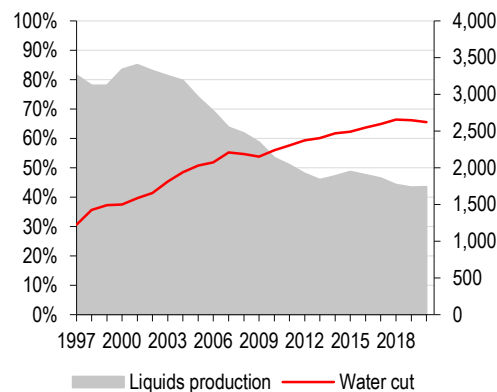
**Rising water cuts are an indication of field maturity**

The UK's greater maturity compared to Norway is also evident in its **higher water cuts**. Water cuts refer to the amount of water produced relative to the volume of total liquids produced. As fields mature, oil production falls and water production rises, notably in fields with water-drive reservoirs (i.e. reservoirs where the oil driven by an active aquifer) or that use water injection as secondary recovery mechanism. At some stage, old wells produce too much water and the cost of handling the water makes it uneconomic to continue producing. At the individual well level, water cuts can rise to 90% or more of liquid volume brought to the surface.

**Water cut 80% in UK, 62% in Norway**

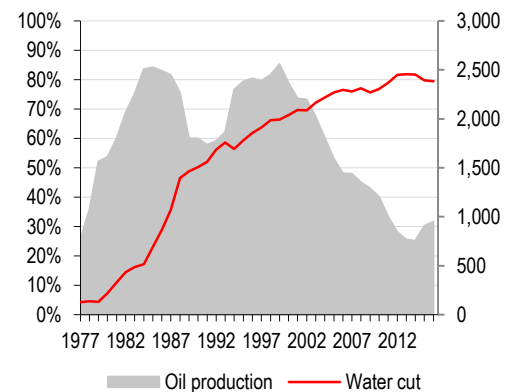
The UK's average water cut has risen from 68% in 2000 to 80% currently, while the average water cut in Norway has increased from 37% to 62% currently.

**Water cut in Norway (last 20 years)**



Source: HSBC estimates, Norwegian Petroleum Directorate

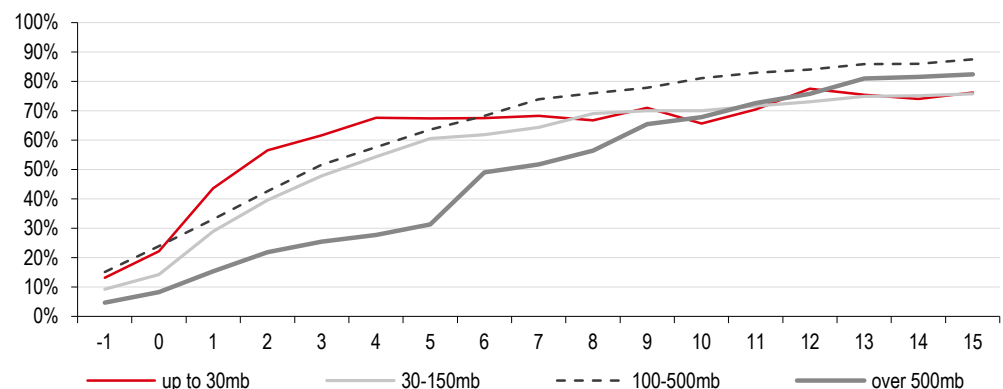
**Water cut in the UK (last 40 years)**



Source: HSBC estimates, UK Oil & Gas Authority

Water cuts tend to rise faster in smaller fields: it takes less than 2 years for small fields to get to a 50% water cut, compared to 6 years for big fields.

**Water cut since peak (year 0) for different field sizes in the UK**



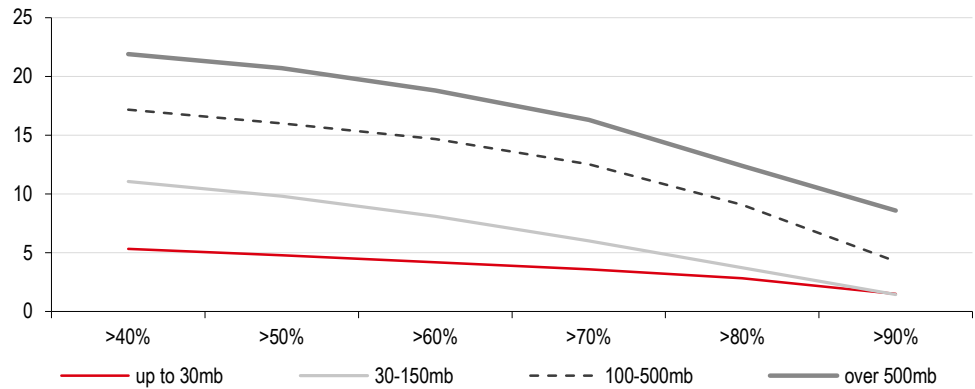
Source: HSBC estimates, UK Oil & Gas Authority

**Big fields can sustain higher water cuts before shut down**

Big fields can typically sustain high water cuts for longer periods than small fields: logically, smaller accumulations are more likely to be shut down early when water cuts become excessively high. In 2015, the average water cut for fields of at least half a billion barrels of reserves was 86% in the UK and 68% in Norway, 6ppts above their respective basin averages. Water cuts are commonly as high as 90%+ for big mature fields (e.g. Forties), while for smaller

fields they usually peak in the mid-to-high 60%'s before the fields get shut down. On average, small UK offshore fields can expect to produce just 1.5 years once they get past a 90% water cut, while large fields can expect to produce another 9 years.

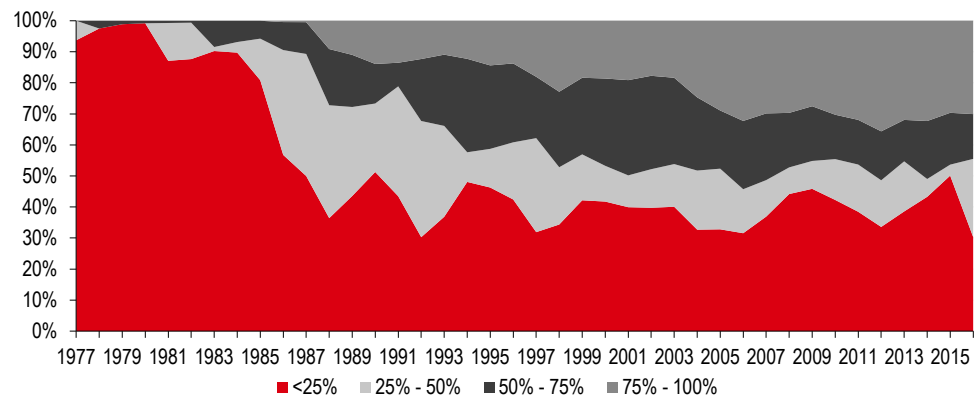
#### Post-peak life expectancy for UK fields past % water cut levels, ranked by field size



Source: HSBC estimates, UK Oil & Gas Authority

Around 30% of all UK production has a water cut of over 75%, up from 19% in 2000. While it is yet another proof of the basin's increasing maturity, it also indicates a rising proportion of fields are at risk of being shut down within the next few years.

#### Fields with high water cuts contribute a growing proportion of UK production



Source: HSBC estimates, UK Oil & Gas Authority

## Case study: China's Daqing

Although China is seen mostly as a major oil consumer, the country is also an important global oil producer, the sixth largest in the world. The three NOCs (PetroChina, Sinopec and CNOOC) contributed a collective 5% of global oil supply in 2015. Pressures created by low oil prices and reservoir maturity have contributed to 140kbd lower y/y production levels year-to-date in 2016 (January-July), although more recent datapoints show y/y declines of more than 300kbd (-7-8% y/y).

### Daqing: onshore giant in decline

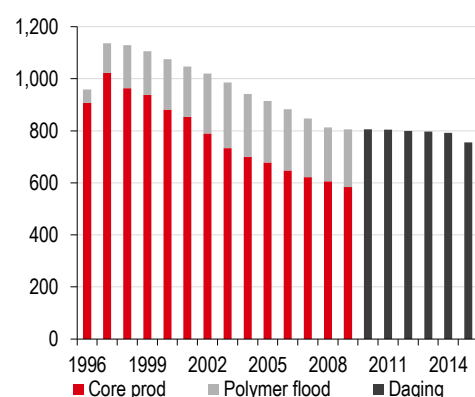
As we discussed earlier in this report, the world's large reservoirs, both within OPEC and outside OPEC are relatively mature. PetroChina's Daqing field is a good case in point: this oil region is PetroChina's largest oil and gas producing property, located in the Songliao basin. The producing areas cover approximately one million acres.

Since its start more than 50 years ago, Daqing peaked near 1.1mbd in 1997 and is currently producing just under 756kbd. This production has held up for decades, to the surprise of many analysts and oilmen. This extension of peak recovery rates was achieved largely through the use of Enhanced Oil Recovery (EOR) techniques including basic water injection, and more recently newer EOR techniques, namely Alkaline-Surfactant-Polymer (ASP) flooding. CNPC/PetroChina continue to apply EOR recovery to the liquid production. A new flooding system consisting of alkaline, surfactant, polymer, and natural gas is significantly increasing recovery rates. ASP-foam flooding recoveries can be c.10% higher than simple ASP flooding and 30% higher than by water flooding.

From 2001 to 2009, Daqing's water cut increased from 87.4% to 91.5%. Interestingly, the operator stopped disclosing the field's overall water cut in 2010.

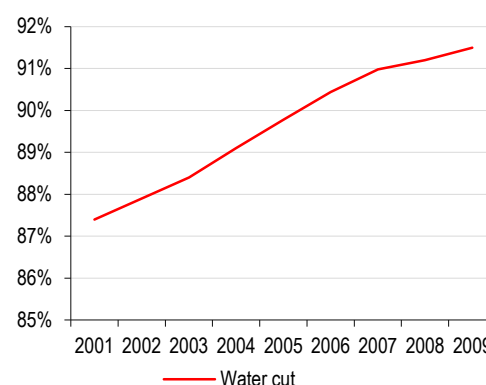
China's other two Majors, Sinopec and CNOOC, also operate in more mature basins and have significant well declines in core production areas of the order of 4-8% p.a. each (see charts overleaf).

Daqing field production (kbd)



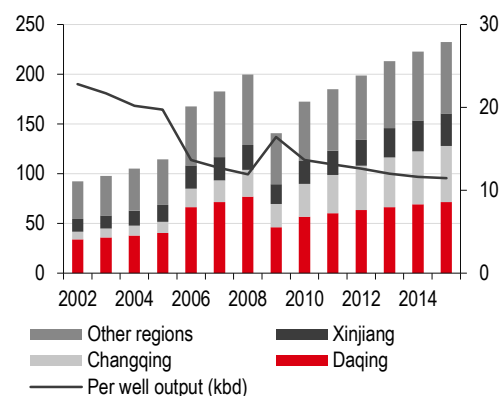
Source: CNPC, PetroChina

Daqing water cut (%)



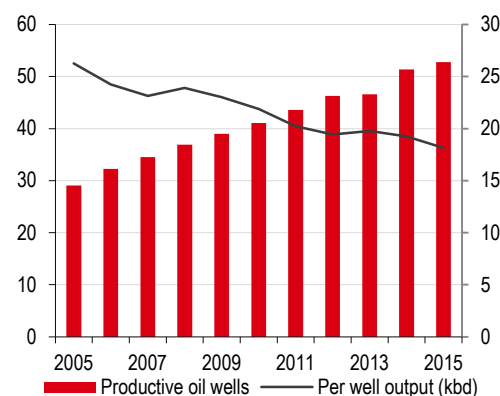
Source: CNPC, PetroChina

**PetroChina productive oil wells ('000) and per-well output (RHS)**



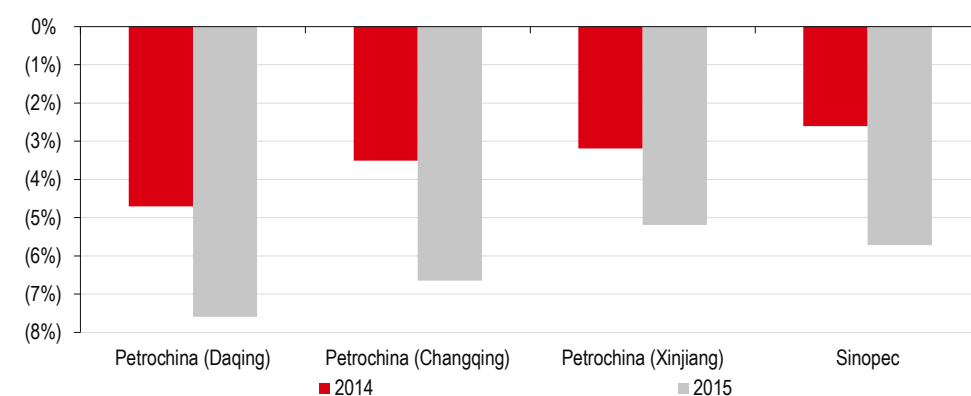
Source: Company reports

**Sinopec production oil wells ('000) and per-well output (RHS)**



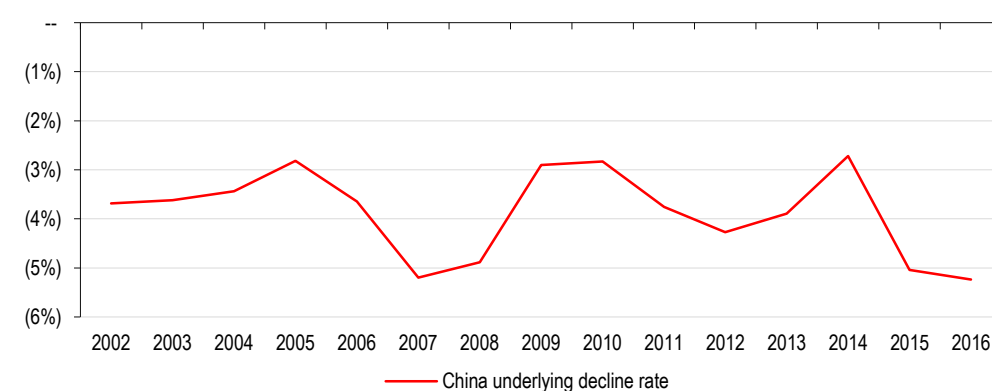
Source: Company reports

**Annual change in per-well output for PetroChina and Sinopec (y/y)**



Source: Company reports

**China underlying annual decline rate (%)**



Source: HSBC estimates, Wood Mackenzie

# Production efficiency and decline

- ▶ Improvements in production and drilling efficiency in recent years have masked underlying decline rates
- ▶ For example, UK production efficiency rose from 60% in 2012 to 71% last year
- ▶ Production efficiency can't keep improving forever – some countries / assets have already reached their maximum potential

North Sea production has surprised to the upside due to production efficiency

## Why has production surprised to the upside?

In many mature basins such as the North Sea, crude production has surprised to the upside in the last 18 months, despite sharp reductions in capital spending and drilling activity. For instance, UK liquids production rose 13% y/y in 2015 (the first increase in 16 years), while Norway liquids production rose by 3% y/y (the second consecutive increase after 12 years of decline). Several factors explain the production increases seen last year:

- ▶ **New field start-ups** in the UK and Norway played a major part. In the UK there were 8 new start-ups in 2015, adding to the ramp-ups from two large projects that started in late 2014. In Norway, there were 4 new field start-ups respectively in 2015 and 2014.
- ▶ In the UK, a number of fields which were previously shut in for various reasons came back onstream last year. In volume terms, the contribution from field restarts was roughly equal to the new field start-ups and ramp-ups. However, field start-ups and restarts together do not fully explain the North Sea's production turnaround.
- ▶ **Increased production efficiency** meant that existing assets delivered higher production than expected, and helped to reduce decline rates. UK trade association Oil & Gas UK estimates that production declines from existing fields slowed from 12% to just 4% last year, as production efficiency rose to over 70% from a low of 60% in 2012.

## Digging into production efficiency

"Production efficiency" measures actual output vs capacity

It is hardly new news that – until very recently – North Sea production has been in decline for years, having peaked in 1999-2000. Despite last year's rebound, the combined output of the UK and Norway is still roughly 50% below its peak and has shrunk at a 4.6% average annual rate.

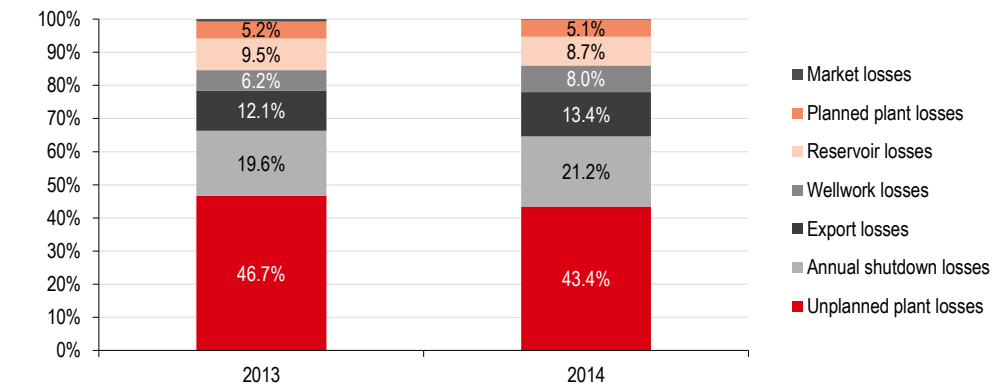
A lack of new big field start-ups is only partly to blame for this: indeed, a large part of the North Sea's decline over the last 10 years is explained by worsening production efficiency. Production efficiency (often abbreviated "PE" in the industry) is defined as actual annual production divided by the maximum production potential of a given field or group of fields.



**Unplanned shutdowns = 50% of production losses**

Production efficiency reflects planned losses (e.g. for maintenance purposes) as well as unplanned production losses. 2014 data from the UK Oil & Gas Authority (OGA, previously called DECC) has shown that unplanned shutdowns makes up nearly 50% of the overall losses on the UKCS, with planned annual shutdowns representing around 25%, and the rest due to well work, reservoir and export losses.

**Breakdown of average UKCS production losses**

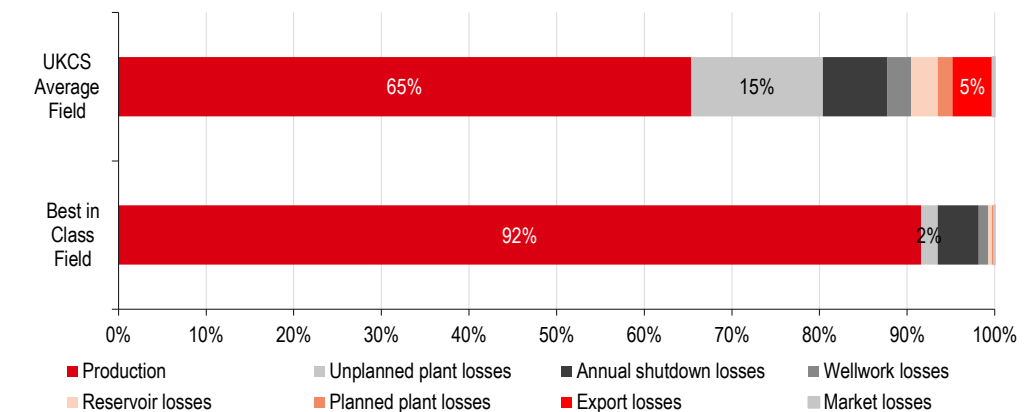


Source: UK Oil & Gas Authority

**Operators have strong influence over production efficiency**

Data has also shown that there is a large and widening gap between best-in-class and worst-in-class operators in the UK. While the average UKCS field achieved a production efficiency of only 65% in 2014 (implying 35% downtime), best-in-class fields achieved 92% efficiency or 8% downtime.

**UKCS production efficiency – average vs best-in-class field**



Source: UK Oil & Gas Authority

- The biggest difference between leading and lagging fields is the magnitude of **unplanned plant losses**: unplanned plant losses are close to 8 times higher at average fields compared to best-in-class fields. The quality of operator practises, rather than field/platform age, is a strong predictor of unplanned losses. In other words, this means that improving plant uptime is largely in operator's hands.
- The second biggest delta between leading and lagging fields comes from **export losses**. This factor is somewhat less under operators' control, as export availability depends on a platform's position on the hub network: indirect hubs that rely on third-party hubs to export oil & gas are likely to suffer more than direct hubs. However, this inter-dependence also means that uptime improvements at direct hubs can have a positive knock-on impact on indirect hubs' production efficiency.

### UK production efficiency bottomed at 60% in 2012

Data from OGA has revealed that production efficiency on the UKCS was on a steady downward trend from 2004 to 2012, falling from 81% and bottoming out at 60% (-2.6% per annum). In response to this trend, the industry and UK government formed the Production Efficiency Task Force (PETF) in June 2013 to address falling production efficiency. The PETF set an ambitious production efficiency target of 80% for 2016, rising to 85% from 2017 onwards. The focus group is taking a three-pronged approach:

1. **Improved business processes:** challenging and minimising planned downtime, continually improving reliability by learning from failures.
2. **Standardisation** in areas such as subsea, valves, well plugging & abandonment.
3. **Cooperation and sharing of best practices.** This starts with like-for-like accurate reporting of production efficiency across operators to enable data analysis. The task force set up a web portal allowing UK asset operators to share successful stories on efficiency improvements.

### “Wrench time” could rise from 30-40% now to 75-80%

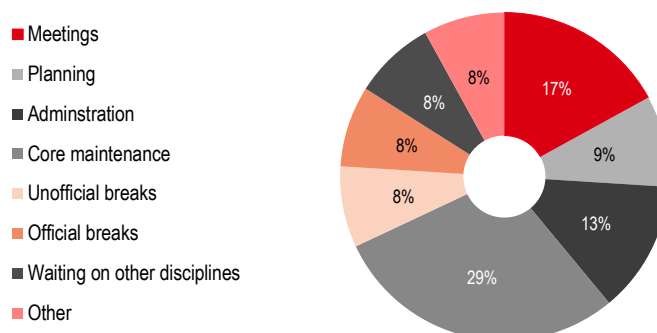
### <40% of offshore workers’ spent on core maintenance

One of the four key issues currently being investigated by the PETF is “**wrench time**”, the amount of time offshore spent on productive activities, as opposed to non-value adding activities. Data has shown that as little as 29-38% of offshore operators’ time out of a 12-hour shift is actually spent on core maintenance, or under 4 hours a day. Meeting, planning, administration and waiting on other disciplines makes up 40-45% of working time, and various breaks the remaining 20-25%.

### Some companies better than others at production efficiency

There are significant variances between operators, which points to significant upside as the laggards catch up with more efficient operators. Industry body Oil & Gas UK estimates that best practise is six hours of productive time, and in some cases, as many as nine hours. For instance, BP recently said that it currently gets around 4.5 hours of effective time in an 8-hour shift in its Norwegian operations. This compares to 11 hours at Norwegian independent Det Norske. The potential for productivity improvements was likely one of the main drivers behind the BP-Det Norske tie-up combining the two companies’ Norwegian operations announced in June. Some operators have already managed to significantly improve wrench time, for instance Nexen with a 30% increase in productivity in 2015.

### Typical breakdown of working day (12-hour shift)



Source: UK Oil & Gas Authority, based on Hitachi Consulting study

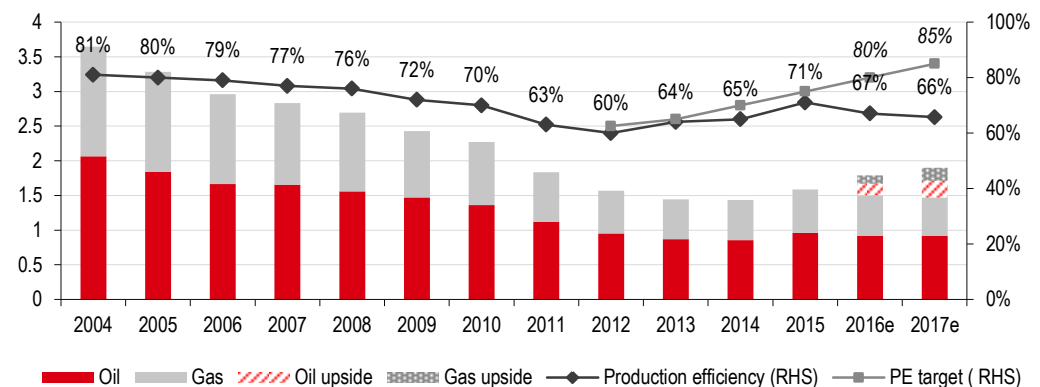
There are many aspects of daily offshore operations where simple, incremental changes can positively affect “wrench time”. For instance, detailed planning and preparation before a turnaround can ensure that all the necessary materials, equipment and manpower are in place. Improved systems & procedures, staff training and knowledge sharing can also help. Staff capabilities are particularly crucial in an offshore environment where shift patterns means that a single position could be covered by up to six different employees in a month. In response to low oil prices, many UK operators have already moved to a “three weeks on, three weeks off” pattern, instead of the traditional “two on, three off”.

#### Production efficiency rose sharply last year, but more to go

All these initiatives have started to bear fruit: UKCS production efficiency rose to 64-65% in 2013-14 after 8 consecutive years of deterioration, and jumped to over 70% last year. Although this scale of the improvement is impressive, 2015 production efficiency still came in below the task force’s target of 75% and is only back to 2009-10 productivity levels. In short, UK offshore productivity is around halfway back to where it used to be.

UK production efficiency has risen to >70%, more to go

#### UKCS Oil & gas production efficiency



Source: UK Oil & Gas Authority, HSBC estimates

#### Up to 200kbd UK production upside from efficiency improvements

The OGA’s conservative UKCS production forecasts are based on the assumption that production efficiency goes *backwards* in 2016-17e to 67% and 66%, down from ~71% in 2015. These assumptions are a long way below PETF’s targets of reaching 80-85% efficiency over the period, and strike us as overly pessimistic. As operating procedures become embedded in day-to-day practises, we see no reason why offshore productivity should deteriorate in 2016-17.

Assuming a similar rate of improvement in 2016-17e to that seen over the last 3 years (+3.7 ppts per year), we estimate potential upside in UK oil output of 90kbd in 2016 and 140kbd in 2017 vs the OGA’s conservative forecasts, or 110kbd vs the IEA’s more realistic 2017e production forecast (~11% of UK production). Achieving the PETF’s stretch targets would offer 170-240kbd upside vs the OGA’s forecasts, or 80-210kbd upside vs the IEA’s.

#### Norway appears to be ahead of the UK on production efficiency

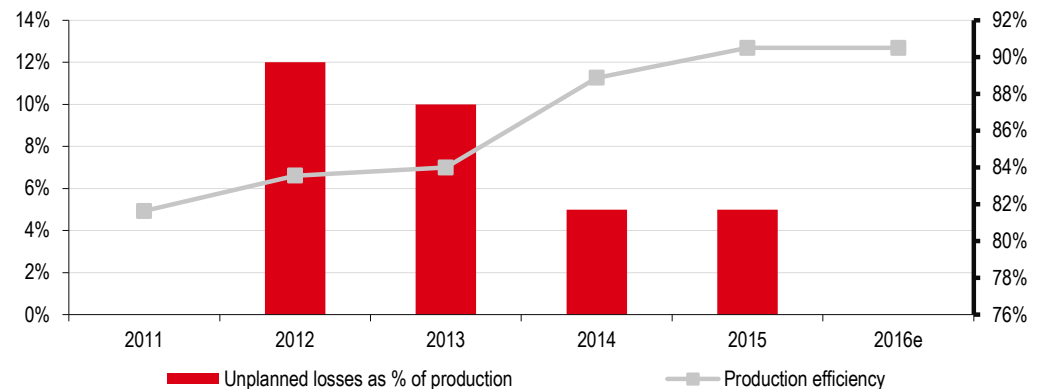
In its annual reviews of the Norwegian Continental Shelf, the Norwegian Petroleum Directorate (NPD) cites higher regularity as the most important reason behind the production rise on the NCS in 2014 and 2015, ahead of new field start-ups & ramp-ups and drilling efficiency.

In the last two years, Statoil has managed to halve unplanned losses compared to 2013 levels down from 10% to just 5%. Production efficiency has increased by 6.5 ppts since 2013 to above 90%, and stands at 92% or more at 15 fields.

Further improvements could add up to 200kbd to UK oil output in 2017

Norway ahead of UK; less room for improvement

## Statoil – Improvements in regularity and production efficiency



Source: Statoil February 2016 presentation

Statoil represents c.70% of Norway's liquids production, including the Petoro state share. As such, trends seen at Statoil are probably fairly representative of the NCS as a whole, and we can probably infer that Norway's production efficiency is ahead of the UK. However, Norway's head-start on the PE front means that there is logically less scope to further improve performance than on the UK side of the border. Indeed, Statoil expects to maintain production efficiency at similar or slightly higher levels in 2016 compared to last year, though this will be offset by higher planned turnaround activity.

## Drilling productivity has stemmed decline rates

## Drilling efficiency is key

Achieving better drilling efficiency is another area that offers significant upside potential for operators, since drilling represents a large share of upstream capital expenditures at around 40-50% of project costs. Alongside production efficiency, greater drilling productivity has played a key role behind the improvement in decline rates in mature regions such as the North Sea.

## Drilling spending -50% in Norway since peak, but activity is up

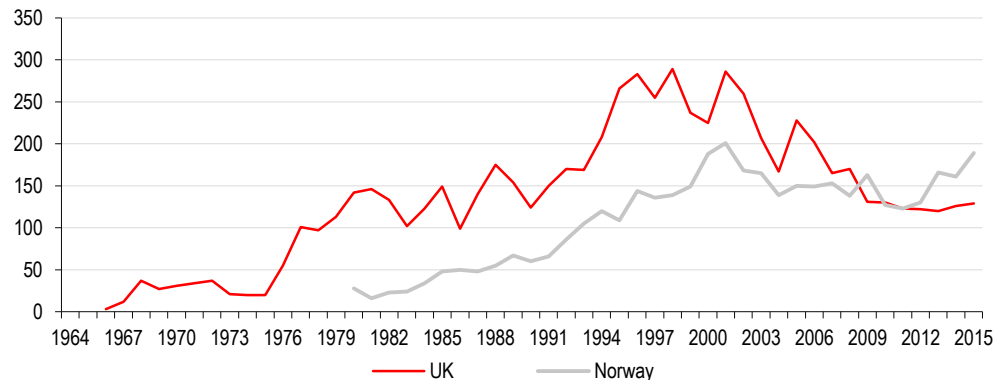
Oil market observers are well aware that drilling spending worldwide has declined materially since the 2013-14 peak. For instance, spending on development drilling offshore Norway is expected to fall by 45% in USD terms between 2013 and 2016e (-21% in NOK), according to the Norwegian Petroleum Directorate. In the UK, development spending in USD terms is set to fall by 50% between 2014 and 2016e (-40% in GBP).

But looking at spending alone would be misleading: drilling activity levels in the North Sea have actually *increased* over the period. The number of development wells rose in the UK from 120 in 2013 to 129 last year, while Norway saw 189 developments wells drilled last year (up from 166 in 2013), the second-highest number on record.

## Higher drilling activity offsets natural decline

It is clear that higher development drilling activity has been a major factor behind the North Sea's surprisingly resilient production performance.

### Development wells drilled per year, UK vs Norway



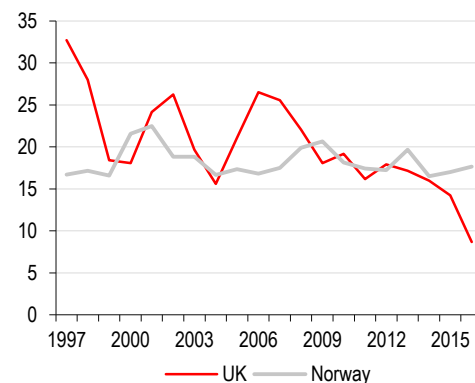
Source: Norwegian Petroleum Directorate, Oil & Gas Authority

**Fewer rigs at work, but each rig can drill up to 45% more wells p.a.**

The ramp-up in drilling activity in the North Sea was achieved despite a reduction in the number of active drilling rigs. The UK rig count fell from 16-17 rigs in 2013 to 14 last year and has dropped further to fewer than 9 rigs so far this year. The Norway rig count followed a similar trend to the UK as it fell from 20 in 2013 to 17 in 2015, but unlike the UK appears to have stabilised this year.

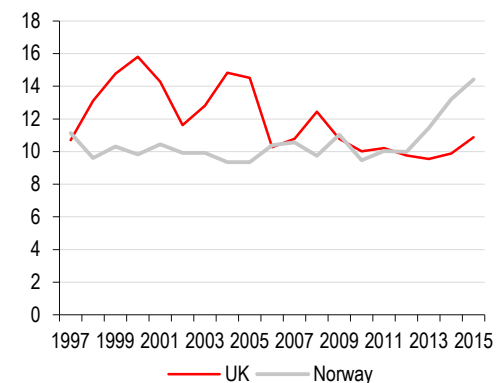
Taken together, the data shows that each rig drilled 45% more wells in Norway and 11% in the UK last year vs 2012. This supports Statoil's assertion that it is drilling wells c.30% faster than in the past, which is equivalent to drilling c.43% more wells.

### Rig count, UK vs Norway



Source: Baker Hughes

### Total wells drilled per rig, UK vs Norway



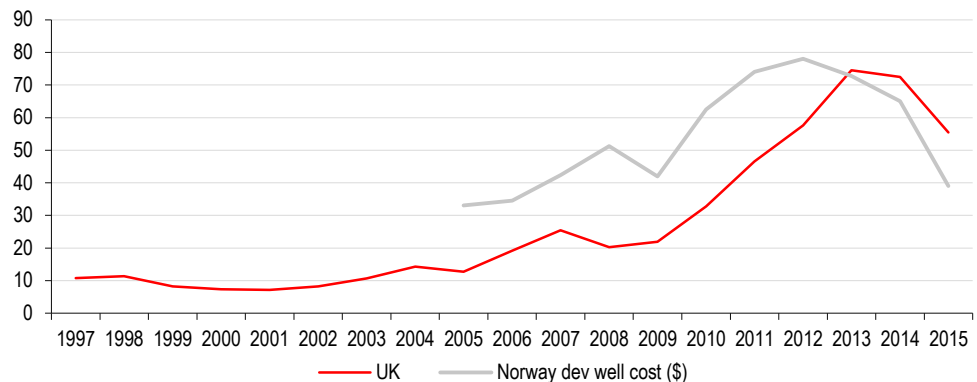
Source: Norwegian Petroleum Directorate, Oil & Gas Authority, Baker Hughes, HSBC estimates

**Development wells 50% cheaper in Norway vs peak**

As a result, unit development well costs have fallen by 50% in dollar terms since their 2012 peak in Norway (-31% in NOK terms). If we assume constant rig productivity – i.e. each rig drills takes 25 days to drill, development well costs would fall by a further 12-15% this year, partly thanks to cost deflation.

The UK North Sea's performance has been a little less impressive, with a 26% fall from peak 2013 unit well costs in dollar terms (-24% in GBP). Well costs in Norway were historically significantly higher than in the UK for various reasons, mainly to do with expensive labour, high specifications and strict environmental standards and regulations. But over the last couple of years, improved drilling efficiency coupled with the Norwegian krone depreciation means that it was 30% cheaper to drill a well in Norway than in UK last year. This reversal of fortune – among other factors – helps to explain why Norway has overtaken the UK on drilling activity in the last 3 years.

### Development well costs, UK vs Norway (USDm per well)



Source: Norwegian Petroleum Directorate, Oil & Gas Authority, Baker Hughes, HSBC estimates

Lessons from North Sea can be applied to many offshore regions

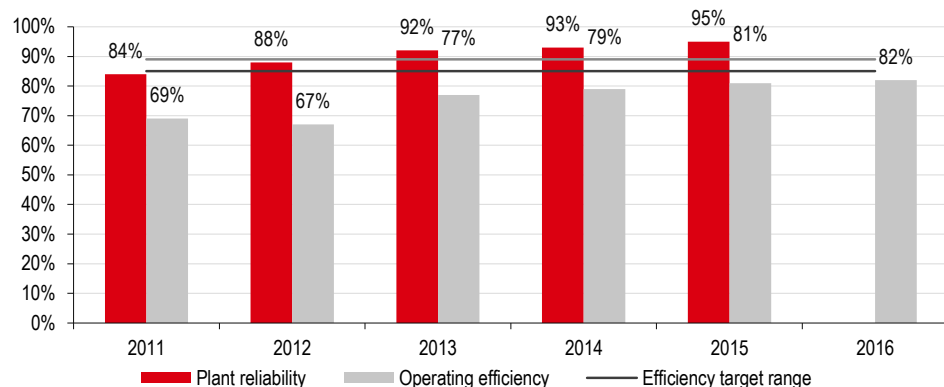
### This isn't this just a North Sea example – the rest of the world has also improved

We are conscious that we have studied only two non-OPEC producing countries in the above discussion – UK and Norway. Nonetheless, we think that trends such as increased production efficiency, drilling productivity etc, apply to many other offshore basins around the world – not least because global operators (i.e. the Majors) have strived to spread best practises throughout their upstream portfolio. There is plenty of anecdotal evidence from oil majors under our coverage pointing to improved operational performance across the board.

For instance, BP has achieved significant improvements in production efficiency and reliability across its entire portfolio:

- ▶ Planned outages have reduced by 50% since 2011 partly thanks to improved execution on turnarounds (i.e. maintenance shutdowns), while plant reliability has increased from 84% to 95%.
- ▶ BP's overall operational efficiency has risen from 69% in 2011 to 82% in 2016. The North Sea, which represents 7-8% of BP's total production (ex-Rosneft), has seen an improvement from 72% to 82% in the past two years. Crucially, the small weight of North Sea production in BP's portfolio means that there have been significant efficiency gains elsewhere – in other words, this is categorically not just a North Sea trend.

### BP operating efficiency and plant reliability (%)



Source: Company data (June 2016 Baku field trip presentation)

BP targets an efficiency rate in the mid to high-80's over the next few years, and assumes a mid-80's efficiency rate in its 3-5% decline rate guidance.

If we believe BP's guidance, there may well be a further 3-6 pts upside in its portfolio operational efficiency over the next several years. This would substantially mitigate natural decline, as every 1 ppt improvement in production efficiency is broadly equivalent to a 1 ppt reduction in its decline rate. However, a 3-6 ppt improvement needs to be put into the context of a 13 pts increase over the last 5 years.

**Don't be fooled by high individual field efficiency numbers**

Moreover, once the company hits its high-80's efficiency target there will simply not be much further upside, if at all, as 90-92% production efficiency appears to be a natural limit. There is anecdotal evidence of certain (best-in-class) fields reaching 97-99% production efficiency levels. However these levels are reached outside planned maintenance periods and do not leave much room for any unplanned outages. Across an entire company's portfolio and over a full maintenance cycle, we believe the maximum sustainable production efficiency level is probably 90-92%.

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**Natural limit to production efficiency across a whole portfolio probably 90-92%**

## Appendix: What oil companies are saying on decline

Oil majors have strived to maintain their average portfolio decline rates unchanged in a 2-5% range despite lower investment, notably thanks to greater production efficiency and growth from long-life assets and unconventional. However, much of this growth is in gas/LNG, not oil. In contrast, oil service companies have been notably more vocal about the supply challenges from rising decline rates. It would be easy to accuse service companies of “talking their own book”, but we believe the latter are probably closer to the truth.

### Company comments on decline – Spot the difference

#### What the producers are saying

**BP:** “By enhancing oil recovery and increasing the amount of drilling we do, we have reduced planned deferrals, increased plant reliability, and established a four-year track record of base decline of less than 3%. For planning purposes, we expect our future base decline to be in the 3% to 5% range. [...] we’re going to do everything that we can to keep it to the lower end of the 3% to 5% range” – *July 2016, 2Q16 conference call*

**Shell:** “Each particular strategic theme has a different, if you like, challenge in decline rates, with the highest challenge being in the conventional and gas, then deepwater. [...] So the total decline rate has been around 5%. It’s moved to a 4%, and it’s probably heading lower.” – *June 2016 Capital Markets Day*

**Total:** “The average decline in this oil industry is around 5%. By the way, this decline will not be lower if we continue to invest less in the oil industry; it will accelerate the decline. [...] We have a decline of around 3.5%” – *4Q15 conference call*

“We are surprised to see actually on our figures a lower-than-expected decline rate at the moment, because we are more in the range of 3% than 3% to 4% at the moment. But going forward, less works on brownfield but more long plateau project[s]; I think we will be able to maintain the 3% decline rate.” – *July 2016, 2Q15 conference call*

**ENI:** “Our strategy is keeping 5% our decline. So we are fighting all these numbers through our continual reservoir modelling and petroleum engineering. Basically since the objective was also to reduce costs [...], we directed most of our activity in rigless instead of large and heavy work” – *3Q15 conference call*

**Statoil:** “[Decline in Norway] has been around 5%, fairly much the same rate as the international. [...] We have offset decline and achieved a production growth due to strong operational performance.” – *February 2016 Capital Markets Day*

**Chevron:** “We are going to see somewhat higher decline rates. Right now we’ve been able to maintain our base fully invested at less than 2% including our shale. As we move forward we’d expect to see that probably increase to more like less than 4% not including the shale. But when we add the shale and tight back in we should be in that 1% to 2% range. As projects like Gorgon and Wheatstone come into the base, right now we treat those as major capital projects but as they start production, they add decades-long stable production to us and actually help us with that equation. Shale and tight growth like in the Permian tends to increase your decline rates because obviously the nature of those types of wells have individually high declines. So the balance is we should stay pretty stable to where we are but we will see the uninvested decline rate increase.” – *March 2016 Strategy Update*

**Exxon:** “We have an underlying decline, as we include in our 10-K, of about 3%. On top of that we had major project activity.” – *February 2016, 4Q15 conference call*

“Our decline rate really hasn’t changed over the last year since we had guidance last time. It does imply some optimisation that goes along with our base, that I think we are doing actually a better job of today with a little more focus on it. But we have a mix of long-plateau assets and some of the unconventional. And when you kind of combine that portfolio, I think that’s still an apt description of where we are in terms of base decline.” – *March 2016 Strategy Update*

#### What the oil service companies are saying

**Weatherford:** “As well production decline rates accelerate and reservoir productivity complexities increase, our clients will continue to face challenges associated with decreasing the cost of extraction activities and securing desired rates of production. [...] We have long said that after a lag, decline rates would accelerate, that the effects were underestimated and the industry was producing at near capacity, which is something none of us have ever experienced. We’ll also add in that the industry will not be able to manage required oil demand as early as 2017.” – *May 2016, 1Q16 conference call*

**EnSCO:** “When oil prices went up above \$80 or \$100 a barrel, although a lot of headline attention went to the big new field developments and the FID, what was happening that people were doing a huge amount of in-field work. **They were drilling infield wells, recompleting old wells, drilling step-out wells. That has effectively stopped and, as a consequence of that, we’re going to start to see, very rapidly, decline rates on existing fields.**” – *April 2016, 1Q16 conference call*

**Schlumberger:** “[The] apparent resilience in production outside of OPEC and North America is in many cases driven by producers opening the taps wide open to maximise cash flow, which also means that we will likely see higher decline rates after these short-term actions are exhausted. So while the global oil market is still being weighed down by fears of reduced growth in Chinese demand, the magnitude of additional Iranian exports and the continued various trends in global oil inventories, we still expect a positive movement in oil prices during 2016, with specific timing being a function of the shape of the non-OPEC decline rates.” – *January 2016, 4Q15 conference call*

**Schlumberger:** “Production in North America continues to fall as decline rates are becoming more pronounced, while the mature non-OPEC production is now falling in a number of regions. [...] [The] the magnitude of the E&P investment cuts are now so severe that it can only accelerate production decline and the consequent upward movement in oil price[s]”. – *April 2016, 1Q16 conference call*

**Technip:** “There is now a strong consensus that the current investment levels are insufficient to sustain production and **we are starting to observe a significant production decline at field, company or even country levels.**” – *July 2016, 2Q16 conference call*

**Core Labs:** “With long-term worldwide spare capacity near zero, Core believes worldwide producers will not be able to offset the estimated 3.3% net production decline curve rate in 2016, leading to falling global oil production in the year. These net decline curve rates are supported by recent IEA data indicating a decline of 300,000 barrels of production per day from February to March of 2016, which is the third consecutive month of global decline. Core believes crude oil markets rationalise in the second half of 2016 with price stability followed by price increases returning to the energy complex. **The immutable laws of physics and thermodynamics mean that the production decline curve always wins, and it never sleeps.**” – *April 2016, 1Q16 conference call*

**Diamond Offshore:** “And then you look at the decline curves that we’re experiencing, and many people or many commentators in our space have differing views, but it’s anything from 3.8% per year through to maybe 5% or 6%.” – *June 2016*



# Notes

# Notes

# Disclosure appendix

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