# THE GUINNESS GLOBAL ENERGY REPORT

Developments and trends for investors in the global energy sector | May 2018

## GUINNESS GLOBAL ENERGY FUND

Fund size: $261m (30.4.2018)

The Guinness Global Energy Fund invests in listed equities of companies engaged in the exploration, production and distribution of oil, gas and other energy sources. We believe that over the next twenty years the combined effects of population growth, developing world industrialisation and diminishing fossil fuel supplies will force energy prices higher and generate growing profits for energy companies.

The Fund is run by Will Riley, Jonathan Waghorn and Tim Guinness. The investment philosophy, methodology and style which characterise the Guinness approach have been applied to the management of energy equity portfolios since 1998.

**Important information about this report**

This report is primarily designed to inform you about recent developments in the energy markets invested in by the Guinness Global Energy Fund. It also provides information about the Fund's portfolio, including recent activity and performance. This document is provided for information only and all the information contained in it is believed to be reliable but may be inaccurate or incomplete; any opinions stated are honestly held at the time of writing, but are not guaranteed. The contents of the document should not therefore be relied upon. It is not an invitation to make an investment nor does it constitute an offer for sale.

# HIGHLIGHTS FOR APRIL

## OIL

### Brent and WTI up on tightening market; Iran supply risk

Brent and WTI both up over the month; WTI rose from $64.9/bl to $68.6/bl; Brent rose from $69.1/bl to $74.9/bl. The call on OPEC production has risen thanks to upgraded oil demand, OPEC sticking to quotas and Venezuela declining. The risk that Iranian oil exports decline if US President Trump removes the waiver on sanctions in relation to Iran's nuclear deal is also looming and has added some risk premium to prices.

## NATURAL GAS

### US gas prices up slightly; market undersupplied

Henry Hub prices were slightly higher on the month, rising from $2.73/mcf to $2.76/mcf. A cold end to winter has left US natural gas inventories close to 10 year lows, but onshore US supply in February 2018 (latest EIA data) now 84.9 bcf/day, 8.6 bcf/day higher than twelve months ago.

## EQUITIES

### Energy outperforms the broad market

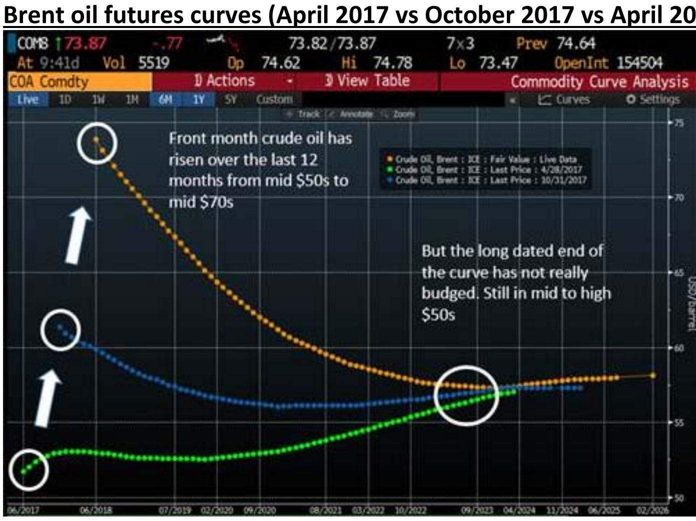
The MSCI World Energy Index rose in April by 9.4%, outperforming the MSCI World Index which rose by 1.2% (all in US dollar terms). For the year to April 30 2018, the MSCI World Energy Index is ahead of the MSCI World by 3.7%.

## CHART OF THE MONTH

### Oil futures curve has shifted strongly into backwardation

Since April 2017, the Brent spot oil price has risen from the low $50s/bl to the low $70s/bl. During this period, long dated prices have barely budged, with the five year forward price for Brent up by around $1/bl. The overall futures has therefore shifted from contango to sharp backwardation. In other words, the market remains sceptical that longer-term prices of more than $50/bl are required, which has muted the recovery in energy equities. We expect the longer dated part of the Brent futures curve to rise over time.

**Brent oil futures curves (April 2017 vs October 2017 vs April 2018)**




Source: Bloomberg; Guinness Asset Management


Tel: +44 (0) 20 7222 5703
Email: info@guinnessfunds.com
Web: guinnessfunds.com


GUINNESS ASSET MANAGEMENT

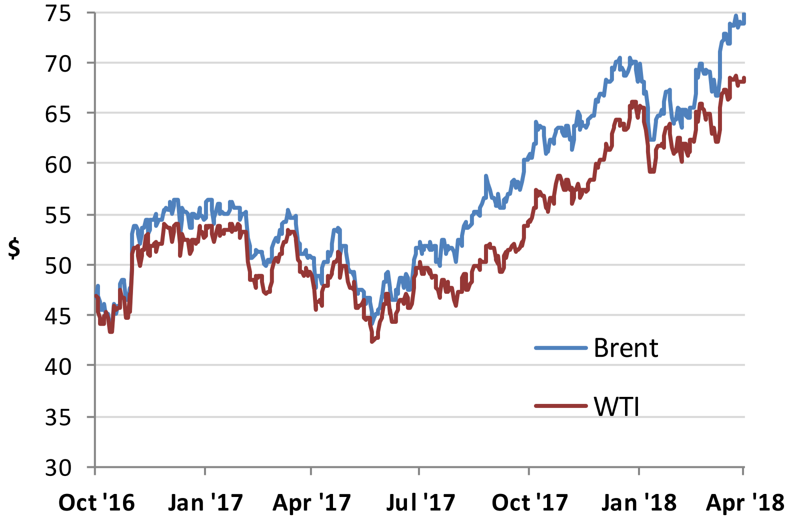
**Contents**


1. APRIL IN REVIEW ........ 2
2. MANAGER'S COMMENTS ........ 7
3. PERFORMANCE Guinness Global Energy Fund ........ 12
4. PORTFOLIO Guinness Global Energy Fund ........ 13
5. OUTLOOK ........ 16
3. APPENDIX Oil and gas markets historical context ........ 27


# 1. APRIL IN REVIEW

## i) Oil market

***Figure 1: Oil price (WTI and Brent $/barrel) 18 months October 31 2016 to April 30 2018***




*Source: Bloomberg LP*

The West Texas Intermediate (WTI) oil price started April at $64.9/bl and, after trading lower for the first few days, rose steadily higher to close the month at $68.6/bl. WTI has averaged $63.8/bl so far in 2018, having averaged $51 in 2017, $43.4 in 2016, $48.7 in 2015 and $93.1 in 2014.

Brent oil traded in a similar pattern, opening at $69.1/bl and rising to close the month at $74.9/bl. Brent has averaged $68.2/bl so far in 2018. The gap between the WTI and Brent benchmark oil prices widened during the month, ending April at $6.3/bl, having been around $4/bl in March.

**Factors which strengthened WTI and Brent oil prices in April:**

- **Widening call on OPEC supply**

  The IEA reported OPEC production to be 31.5m b/day in March, and market surveys suggest a slightly lower figure in April. We calculate the call on OPEC this year to be 32.4m b/day, meaning the supply 'gap' is around 0.9m b/day, up from around 0.3m b/day at the start of the year. The growing call on OPEC has been caused by three main factors - upgrades to global demand forecasts, OPEC supply discipline, and very weak production from Venezuela.

- **Threat of renewed Iranian sanctions**

  US President Trump's threat to unwind the 2015 Iran nuclear deal has raised the prospect of a further drop in OPEC production. After sanctions against Iran were waived in early 2016, Iran's oil supply has recovered from 2.8m b/day to its current quota of 3.8m b/day. Should the waiver be removed on 12 May, as Trump is contemplating, Iran's production would fall sharply again towards 3m b/day. If this occurred, we would expect other members of OPEC to make up some of the shortfall (the rest of OPEC is holding back 1.15m b/day), but it would add to market tightness in the shorter term.

**Factors which weakened WTI and Brent oil prices in April:**

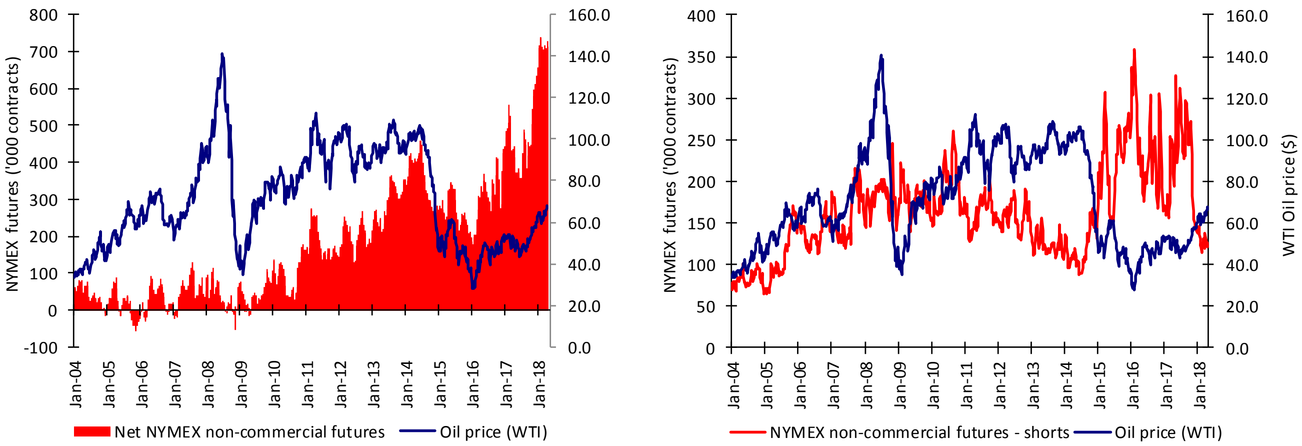
- **Rise in US onshore drilling rig count**
  The US oil directed drilling rig count rose by 17 rigs during April, up to 825 rigs. This compares to a low in the middle of 2016 of 316 rigs, and an average rig count in 2017 of 703 rigs. Whilst not a significant jump, the rig count has now risen over the last year by around 20%, which will result in some acceleration in US onshore oil supply.

- **Increased US onshore oil supply**
  At the start of May, the EIA reported that US onshore production increased by 166k b/day during February 2018. This keeps year over year growth for the US onshore system at around 1.2m b/day. Using production guidance data provided by the larger shale producers, we expect the US onshore oil system to maintain a similar pace of growth for the rest of the year. Whilst this level of growth would be significant, it does not represent much of a change versus expectations 9-12 months ago, given current oil prices.

**Speculative and investment flows**

The New York Mercantile Exchange (NYMEX) net non-commercial crude oil futures open position (WTI) fell slightly in April, ending the month at 712,000 contracts long versus 716,000 contracts long at the end of March. Typically there is a positive correlation between the movement in net position and movement in the oil price. The gross short position reduced from 138,000 contracts to 126,000 contracts. This short position is now at relatively low level versus those seen in the last couple of years.

***Figure 2: NYMEX Non-commercial net and short futures contracts: WTI January 2004 – April 2018***

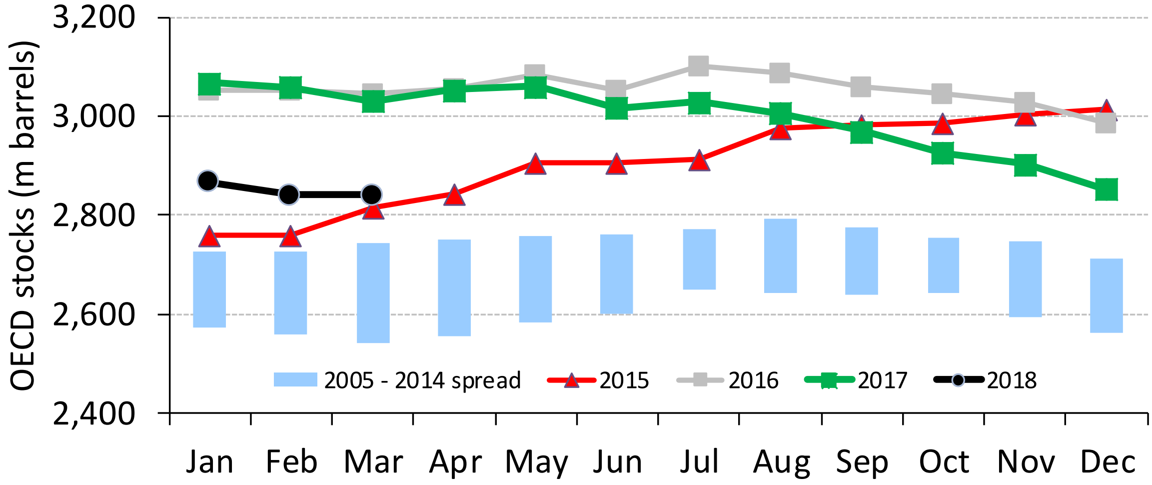



*Source: Bloomberg LP/NYMEX/ICE (2018)*

**OECD stocks**

OECD total product and crude inventories at the end of March (the latest data point available) were estimated by the IEA to be 2,840m barrels, down by 1m barrels versus the level reported for February. This compares to a 10-year average build for March of 2m barrels. Inventories have been tightening since the middle of 2017, and remain around 100m barrels above the 'normalised' (pre-2015) range. We expect them to continue to tighten over 2018, predominantly as a result of OPEC's quota system.

***Figure 3: OECD total product and crude inventories, monthly, 2004 to 2018***



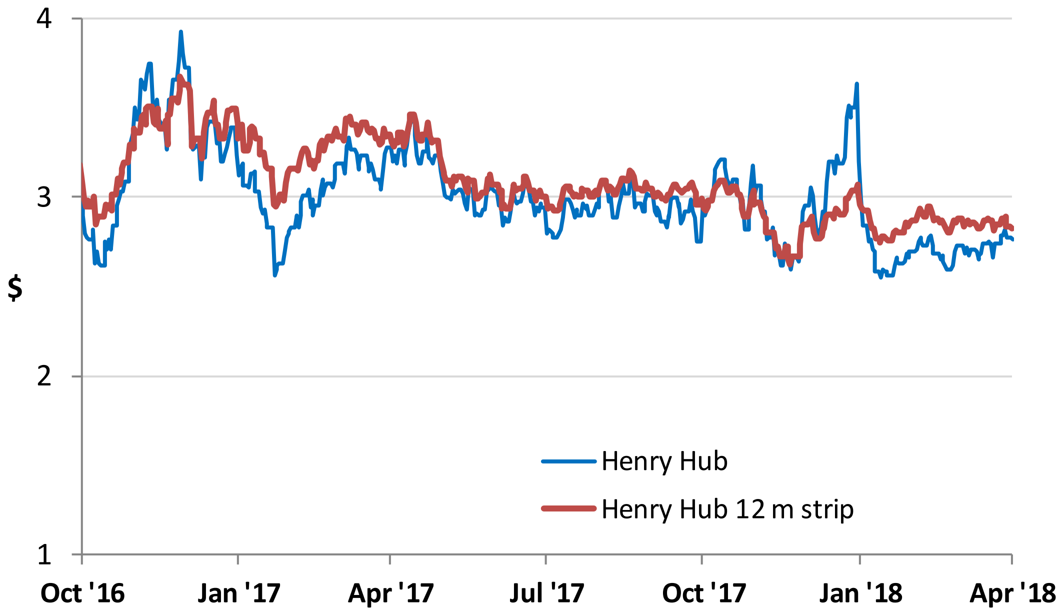

*Source: IEA Oil Market Reports (April 2018 and older)*

## ii) Natural gas market

The US natural gas price (Henry Hub front month) opened March at $2.73/mcf (1,000 cubic feet). The price fluctuated through the month in a tight band between $2.68 and $2.82, before closing at $2.76/mcf. The spot gas price has averaged $2.81/mcf so far in 2018, which compares to an average gas price of $3.02 in 2017, $2.55/mcf in 2016 and $2.61/mcf in 2015. The price averaged around $3.90/mcf over the preceding five years (2010-2014).

The 12-month gas strip price (a simple average of settlement prices for the next 12 months' futures prices) was down slightly over the month, opening at $2.88/mcf and closing at $2.82/mcf. The strip price averaged $3.12 in 2017 and $2.84 in 2016, having averaged $2.86 in 2015, $4.18 in 2014 and $3.92 in 2013.

***Figure 4: Henry Hub gas spot price and 12m strip ($/Mcf) October 31 2016 to April 30 2018***



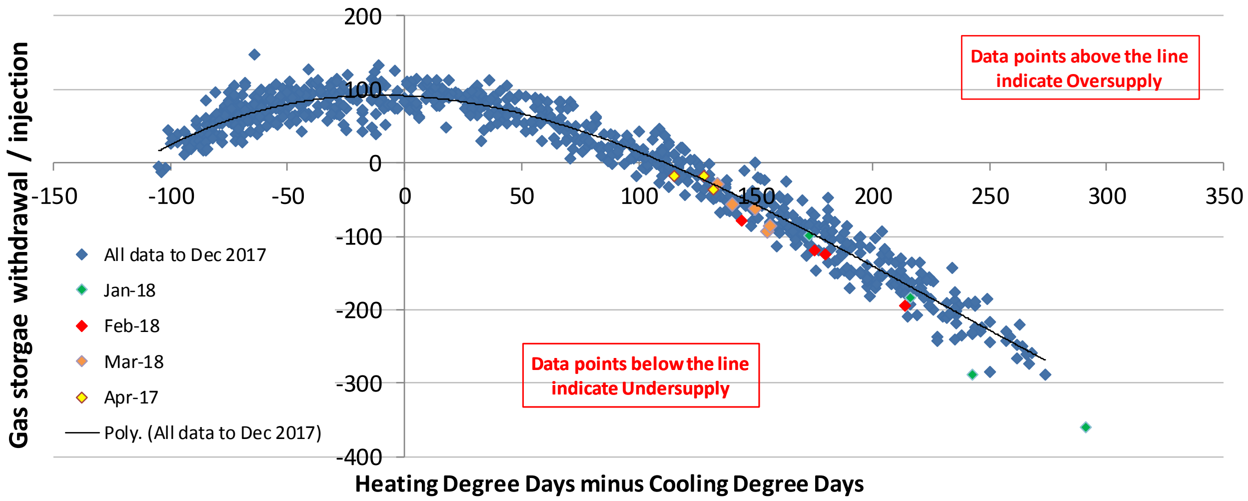

*Source: Bloomberg LP*

**Factors which strengthened the US gas price in April included:**

- **Structurally undersupplied market**
  Adjusting for the impact of weather in March, the most recent injections of gas into storage suggest the market is, on average, around 1 bcf/day undersupplied (as indicated by the yellow dots on the graph below).

- **Cold end to winter**
  US natural gas inventories tightened in April, falling by around 70 Bcf versus a seasonal average build of 80 Bcf. An unusually cold finish to winter contributed to the decline.

***Figure 5: Weather adjusted US natural gas inventory injections and withdrawals***




*Source: Bloomberg LP; Guinness Asset Management*

- **Strong US onshore natural gas production**
  Onshore US natural gas production averaged 84.9 Bcf/day in February 2018 (the latest available data point), up by 1.6 Bcf/day on the level reported for January. Onshore production has risen by 8.6 Bcf/day versus the level reported twelve months before, the highest year-on-year growth recorded. Rising associated gas supply from shale oil, and a pickup of activity in the Marcellus basin, are the key reasons for the rise in production: both look set to continue for the rest of 2018.

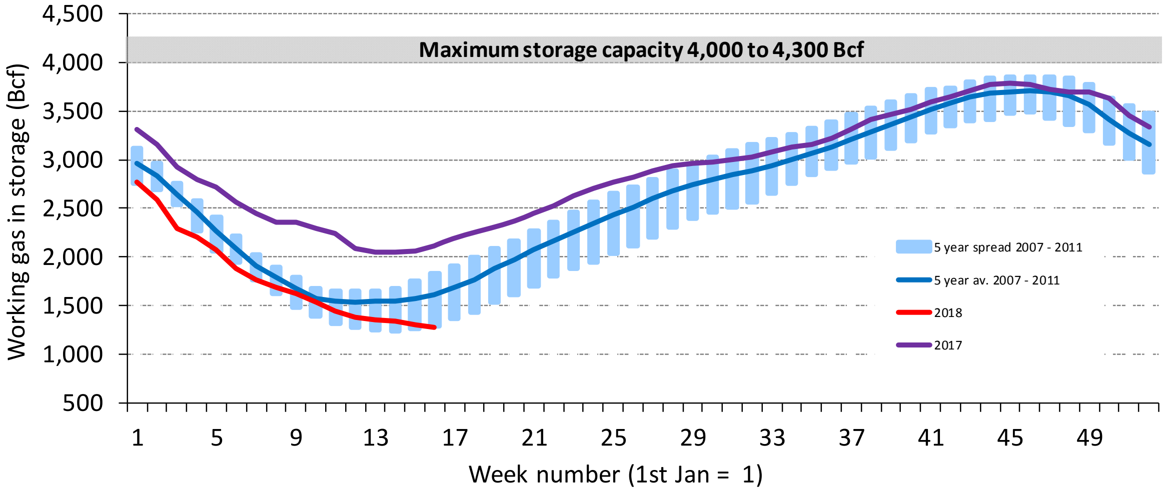
**Natural gas inventories**

Swings in the balance for US natural gas should, in theory, show up in movements in gas storage data. Natural gas inventories at the end of April were reported by the EIA to be 1.28tcf. The withdrawal season started with inventories peaking at 3.8tcf in mid-November, the lowest starting point of the winter season for US gas inventories since November 2014. Exceptionally cold weather and an undersupplied market has brought inventories back from being at the top of the ten year range (in November and December) to being below seasonal norms during April.



***Figure 6: Deviation from 5yr gas storage norm vs gas price 12-month strip (H. Hub $/Mcf)***




*Source: Bloomberg; EIA (April 2018)*

# 2. MANAGER'S COMMENTS

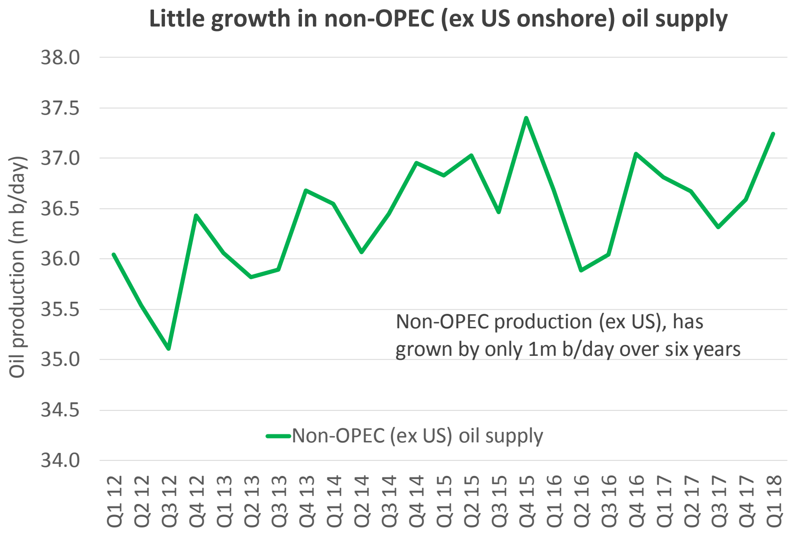
## Mind the 'non-OPEC oil supply' gap

**The largest slump in capex for over 20 years has caused a deterioration in the long term outlook for non-OPEC production outside the US. Existing fields have declined faster during the oil price fall and there is a shortfall of new projects coming online in this area, which represents over half of current world oil supply. Assuming that world oil demand continues to grow, we see an increasing 'call' on US unconventional oil and see the need for higher long term oil prices to incentivise the development of new large scale non-OPEC conventional oil fields.**

### Non-OPEC production (ex US) has been muted over the last five years

Oil production in the non-OPEC world (ex US onshore) comprises 'conventional' (e.g. deepwater offshore wells) and 'unconventional' supply (e.g. Canadian oil sands). The common strand tends to be that the oil comes from large, capital intensive projects, where the lead time between an investment decision being made and first production is normally at least three years.

Despite the oil price averaging over $100/bl between 2010 and 2014, non-OPEC (ex US onshore) production has only grown by around 1m b/day over the last six years. Most of the growth can be attributed to Canada, where large oil sands projects have rolled into production, and Brazil, where sub-salt offshore developments have ramped up, albeit far more slowly than the Brazilian government planned. But beyond that, new projects have only been successful in plugging the gap of declines in existing production. There has been a very limited supply response from non-OPEC (ex US onshore) despite high oil prices.



Source: Bloomberg, PIW

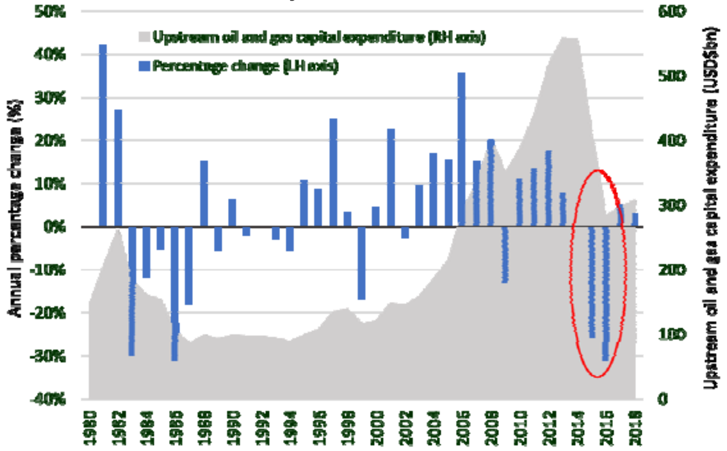
### Substantially lower reinvestment means the non-OPEC (ex US onshore) production outlook is worsening

Significant capital spending reductions since 2014, as a result of the decline in oil prices, are likely to result in non-OPEC conventional oil production moderating and declining in the coming years. The reason is two-fold: existing fields producing less as a result of **higher production decline rates,** and new oil projects bringing less production as a result of **many of those projects being delayed or cancelled.**

## Upstream investment has fallen at the fastest rate for over twenty years

The average oil price in 2015-2017 was over 50% lower than the average oil price in 2010-2014, so it is no surprise that oil industry reinvestment levels are down 40% on average over the period 2016-2018 compared to 2012-15. This reduction is the biggest correction in capex on oil and gas projects that we have seen in the industry since the slump of the early 1980s.

**The largest decline in upstream oil and gas capex for over 20 years**



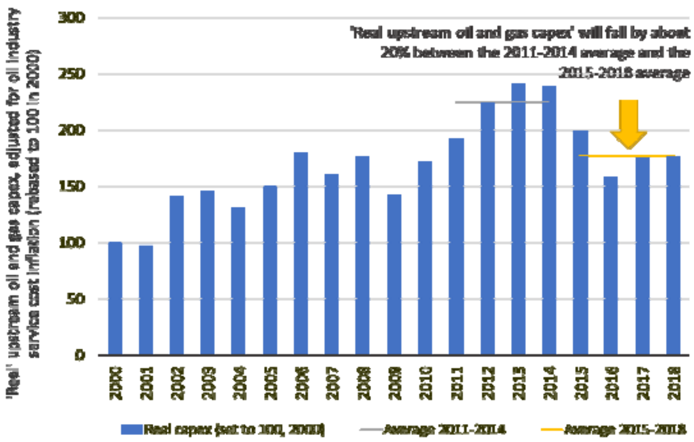

Source: Bloomberg, JP Morgan, BP Statistical Review

In a period of declining oil prices, the initial reaction from producing companies is typically to cut reinvestment, cut operating costs and (certainly for the larger companies) defend dividend commitments as strongly as possible. The time lag of the investment cycle means that capex can be cut with limited impact on existing production; however the cuts will ultimately impact future production. The question becomes; if capex in the conventional oil and gas world fell by over 40% in 2015-2017, and is showing only very limited signs of recovering at the moment, how much will future oil supply be affected?

There are two factors that we need to consider to properly adjust for these changes in capital expenditure levels; firstly, **adjusting for oil and gas industry inflation** and secondly adjusting for the **split between oil and gas** projects.

In terms of **industry inflation adjustment**, one key effect of the r investment is that the per unit pricing of oilfield services has fallen sharply, since there has been excess service capacity. This cost deflation has the effect of making every dollar spent by the upstream companies 'go further', and we can see this in development costs of the upstream companies falling appreciably. The peak of the oil service inflationary cycle was 2014, ending a 14 year period when oil service costs inflated at an average rate of 6% p.a. Since 2014, oil services prices have fallen by 10% p.a. and 2018 is likely to be the first year where we see a small increase in pricing. The deflationary pricing cycle appears to have been swift and is now just about over. Combining actual capex changes and adjusting for inflation, we find that real upstream activity (industry inflation adjusted upstream spending) will fall by about 20% on average in the 2015-2018 period compared to the 2011-2014 period. This takes real upstream spending back to what we saw in the 2006-2010 period.

**Industry inflation adjusted upstream oil & gas capex down about 20%**




Source: Bloomberg, JP Morgan, Guinness Asset Management

Secondly, when we allow for the allocation of upstream **capital expenditure between oil and gas projects**, we find that industry inflation-adjusted capex on oil-oriented projects is likely to be down by around 25% on average in the 2015-2018 period vs the 2010-2014 period. Over the last few years, there has been increasing focus from the larger oil and gas companies to developing gas projects, especially large scale LNG projects, in preference to larger oil projects. Whilst it is difficult to be precise about the split between oil and gas capex, we estimate that about 50% of capex is currently being spent on gas projects and according to the 'Top Projects' analysis carried out by Goldman Sachs, around 60% of new project capex being sanctioned between 2018-2020 will be on gas projects. The larger energy companies have an increasing preference towards gas projects and the resulting reduction in oil capital expenditure will put even more pressure on oil production in the coming years.

## Impact #1 of lower investment: increasing declines on existing oil production

The simple fact is that without investing capital consistently, every oil field will decline as the pressure within the reservoir depletes. The annual level of depletion is measured as the 'decline rate' and is presented on a %p.a. basis. Typically speaking, a conventional oilfield will increase production to a plateau level and then sustain this for three or four years before declines start. Once it starts, production decline is difficult to overcome, but this does not stop producers from seeking economic ways to drill infill wells or pursue reservoir injection in order to fight the laws of physics. Companies can offset the decline (and bring forward in time the ultimate recoverability of oil) but cannot overcome the decline.
Different types of oil fields have varying decline profiles. Heavy oil upgrader projects have very low decline rates, deepwater offshore fields have high decline rates and unconventional (shale oil) wells have exceptionally high decline rates. A 'typical' oil field might have a decline rate in the 2-7% p.a. range (after maintenance and extending capex) and a natural decline rates (before maintenance capex) of around 15% p.a. These are generalisations but useful rules of thumb.
The level of reinvestment has an impact on the decline rate of any individual field and industry research indicates that decline rates across countries and regions typically increase during an oil price fall. There is a time lag to this effect but it appears that non-OPEC (ex US onshore) decline rates have increased again as a result of recent years of underinvestment as discussed above.

Source: Bloomberg

The 'poster child' for the impact of natural declines (combined with a lack of new investment) in the past few years has been Mexico. Mexico's largest oilfield, Cantarell, has been in decline since the mid 2000s, and a failure to find replacement production has seen overall oil production declines in the country accelerate, particularly since 2014. The average annual (net) decline rate since the end of 2014 has been 7%. In response, Mexico has opened up its offshore oilfields to foreign investment, a process that started in 2015, but it will be some time before this translates into meaningful development.

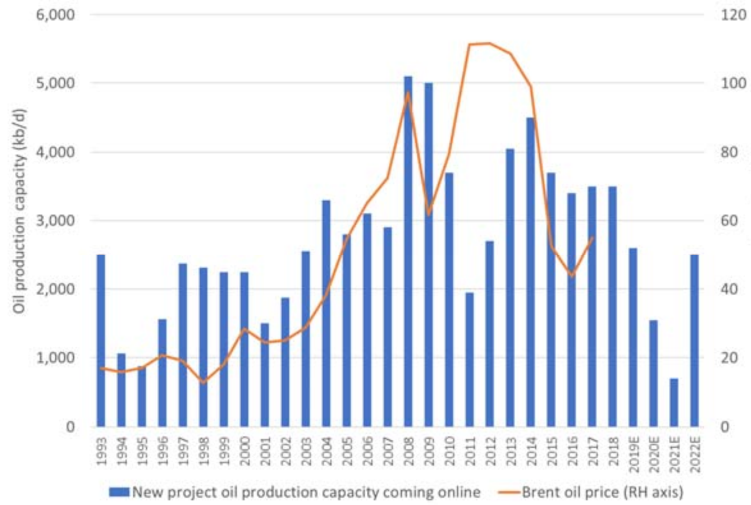
We have analysed historic non-OPEC (ex US onshore) oil production and new project start-ups over the last twenty five years to measure an underlying decline rate and have found it to be in a range of 1% to 8% p.a. since 2000 with an average level of around 5% p.a. We believe that a long term estimate of around 6% p.a. is a sensible assumption after considering reinvestment levels and the increasing share of production coming from higher decline deepwater offshore oil fields. This gives us an assumed starting point that the non-OPEC (ex US onshore) region currently needs to replace around 3 million barrels per day of production each year to keep overall oil production flat.

## Impact #2 of lower real oil investment: new projects are delayed or cancelled

The more apparent effect of reduced real oil industry investment is the lower level of new projects being sanctioned, developed and ultimately starting production. Combining various industry research papers, we have created a time series of historic oil field developments and the production associated with them. Years of high oil price (and associated high levels of free cash flow generation) are generally associated with higher levels of project sanction and production start-ups (and vice versa). Since 1993, we estimate that new non-OPEC (ex-US onshore) oil projects added at peak in excess of 5m b/day of new production capacity, with an average level of new additions over the period of just under 3m b/day per annum.

As a result of lower industry inflation adjusted oil investment levels, we expect that the oil production capacity added in 2019, 2020 and 2021 will be **well** below the average level added since 1993.

If oil prices sustain over $60/bl and confidence returns, we expect to see an increased level of 'final investment decisions' (FIDs) in non-OPEC (ex US onshore) projects. However, these FIDs would be unlikely to impact the low level of project start-ups expected in 2019-21 because the typical non-OPEC conventional oil project takes in excess of three years from FID to the start of production. We could see an improvement in 2022 (and we have modelled a significant one as you can see above) but the downdraft in 2019-2021 is coming.



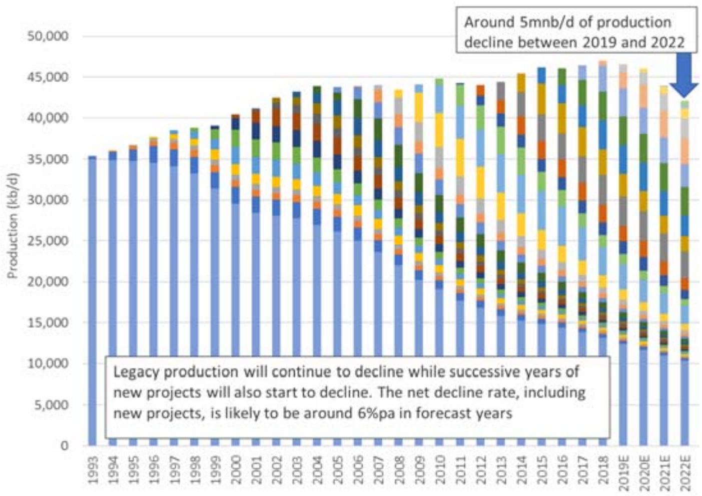

Source: Kessler Energy, Goldman Sachs, Credit Suisse, Piper Jaffray, Guinness Estimates

## Higher declines and lower new project start ups will soon cause a problem

The 25% plus reduction in real oil-oriented capex is causing higher decline rates and a reduced level of new oil project sanctions and will result in the outlook for non-OPEC (ex US onshore) oil production to be increasingly under pressure.

We estimate that non-OPEC (ex-US onshore) oil production will reach a peak of around 47m b/day in 2018 (ex biofuels and processing gains) as a result of the higher level of new project start-ups associated with the higher oil price environment of 2010-2014. As these new projects roll over, and the base continues to decline at around 6% p.a., we expect to see a relatively sharp decline in non-OPEC (ex US onshore) oil production. It would be wrong to pretend that we can be precise about the outcome of these effects, but our modelling does suggest non-OPEC (ex-US onshore) production could fall by around five million barrels per day over the four year period from 2019 to 2022. Higher oil prices may result in higher 2018 FIDs but this is unlikely to have any impact on the production outlook before 2022.

**Non-OPEC (ex US onshore) faces a decline**




Source: Kessler Energy, Goldman Sachs, Guinness Estimates

## Conclusion: higher long dated oil prices required to incentivise spending to offset the declining non-OPEC (ex US onshore) oil profile

As non-OPEC (ex US onshore) oil matures and declines, the global oil industry will have to find other ways to replace the supply shortfall and satisfy the likely growing global demand for crude oil. The requirement will predominantly fall on **OPEC** and the **US onshore** to satisfy this growing gap:

1. **OPEC** will taper 'missing' quota barrels back into the market, then gradually increasing production and exports again.

   OPEC currently has 1.2m b/day of oil on the sidelines – production that was removed from the market at the start of 2017 as quotas were lowered. OPEC representatives have talked of 'tapering' this oil supply back into the market once global oil inventories have fully corrected lower, potentially later in 2018 or 2019. We expect this process to be managed carefully by Saudi, to avoid a return to oversupply. Beyond the next year or two, with the non-OPEC (ex US onshore) declines that we are forecasting, we see OPEC attempting to maintain a broadly flat market share, as a result of International Oil Company investment in new projects. However, limited spare capacity means that the group is poorly placed versus history to maintain a balanced market should we see an external supply shock.

2. **US onshore supply** will increase as higher oil prices incentivise a greater level of activity.

   The US onshore industry has proved itself to be dynamic in recent years with activity, investment and production adjusting rapidly to changes in oil prices. We believe that the US onshore will be required to be a flexible supply source in the coming years as well, in order to maintain a balanced global oil market. We also believe that the US system can continue to grow successfully, but it becomes a question of the oil price needed to incentivise that growth. Over the past twelve months, with WTI averaging in the high $50s, the US onshore oil system has been growing by around 1m b/day. This may be sufficient production currently, but if the 'call' on the US rises to, say, annual growth of 1.5m b/day or 2m b/day at points, then a higher price will be required and one that is certainly higher than the level seen in the current forward curve for oil.

   **History shows that global oil supply and demand factors will adjust to achieve balance and that price is a key factor in creating that balance. Our conclusion from this piece is that non-OPEC (ex US) production, which comprises over half of world oil supply, faces significant growth challenges over the next few years. This issue will become more acute from 2020 onwards. We believe, therefore, that the next oil upcycle, supporting investment in the industry and price, will be required to incentivise supply. Spot oil prices have risen this year, reflecting a tighter market in the short-term, but it is longer dated oil prices that will need to rise to incentivise investment in long-term non-OPEC and OPEC production, as well as shorter cycle US shale oil.**

# 1) PERFORMANCE Guinness Global Energy Fund

The main index of oil and gas equities, the MSCI World Energy Index, was up by 9.4% in March, while the MSCI World Index rose by 1.2%. The Fund was up by 11.7% (class E) in the month, outperforming both indices (all in US dollar terms).

Within the Fund, March's strongest performers were Newfield, QEP, Oasis, Helix and Valero, while the weakest performers were Gazprom, Enbridge, Schlumberger, Sunpower and OMV.

## Performance (in USD) 30/04/2018

### Annualised

| % returns | 1 year | 3 years | 5 years | 10 years | 1999 to date |
|---|---|---|---|---|---|
| **Guinness Global Energy** | 16.7 | -3.7 | -1.3 | -2.4 | 10.4 |
| **MSCI World Energy Index** | 18.0 | 1.4 | 1.7 | 0.2 | 7.4 |

### Calendar year

| % returns | 2018 | 2017 | 2016 | 2015 | 2014 | 2013 | 2012 | 2011 | 2010 | 2009 | 2008 | 2007 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Guinness Global Energy** | 6.5 | -1.3 | 27.9 | -27.6 | -19.1 | 24.4 | 3.0 | -13.6 | 15.3 | 61.8 | -48.2 | 37.6 |
| **MSCI World Energy Index** | 3.7 | 5.9 | 27.6 | -22.1 | -11.0 | 18.8 | 2.5 | 0.7 | 12.5 | 27.0 | -37.7 | 30.4 |

*Source: Guinness Asset Management and Financial Express, bid to bid, gross income reinvested, in US dollars*

Calculation by Guinness Asset Management Limited, simulated past performance prior to 31.3.08, launch date of Guinness Global Energy Fund. The Guinness Global Energy investment team has been running global energy funds in accordance with the same methodology continuously since November 1998. These returns are calculated using a composite of the Investec GSF Global Energy Fund class A to 29.2.08 (managed by the Guinness team until this date); the Guinness Atkinson Global Energy Fund (sister US mutual fund) from 1.3.08 to 31.3.08 (launch date of this Fund), the Guinness Global Energy Fund class A (1.49% OCF) from launch to 02.09.08, and class E (1.24% OCF) thereafter. Performance would be lower if an initial charge and/or redemption fee were included.

**Past performance should not be taken as an indicator of future performance. The value of this investment and any income arising from it can fall as well as rise as a result of market and currency fluctuations as well as other factors. You may lose money in this investment.**

**Returns stated above are in US dollars; returns in other currencies may be higher or lower as a result of currency fluctuations. Investors may be subject to tax on distributions.**

**The Fund's Prospectus gives a full explanation of the characteristics of the Fund and is available at www.guinnessfunds.com.**



# 2) PORTFOLIO Guinness Global Energy Fund

**Buys/Sells**

In April we rebalanced the portfolio. There were no stock switches.

**Sector Breakdown**

The following table shows the asset allocation of the Fund at **April 30 2018**.

| (%) | 31 Dec 2009 | 31 Dec 2010 | 31 Dec 2011 | 31 Dec 2012 | 31 Dec 2013 | 31 Dec 2014 | 31 Dec 2015 | 31 Dec 2016 | 31 Dec 2017 | 31 Mar 2018 | *Change YTD* |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Oil & Gas** | **98.2** | ***93.3*** | ***97.9*** | ***97.3*** | ***93.7*** | ***93.7*** | ***95.1*** | ***96.7*** | ***98.4*** | ***97.0*** | ***0.3*** |
| Integrated | 35.9 | 33.0 | 30.9 | 30.4 | 29.2 | 27.0 | 30.4 | 32.5 | 28.6 | 28.3 | *-4.2* |
| Integrated – Can & Em Mkts | 11.9 | 8.2 | 8.8 | 8.4 | 9.4 | 10.3 | 11.1 | 14.3 | 14.2 | 14.1 | *-0.2* |
| Exploration & production | 32.8 | 37.1 | 41.1 | 40.3 | 35.4 | 36.2 | 36.5 | 35.4 | 37.0 | 37.1 | *1.7* |
| Oil & Gas Storage & Transportation | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.5 | 2.9 | *2.9* |
| Drilling | 8.5 | 6.1 | 5.9 | 7.1 | 6.4 | 3.3 | 1.5 | 2.2 | 1.9 | 1.7 | *-0.5* |
| Equipment & services | 5.9 | 5.4 | 6.1 | 7.4 | 9.8 | 13.4 | 11.4 | 8.6 | 9.5 | 9.1 | *0.5* |
| Refining and marketing | 3.2 | 3.5 | 5.1 | 3.7 | 3.5 | 3.5 | 4.2 | 3.7 | 3.7 | 3.8 | *0.1* |
| **Solar** | **0.0** | **3.2** | **1.3** | **1.2** | **2.6** | **3.7** | **4.7** | **0.9** | **1.4** | **1.4** | ***0.5*** |
| **Coal & consumables** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | ***0.0*** |
| **Construction & engineering** | **0.3** | **0.3** | **0.4** | **0.6** | **1.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | ***0.0*** |
| **Cash** | **1.5** | **3.2** | **0.4** | **0.9** | **2.7** | **2.6** | **0.2** | **2.4** | **0.2** | **1.6** | ***-0.8*** |
| **Total** | **100.0** | **100.0** | **100.0** | **100.0** | **100.0** | **100.0** | **100.0** | **100.0** | **100.0** | **100.0** | |

*Source: Guinness Asset Management*
*Basis: Global Industry Classification Standard (GICS)*

The Fund at April 30 2018 was on a price to earnings ratio (P/E) for 2018 of 16.7x versus the S&P 500 Index also at 16.7x as set out in the following table:

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Guinness Global Energy Fund P/E | 8.5 | 8.8 | 9.5 | 10.4 | 23.9 | 42.2 | 25.8 | 16.7 |
| S&P 500 P/E | 27.5 | 27.3 | 24.7 | 22.8 | 26.4 | 25.0 | 21.3 | 16.7 |
| Premium (+) / Discount (-) | *-69%* | *-68%* | *-62%* | *-54%* | *-9%* | *69%* | *21%* | *0%* |
| Average oil price (WTI $/bbl) | 95 | 94 | 98 | 93 | 49 | 43 | 51 | 57 |

*Source: Standard and Poor's; Guinness Asset Management Ltd*

**Portfolio holdings**

Our integrated and similar stock exposure (c.43%) is comprised of a mix of mid cap, mid/large cap and large cap stocks. Our four large caps are Chevron, BP, Royal Dutch Shell and Total. Mid/large and mid-caps are ENI, Statoil, Hess and OMV. At April 30 2018 the median P/E ratios of this group were 18.8x/15.3x 2017/2018 earnings. We also have two Canadian integrated holdings, Suncor and Imperial Oil. Both companies have significant exposure to oil sands in addition to downstream assets.

Our exploration and production holdings (c.37%) give us exposure most directly to rising oil and natural gas prices. We include in this category non-integrated oil sands companies, as this is the GICS approach. The stock here with oil sands exposure is Canadian Natural Resources. The pure E&P stocks have a bias towards the US (Newfield, Devon, Oasis and QEP Resources), with four other names (Apache, Occidental, ConocoPhillips, Noble) having a mix of US and international production and one (Tullow) which is African focused. One of the key metrics behind a number of the E&P stocks held is low enterprise value / proven reserves. Almost all of the US E&P stocks held also provide exposure to North American natural gas.

We have exposure to four (pure) emerging market stocks in the main portfolio, though one is a half-position, and in total represent 12% of the portfolio. Two are classified as integrateds (Gazprom and PetroChina) and two as E&P companies (CNOOC and SOCO International). Gazprom is the Russian national oil and gas company which produces approximately a quarter of the European Union gas demand and trades on 4.1x 2018 earnings. PetroChina is one of the world's largest integrated oil and gas companies and has significant growth potential and, alongside CNOOC, enjoys advantages as a Chinese national champion. SOCO International is an E&P company with production in Vietnam.

The portfolio contains one midstream holding, Enbridge, North America's largest pipeline company. With the growth of onshore oil and gas production expected in the US and Canada over the next five years, we believe Enbridge is well placed to execute its pipeline expansion plans.

We have useful exposure to oil service stocks, which comprise around 11% of the portfolio. The stocks we own are split between those which focus their activities in North America (land driller Unit Corp) and those which operate in the US and internationally (Helix, Halliburton and Schlumberger).

Our independent refining exposure is currently in the US in Valero, the largest of the US refiners. Valero has a reasonably large presence on the US Gulf Coast and is benefitting from the rise in US exports of refined products seen in recent times.

Our alternative energy exposure is currently split between across two companies: JA Solar and Sunpower. JA Solar is a Chinese solar cell and module manufacturer whilst Sunpower is a more diversified US solar developer. We see them as well placed to benefit from the expansion in the solar market we expect to continue for a number of years.

## Portfolio at March 31st 2018 (for compliance reasons disclosed one month in arrears)

| Guinness Global Energy Fund 31 March 2018 | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Stock | Curr. | Country | % of NAV | 2009 B'berg mean PER | 2010 B'berg mean PER | 2011 B'berg mean PER | 2012 B'berg mean PER | 2013 B'berg mean PER | 2014 B'berg mean PER | 2015 B'berg mean PER | 2016 B'berg mean PER | 2017 B'berg mean PER | 2018 B'berg mean PER |
| **Integrated Oil & Gas** | | | | | | | | | | | | | |
| Chevron | USD | US | 3.69 | 22.2 | 12.2 | 8.5 | 9.3 | 10.3 | 11.9 | 31.3 | 82.2 | 27.5 | 18.4 |
| Royal Dutch Shell PLC | EUR | NL | 3.50 | 14.5 | 10.3 | 7.6 | 7.5 | 10.0 | 8.8 | 18.6 | 30.6 | 16.6 | 13.2 |
| BP PLC | GBP | GB | 3.61 | 8.7 | 6.0 | 6.0 | 7.4 | 9.2 | 11.0 | 19.3 | 36.9 | 22.0 | 14.9 |
| Total SA | EUR | FR | 3.50 | 12.9 | 10.1 | 9.0 | 8.6 | 9.6 | 9.8 | 12.5 | 14.7 | 13.7 | 11.7 |
| ENI SpA | EUR | IT | 3.88 | 10.0 | 7.6 | 7.3 | 7.1 | 11.4 | 13.2 | 61.9 | nm | 25.0 | 15.8 |
| Statoil ASA | NOK | NO | 3.56 | 13.6 | 10.2 | 8.9 | 7.9 | 9.7 | 13.6 | 33.0 | 167.5 | 17.5 | 15.4 |
| Hess Corp | USD | US | 3.67 | 26.4 | 9.8 | 8.4 | 8.6 | 8.8 | 12.1 | nm | nm | nm | nm |
| OMV AG | EUR | AT | 3.47 | 19.0 | 11.8 | 14.8 | 10.3 | 12.7 | 15.6 | 14.0 | 14.3 | 9.6 | 9.8 |
| | | | **28.90** | | | | | | | | | | |
| **Integrated / Oil & Gas E&P - Canada** | | | | | | | | | | | | | |
| Suncor Energy Inc | CAD | CA | 3.94 | 42.1 | 28.1 | 12.5 | 13.8 | 13.9 | 13.9 | 39.5 | nm | 23.8 | 18.5 |
| Canadian Natural Resources Ltd | CAD | CA | 3.69 | 16.8 | 16.7 | 17.5 | 25.5 | 18.0 | 11.8 | 291.4 | nm | 34.5 | 16.5 |
| Imperial Oil | CAD | CA | 3.68 | 17.2 | 14.9 | 9.3 | 8.2 | 10.6 | 8.9 | 19.2 | 56.7 | 26.7 | 19.4 |
| | | | **11.31** | | | | | | | | | | |
| **Integrated Oil & Gas - Emerging market** | | | | | | | | | | | | | |
| PetroChina Co Ltd | HKD | HK | 3.63 | 7.3 | 5.9 | 5.8 | 6.7 | 7.4 | 7.3 | 22.6 | 88.5 | 34.4 | 14.5 |
| Gazprom OAO | USD | RU | 3.50 | 5.2 | 4.1 | 2.8 | 2.9 | 2.7 | 4.2 | 3.0 | 3.9 | 4.4 | 3.9 |
| | | | **7.13** | | | | | | | | | | |
| **Oil & Gas E&P** | | | | | | | | | | | | | |
| Occidental Petroleum Corp | USD | US | 3.67 | 17.5 | 11.5 | 7.8 | 9.4 | 9.4 | 11.2 | 391.3 | nm | 72.3 | 23.8 |
| ConocoPhillips | USD | US | 3.91 | 16.4 | 10.0 | 7.0 | 10.4 | 10.6 | 11.2 | nm | nm | 95.2 | 21.7 |
| Apache Corp | USD | US | 3.54 | 6.9 | 4.1 | 3.2 | 4.0 | 4.7 | 6.9 | nm | nm | 363.0 | 28.2 |
| Devon Energy Corp | USD | US | 3.18 | 9.7 | 5.4 | 5.3 | 9.8 | 7.5 | 6.2 | 12.9 | nm | 17.3 | 24.8 |
| Noble Energy Inc | USD | US | 3.49 | 17.9 | 14.6 | 11.5 | 13.2 | 9.8 | 13.0 | 531.6 | nm | 1893.8 | 39.1 |
| QEP Resources Inc | USD | US | 1.85 | nm | 7.1 | 6.0 | 7.9 | 7.0 | 7.0 | nm | nm | nm | nm |
| Newfield Exploration Co | USD | US | 3.06 | 4.8 | 5.3 | 6.0 | 10.1 | 13.6 | 13.2 | 33.7 | 22.7 | 11.4 | 7.8 |
| Oasis Petroleum Inc | USD | US | 1.68 | nm | 48.2 | 9.8 | 5.5 | 2.9 | 3.3 | 10.2 | nm | nm | 32.1 |
| | | | **24.36** | | | | | | | | | | |
| **International E&Ps** | | | | | | | | | | | | | |
| CNOOC Ltd | HKD | HK | 3.73 | 13.8 | 7.9 | 6.0 | 6.4 | 6.5 | 7.8 | 23.4 | nm | 13.5 | 9.2 |
| Tullow Oil PLC | GBP | GB | 1.85 | 42.5 | 20.6 | 4.7 | 4.2 | 31.8 | nm | nm | nm | 14.4 | 13.3 |
| Soco International PLC | GBP | GB | 0.83 | 7.6 | 10.4 | 6.7 | 1.9 | 2.0 | 3.1 | nm | nm | nm | 27.5 |
| | | | **6.40** | | | | | | | | | | |
| **Midstream** | | | | | | | | | | | | | |
| Enbridge Inc | USD | CA | 3.44 | 48.7 | 42.0 | 37.9 | 34.9 | 32.2 | 29.5 | 26.6 | 24.7 | 29.9 | 24.4 |
| | | | **3.44** | | | | | | | | | | |
| **Drilling** | | | | | | | | | | | | | |
| Unit Corp | USD | US | 1.67 | 7.5 | 6.5 | 4.8 | 4.8 | 5.4 | 4.6 | nm | nm | 37.2 | 18.9 |
| | | | **1.67** | | | | | | | | | | |
| **Equipment & Services** | | | | | | | | | | | | | |
| Halliburton Co | USD | US | 3.81 | 35.9 | 23.3 | 14.0 | 15.8 | 15.1 | 11.9 | 31.8 | nm | 40.4 | 18.9 |
| Helix Energy Solutions Group Inc | USD | US | 1.46 | 10.0 | 11.0 | 3.9 | 3.1 | 5.4 | 3.0 | 34.3 | nm | nm | 46.3 |
| Schlumberger Ltd | USD | US | 3.60 | 23.8 | 23.5 | 17.9 | 15.5 | 13.6 | 11.7 | 19.3 | 56.1 | 44.3 | 30.3 |
| | | | **8.87** | | | | | | | | | | |
| **Solar** | | | | | | | | | | | | | |
| JA Solar Holdings Co Ltd | USD | US | 0.91 | nm | 0.9 | nm | nm | nm | 7.1 | 3.6 | 8.4 | 11.2 | 12.4 |
| Sunpower Corp | USD | US | 0.58 | 7.0 | 5.5 | 97.3 | 53.2 | 5.7 | 6.1 | 4.1 | nm | nm | nm |
| | | | **1.49** | | | | | | | | | | |
| **Oil & Gas Refining & Marketing** | | | | | | | | | | | | | |
| Valero Energy Corp | USD | US | 3.56 | nm | 58.5 | 23.3 | 19.0 | 22.6 | 15.2 | 10.6 | 25.2 | 19.0 | 13.0 |
| | | | **3.56** | | | | | | | | | | |
| **Research Portfolio** | | | | | | | | | | | | | |
| Cluff Natural Resources PLC | GBP | GB | 0.27 | nm | nm | nm | nm | nm | nm | nm | nm | nm | nm |
| EnQuest PLC | GBP | GB | 0.68 | nm | 4.6 | 5.3 | 1.6 | 1.8 | 3.3 | 31.5 | 2.1 | nm | 4.6 |
| JKX Oil & Gas PLC | GBP | GB | 0.18 | 0.7 | 0.7 | 0.9 | 1.2 | 2.3 | 6.3 | nm | nm | nm | 31.6 |
| Ophir Energy PLC | GBP | GB | 0.04 | nm | nm | nm | nm | nm | 2.3 | nm | nm | nm | nm |
| Reabold Resources PLC | GBP | GB | 0.35 | nm | nm | nm | nm | nm | nm | nm | nm | nm | nm |
| Shandong Molong Petroleum Machiner | HKD | HK | 0.05 | 5.7 | 2.2 | 3.1 | nm | nm | nm | nm | nm | nm | nm |
| Sino Gas & Energy Holdings Ltd | AUD | AU | 0.26 | nm | nm | nm | 115.0 | nm | 115.0 | nm | nm | nm | nm |
| | | | **1.85** | | | | | | | | | | |
| | | Cash | 1.02 | | | | | | | | | | |
| | | Total | 100 | | | | | | | | | | |
| | | **PER** | | 13.5 | 8.7 | 7.5 | 7.8 | 8.4 | 9.2 | 20.9 | 37.0 | 22.7 | 15.6 |
| | | Med. PER | | 13.7 | 10.1 | 7.4 | 8.4 | 9.6 | 9.8 | 23.0 | 25.2 | 24.4 | 18.4 |
| | | **Ex-gas PER** | | 14.6 | 9.4 | 8.2 | 8.0 | 9.0 | 9.8 | 20.3 | 33.8 | 22.0 | 15.2 |

The Fund's portfolio may change significantly over a short period of time; no recommendation is made for the purchase or sale of any particular stock.



# 3) OUTLOOK

## i) Oil market

The table below illustrates the difference between the growth in world oil demand and non-OPEC supply over the last 12 years, together with IEA forecasts for 2018.

| | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 IEA | 2018E IEA |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **World Demand** | 82.5 | 84.0 | 85.2 | 87.0 | 86.5 | 85.5 | 88.5 | 89.5 | 90.7 | 91.7 | 93.1 | 95.0 | 96.2 | 97.8 | 99.3 |
| **Non-OPEC supply** (includes Angola, Ecuador and Indonesia for periods when each country was outside OPEC[1]) | 50.3 | 50.4 | 51.3 | 50.5 | 49.6 | 51.4 | 52.7 | 52.8 | 53.3 | 54.5 | 56.6 | 58.1 | 56.8 | 57.5 | 59.3 |
| Angola supply adjustment[1] | -1.0 | -1.2 | -1.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Ecuador supply adjustment[1] | -0.5 | -0.5 | -0.5 | -0.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Indonesia/Gabon supply adjustment[2] | 1.0 | 0.9 | 0.9 | 1.0 | 1.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.6 | 0.6 | 0.6 |
| **Non-OPEC supply** (ex. Angola/Ecuador and inc. Indonesia for all periods) | 49.8 | 49.6 | 50.3 | 51.0 | 50.6 | 51.4 | 52.7 | 52.8 | 53.3 | 54.5 | 56.6 | 58.1 | 57.4 | 58.1 | 59.9 |
| OPEC NGLs | 4.2 | 4.3 | 4.3 | 4.3 | 4.5 | 5.1 | 5.5 | 5.9 | 6.4 | 6.1 | 6.4 | 6.6 | 6.8 | 6.9 | 7.0 |
| **Non-OPEC supply plus OPEC NGLs** (ex. Angola/Ecuador and inc. Indonesia for all periods) | 54.0 | 53.9 | 54.6 | 55.3 | 55.1 | 56.5 | 58.2 | 58.7 | 59.7 | 60.6 | 63.0 | 64.7 | 64.2 | 65.0 | 66.9 |
| **Call on OPEC-12[3]** | 28.5 | 30.1 | 30.6 | 31.7 | 31.4 | 29.0 | 30.3 | 30.8 | 31.0 | 31.1 | 30.1 | 30.3 | 32.0 | 32.8 | 32.4 |

[1] Angola joined OPEC at the start of 2007, Ecuador rejoined OPEC at the end of 2007 (having previously been a member in the 1980s)
[2] Indonesia left OPEC as of the start of 2009; rejoined at start of 2016, but is now suspended again
[3] Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi, U.A.E. Venezuela

Source: 2003 - 2008: IEA oil market reports; 2009 - 17: April 2018 Oil market Report

Global oil demand in 2017 was 10.8m b/day higher than the pre-financial crisis (2007) peak. This means the combined effect of the 2007/08 oil price spike and the 2008/09 recession was shrugged off remarkably quickly, thanks to growth in demand from emerging markets. The IEA forecast a rise of 1.5m b/day in 2018, which would take oil demand to an all-time high of 99.3m b/day.

### OPEC

In December 2011, OPEC-12 introduced a group-wide target of 30m b/day without specifying individual country quotas. At the date of the announcement, and in the period since, OPEC's production has been complicated by numerous issues: notably (1) erratic production from Libya, affected by the ongoing civil war; (2) depressed production in Iran due to western sanctions over its nuclear programme; (3) real difficulty in forecasting how Iraq might develop.

In response to lower Libyan, Iranian and Nigerian production, and to cope with rising global oil demand, the three key swing producers within OPEC (Saudi, Kuwait and UAE) each raised their production significantly, as the following table shows:

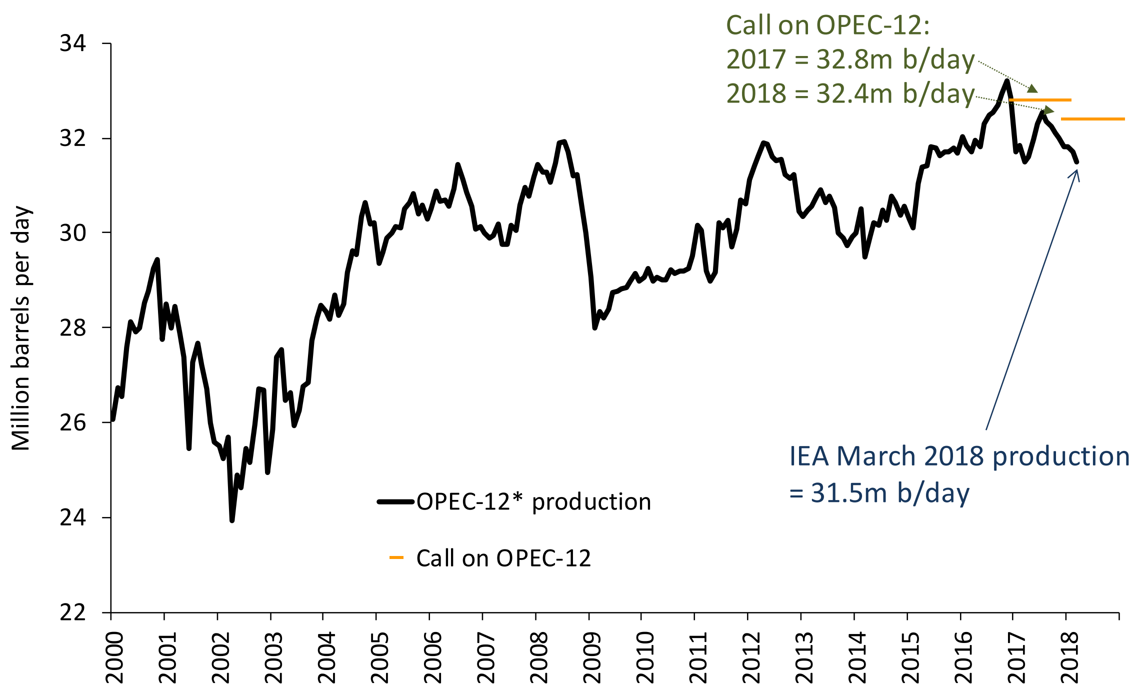
| ('000 b/day) | 31-Dec-10 | 30-Nov-14 | 31-Dec-16 | 31-Mar-18 | Current vs Dec 2010 (start of Arab Spring) | Current vs Nov 2014 (OPEC hold mkt share) | Current vs Dec 2016 (OPEC cut production) |
|---|---|---|---|---|---|---|---|
| **Saudi** | 8,250 | 9,650 | 10,480 | **9,870** | 1,620 | 220 | -610 |
| Iran | 3,700 | 2,780 | 3,730 | **3,810** | 110 | 1,030 | 80 |
| Iraq | 2,385 | 3,370 | 4,630 | **4,430** | 2,045 | 1,060 | -200 |
| UAE | 2,310 | 2,800 | 3,070 | **2,860** | 550 | 60 | -210 |
| Kuwait | 2,300 | 2,790 | 2,860 | **2,700** | 400 | -90 | -160 |
| Nigeria | 2,220 | 1,970 | 1,500 | **1,850** | -370 | -120 | 350 |
| Venezuela | 2,190 | 2,350 | 2,080 | **1,510** | -680 | -840 | -570 |
| Angola | 1,700 | 1,640 | 1,670 | **1,570** | -130 | -70 | -100 |
| Libya | 1,585 | 580 | 630 | **990** | -595 | 410 | 360 |
| Algeria | 1,260 | 1,100 | 1,110 | **1,000** | -260 | -100 | -110 |
| Qatar | 820 | 650 | 620 | **610** | -210 | -40 | -10 |
| Ecuador | 465 | 561 | 550 | **520** | 55 | -41 | -30 |
| **OPEC-12** | **29,185** | **30,241** | **32,930** | **31,720** | **2,535** | **1,479** | **-1,210** |

Source: Bloomberg, DOE

The effect from 2011 to the middle of 2014 was OPEC-12 (ex Indonesia) producing at around 30m b/day, plus or minus 1m b/day, in an attempt to keep the global oil market in balance.

From the second half of 2014, we moved into a period where the global oil balance became looser, driven principally by surging non-OPEC supply (+2.4m b/day in 2014 and +1.4m b/day in 2015). The effect of $100+ bbl oil, enjoyed for most of the 2011-2014 period, emerged in the form of an acceleration in US shale oil production and an acceleration in the number of large non-OPEC (ex US) projects reaching production.

***Figure 7: OPEC-11 apparent production vs call on OPEC 2000 – 2018***




*Source: IEA Oil Market Report (April 2018 and prior); Guinness estimates*

OPEC-12 met in November 2014, with the growing looseness in the physical market and a falling oil price (in the mid $70s at the time of the meeting) prompting a significant change in strategy to one that prioritised market share over price. As a result, there was no quota cut, as many had anticipated, and a confirmation that the 30m b/day target would be maintained. Post the November 2014 meeting, OPEC-14 (Indonesia and Gabon joined the group) not only maintained their quota but also raised production significantly, up over 18 months by 2.5m b/day. Iraq recovered its production by 1.2m b/day; Iran by 0.8m b/day post the lifting of sanctions relating to their nuclear programme; and Saudi by 0.9m b/day.

In November 2016, OPEC stepped back from their market share stance, announcing plans for the first production cut since 2008, opting for a new production limit of 32.5m b/day. The announcement represented a cut of 1.2m b/day (all numbers for OPEC-14 including Gabon). There was also an understanding that non-OPEC, including Russia, would cut production by 0.6m b/day, which would bring the total reduction to 1.8m b/day.

The November 2016 announcement amounted to a 5% cut for all members except for 1) Libya and Nigeria, recognising their unusually depressed levels of production due to unrest, and 2) Iran, recognising its journey back to normalised production post the lifting of sanctions in January 2016. Indonesia has been suspended from the group since, as a net importer of oil, it chose not to participate. The agreed cuts came into effect on 1 January 2017, and were initially designed to be kept in place for six months, but have since been extended to the end of 2018. Compliance with the cuts has so far been strong and, after been delayed initially by a variety of temporary factors, is now causing inventories to decline. Having originally been excluded from the cuts, Libya and Nigeria are now included in the quota system.

OPEC has showed clear intention to end restore the current production cuts in a manner that is consistent with maintaining a balanced market.

Clearly, OPEC economies have been under significant stress, which has been the near-term driver for the decision to cut production and bring oil prices higher. There is also the growing concern that the oil industry will be unable to supply enough in the future, leading to the next oil price spike, though that is probably a secondary concern to OPEC at present.

Saudi's actions at the head of OPEC appear designed to achieve an oil price that to some extent closes their fiscal deficit ($70-75/bl is needed to close the gap fully), whilst not spiking the oil price too high and over-stimulating non-OPEC supply. Longer term, we believe that Saudi seek a 'good' oil price, in excess of current levels to balance their fiscal needs, but they realise that patience is required to achieve that goal.

Overall, we reiterate two important criteria for Saudi:

1. Saudi is interested in the average price of oil that they get, they have a longer investment horizon than most other market participants
2. Saudi wants to maintain a balance between global oil supply and demand to maintain a price that is acceptable to both producers and consumers

Nothing in the market in recent years has changed our view that OPEC can put a floor under the price – as they did in 2008, 2006, 2001, 1998 – and again in 2016. Recent meetings and decisions indicate that OPEC have the resolve to continue in this manner.

**Supply looking forward**

The non-OPEC world has, since the 2008 financial crisis, grown its production more meaningfully than in the seven years before 2008. The growth was 0.9% p.a. from 2001-2008, increasing to 1.7% p.a. from 2008-2017.



Growth in the non-OPEC region over the last 5 years has been dominated by the successful development of shale oil and oil sands in North America (up around 4m b/day between 2010 and 2015), implying that the rest of non-OPEC region grew by only around 0.5m b/day over the period, despite the sustained high oil price until mid 2014.

After the strongest year for non-OPEC production in 2014 (+2.4m b/day) since 1978, non-OPEC growth in 2015 was also strong, at 1.4m b/day. Whilst the sub-$60 oil environment has caused significant deferral and cancellation of new developments, start-up projects that were sanctioned before the fall in the oil price are still coming to completion, creating this resilience in production. However, the effect of a low oil price impacted more in 2016, when non-OPEC supply fell by around 0.8m b/day. Non-OPEC supply recovered by 0.7m b/day in 2017, as US onshore production swung from decline back to growth.

The growth in US shale oil production, in particular from the Permian basin, raises the question of how much more there is to come and at what price. New oil production from these sources peaked in April 2015 at around 4m b/day, then declined by around 1.1m b/day, but has now passed the previous peak. Our assessment is that US shale oil is a capital intensive source of oil but one where real growth is viable, on average, at around $50 oil prices. In particular, there appears to be ample inventory in the Permian basin to allow growth well into the 2020s. In total, it could be comparable in size to the UK North Sea, i.e. it could grow by around a further 4m b/day over the next five years, but only if the price is sufficiently high to incentivise growth. The rate of development is heavily dependent on the cashflow available to producing companies, which tends to be recycled immediately into new wells, and the underlying cost of services to drill and fracture the wells. Naturally, cashflows available for reinvestment in a $60 world are far lower than in a $100 world, but with efficiency improvements and recent cost deflation, enough to see growth sustaining.

Offsetting US onshore shale oil growth, we expect to see non-OPEC supply outside the US start to decline in 2019, as the queue of large conventional project start-ups dries up. Since 2014, the number of project start-ups in this region has been sustained at a high level, despite lower oil prices, since projects that were sanctioned before the 2014 (when oil was $100+) have continued to come onstream. We believe 2019 marks a point, however, when the cancellation of projects that should have been sanctioned in 2015/16 starts to bite. A supply decline in the non-OPEC ex US region will increase the 'call' on US shale to balance the market.

Looking longer term, other opportunities to exploit unconventional oil likely exist internationally using techniques established in the US, notably in Argentina (Vaca Muerta), Russia (Bazhenov), China (Tarim and Sichuan) and Australia (Cooper). However, the US is far better understood geologically; the infrastructure in the US is already in place; service capacity in the US is high; and the interests of the landowner are aligned in the US with the E&P company. In most of the rest of the world, the reverse of each of these points is true, and as a result we see international shale being 10+ years behind North America.

**Demand looking forward**

The IEA estimate that 2017 oil demand growth was 1.6m b/day, and they expect a further increase of 1.5m b/day in 2018, taking demand to just over 99m b/day. Generally speaking, we have seen demand forecasts revised consistently higher since 2014, with the positive effect of lower oil prices continuing to surprise.

The IEA's global demand estimate for 2018 comprises an increase in non-OECD demand of 1.2m b/day and OECD demand growth of 0.3m b/day. The components of this non-OECD demand growth can be summarised as follows:

***Figure 8: Non-OECD oil demand***

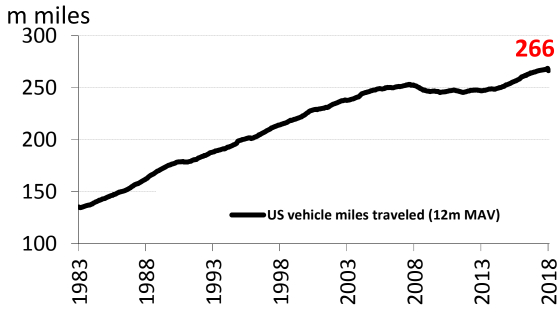
**Non-OECD demand (source: IEA monthly report)**

| *m b/day* | Demand | | | | | | | | Growth | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018e** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018e** |
| Asia | 20.3 | 21.4 | 22.1 | 22.8 | 24.0 | 24.8 | 25.8 | 26.7 | 1.1 | 0.7 | 0.7 | 1.2 | 0.8 | 1.0 | 0.9 |
| Middle East | 7.4 | 7.8 | 7.9 | 8.4 | 8.4 | 8.3 | 8.3 | 8.4 | 0.4 | 0.1 | 0.5 | 0.0 | -0.1 | 0.1 | 0.1 |
| Latin America | 6.2 | 6.4 | 6.7 | 6.8 | 6.7 | 6.6 | 6.6 | 6.6 | 0.2 | 0.3 | 0.1 | -0.1 | -0.1 | 0.0 | 0.0 |
| FSU | 4.4 | 4.6 | 4.7 | 4.66 | 4.6 | 4.8 | 4.7 | 4.8 | 0.2 | 0.1 | 0.0 | -0.1 | 0.2 | 0.0 | 0.1 |
| Africa | 3.5 | 3.8 | 3.9 | 3.8 | 4.1 | 4.3 | 4.3 | 4.4 | 0.3 | 0.1 | -0.1 | 0.3 | 0.2 | 0.0 | 0.1 |
| Europe | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total** | **42.5** | **44.7** | **46.0** | **47.2** | **48.4** | **49.4** | **50.5** | **51.6** | **2.2** | **1.3** | **1.2** | **1.2** | **1.1** | **1.0** | **1.2** |

*Source: IEA Oil Market Report (April 2018)*

Asia has settled down into a steady pattern of growth since 2010, and accounts for much of expected growth in 2017. Historically, China has been the most important component of this growth and continues to be a major component, although signs are emerging that India may also start to grow rapidly.

OECD demand in 2018 is forecast to be up by 0.3m b/day. In the US, the sharp fall in gasoline prices since 2014 has stimulated a reversal in improving fuel efficiency, as drivers switch back to purchasing larger vehicles, and a rise in total vehicle miles travelled, as shown in the chart opposite. Total vehicle miles travelled had stalled between 2007 and 2014, after two decades of growth, and are now growing again at a rate of around 1-2% per year.




The trajectory of global oil demand over the next few years will be a function of global GDP, pace of the ‘consumerisation’ of developing economies, and price. At current prices, the world oil bill as a percentage of GDP is around 2.5%, a likely stimulant of multi-year demand growth. If oil prices return to a higher range (say around $75/bbl, representing 3% of GDP), we probably return to the pattern established over the past 5 years, with a flat to shallow decline picture in the OECD more than offset by strong growth in the non-OECD area. The small decline in the OECD reflects improving oil efficiency over time, though this effect will be dampened by economic, population and vehicle growth. Within the non-OECD, population growth and rising oil use per capita will both play a significant part. Overall, we would not be surprised to see annual non-OECD demand growth of around 1.5m b/day by the end of the decade. This would represent a growth rate of 3% p.a., no greater than the growth rate over the last 15 years (3.2% p.a.).

We keep a close eye on developments in the ‘new energy’ vehicle fleet (electric vehicles; hybrids etc), but see nothing that makes a significant dent on the consumption of gasoline and diesel in the next few years. Sales of electric vehicles (pure electric and plug-in hybrid electrics) globally were around 1.2m in 2017, up from 0.8m in 2016. Sales of 1.6m electric vehicles represents around 1.5% of total light vehicle sales, and increases EV’s share of the world car fleet to 0.25%. We expect to see EV sales accelerate in 2018 to around 1.9m, or 2% of total global sales. Even applying an aggressive growth rate to EV sales, we see EVs comprising only around 0.6% of the global car fleet in 2020. Looking further ahead, we expect the penetration of EV’s to accelerate, causing global gasoline demand to peak at some point in the second half of the 2020s. However, owing to the weight of oil demand that comes from sources other than passenger vehicles (around 70%), which we expect to continue growing linked to GDP, we expect total oil demand not to peak until the mid 2030s.



**Conclusions about oil**

The table below summarises our view by showing our oil price forecasts for WTI and Brent in 2017 against their historic levels, and rises/falls in percentage terms that we have seen in the period from 2002 to 2016.

***Figure 9: Average WTI & Brent yearly prices, and changes***

| **Oil price (inflation adjusted)** | | | | | | | | | | | | | | | | | | *Est* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 12 month MAV | 1986-2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| WTI | 30 | 33 | 38 | 49 | 66 | 75 | 82 | 104 | 68 | 84 | 99 | 94 | 98 | 93 | 49 | 45 | 51 | 60 |
| Brent | 30 | 32 | 35 | 46 | 64 | 75 | 82 | 103 | 67 | 84 | 115 | 112 | 108 | 99 | 52 | 45 | 54 | 63 |
| **Brent/WTI (12m MAV)** | **30** | **33** | **37** | **48** | **65** | **75** | **82** | **104** | **68** | **84** | **107** | **103** | **103** | **96** | **51** | **45** | **53** | **62** |
| **Brent/WTI y-on-y change (%)** | | 8% | 12% | 30% | 37% | 15% | 9% | 26% | -35% | 24% | 27% | -4% | 0% | -7% | -47% | -11% | 17% | 17% |
| Brent/WTI (5yr MAV) | 30 | 25 | 32 | 37 | 42 | 51 | 61 | 75 | 79 | 82 | 89 | 93 | 93 | 99 | 92 | 80 | 69 | 61 |

We expect oil to trade in a $50-65/bl range in the near term, supported at the lower end by OPEC. If this price range persists, we expect North American unconventional supply to sustain growth. We believe that the 'call' on unconventional supply, however, is likely to grow into the end of the decade, as conventional non-OPEC supply declines.

The world oil bill at around $60/bl would represent 2.5% of 2018 Global GDP, 26% under the average of the 1970 – 2015 period (3.4%). A return to oil representing 3.4% of GDP implies an oil price of around $80/bl.

We believe that Saudi's long-term objective remains to maintain a 'good' oil price, similar to current spot levels, and that will allow the country to IPO Saudi Aramco successfully in the next year or so.

## Natural gas market

**US gas demand**

On the demand side, industrial gas demand and power generation gas demand, each about a quarter of total US gas demand, are key. Commercial and residential demand, which make up a further quarter, have been fairly constant on average over the last decade – although yearly fluctuations due to the coldness of winter weather can be marked.

Industrial demand (of which around 35% comes from petrochemicals) tends to trend up and down depending on the strength of the economy, the level of the US dollar and the differential between US and international gas prices. Between 2000 and 2009 industrial demand was in steady decline, falling from 22.2 Bcf/day to 16.9 Bcf/day. Since 2009 the lower gas price (particularly when compared to other global gas prices) and recovery from recession has seen demand rebound, up in 2017 to around 21.4 Bcf/day.

Electricity gas demand (i.e. power generation) is affected by weather, in particular warm summers which drive demand for air conditioning, but the underlying trend depends on GDP growth and the proportion of incremental new power generation each year that goes to natural gas versus the alternatives of coal, nuclear and renewables. Gas has been taking market share in this sector: in 2017, 33% of electricity generation was powered by gas, up from 22% in 2007. The big loser here is coal which has consistently given up market share over the past 10 years.

| Bcf/day | 2007 | 2008 | *2009* | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018E |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **US natural gas demand:** | | | | | | | | | | | | |
| Residential/commercial | 21.2 | 22.0 | 21.6 | 21.6 | 21.6 | 19.2 | 22.4 | 23.4 | 21.4 | 20.5 | 20.9 | 21.7 |
| Power generation | 18.7 | 18.2 | 18.8 | 20.2 | 20.8 | 24.9 | 22.3 | 22.3 | 26.5 | 27.3 | 25.3 | 26.9 |
| Industrial | 18.2 | 18.2 | 16.9 | 18.5 | 19.0 | 19.7 | 20.3 | 20.9 | 20.6 | 21.1 | 21.6 | 22.2 |
| Pipeline exports (Canada & Mexico) | 2.1 | 2.5 | 2.8 | 2.9 | 4.1 | 4.4 | 4.4 | 4.1 | 4.9 | 6.3 | 6.2 | 7.0 |
| LNG exports | - | - | - | - | - | - | - | - | 0.1 | 1.0 | 2.6 | 3.4 |
| Pipeline/plant/other | 5.2 | 5.3 | 5.5 | 5.6 | 5.8 | 6.1 | 6.7 | 6.3 | 6.5 | 6.4 | 6.5 | 6.4 |
| **Total demand** | **65.4** | **66.2** | **65.6** | **68.8** | **71.3** | **74.3** | **76.1** | **77.0** | **80.0** | **82.6** | **83.1** | **87.6** |
| **Demand growth** | **4.0** | **0.8** | **- 0.6** | **3.2** | **2.5** | **3.0** | **1.8** | **0.9** | **3.0** | **2.6** | **0.5** | **4.5** |

*Source: EIA; Simmons; Guinness estimates*

Total gas demand in 2017 (including Canadian, Mexican and LNG exports) is expected to be around 83.1 Bcf/day, up by just 0.5 Bcf/day (0.6%) versus 2016 but 5 Bcf/day (6.5%) higher than the 5 year average. LNG exports have risen significantly this year (+2 Bcf/day), but this has been offset by a 2 Bcf/day decline in demand from power generation, owing to normalising weather and gas to coal utility switching, prompted by prices back above $3/mcf.

**Demand outlook**

We expect demand 2018, assuming prices remain around $3/mcf, to exhibit strong growth of around 3 Bcf/day. We see several sources of higher demand driving this growth, including rising pipeline exports to Mexico, rising demand from power generation (gas taking share back from coal) and slightly higher LNG exports.

Looking out further, the low US gas price has stimulated various initiatives that are likely have an increasingly material impact on demand as we move through to the end of the decade. The most significant is the group of LNG export terminals in the US, many of which are still in the construction stages but will come online in 2019 and 2020. The table below shows the scheduled start-up of terminals, with 5.7 Bcf/day of capacity coming in 2019 – inevitably, some of this will be delayed into 2020.

| Terminal | Location | 2015 | 2016 | 2017 | 2018E | 2019E | 2020E |
|---|---|---|---|---|---|---|---|
| Cameron 1-2 | LA | | | | | 1.2 | |
| Cameron 3 | LA | | | | | 0.6 | |
| Corpus Christi 1-2 | TX | | | | | 1.5 | |
| Cove Point 1 | MD | | | 0.8 | | | |
| Elba Island 1-6 | GA | | | | 0.3 | | |
| Elba Island 7-10 | GA | | | | | 0.2 | |
| Sabine Pass 1-2 | LA | | | | | | |
| Sabine Pass 3-4 | LA | 0.1 | 1.0 | 1.2 | | | |
| Sabine Pass 5 | LA | | | | | 0.7 | |
| Freeport 1 | TX | | | | | 0.5 | |
| Freeport 2-3 | TX | | | | | 1.0 | |
| **Incremental LNG exports** | | **0.1** | **1.0** | **2.0** | **0.3** | **5.7** | **0.0** |
| **Total US LNG exports** | | **0.1** | **1.1** | **3.1** | **3.4** | **9.1** | **9.1** |

*Source: EIA; Simmons*

Industrial demand will also grow thanks to the increased use of gas in the oil refining process and the construction of new petrochemical plants: Dow Chemical and Chevron Phillips have started up a large new Gulf Coast facility this year, the first new cracker to be built in the US since 2001.

We also believe that gas will continue to take the majority of incremental power generation growth in the US and continue to take market share from coal. Coal fired power generation closures have been a feature of 2015 as pollution standards come into force in an effort to reduce mercury and acid gases emissions, which likely accelerates the switch to gas.  Our working assumption is for gas fired power generation to grow 0.8-1.2 Bcf/day per year, although this will be affected by actual gas prices.

**US gas supply**

Overall, whilst gas demand in the US has been strong over the past five years, it has been overshadowed by a rise in onshore supply, pulling the gas price lower.

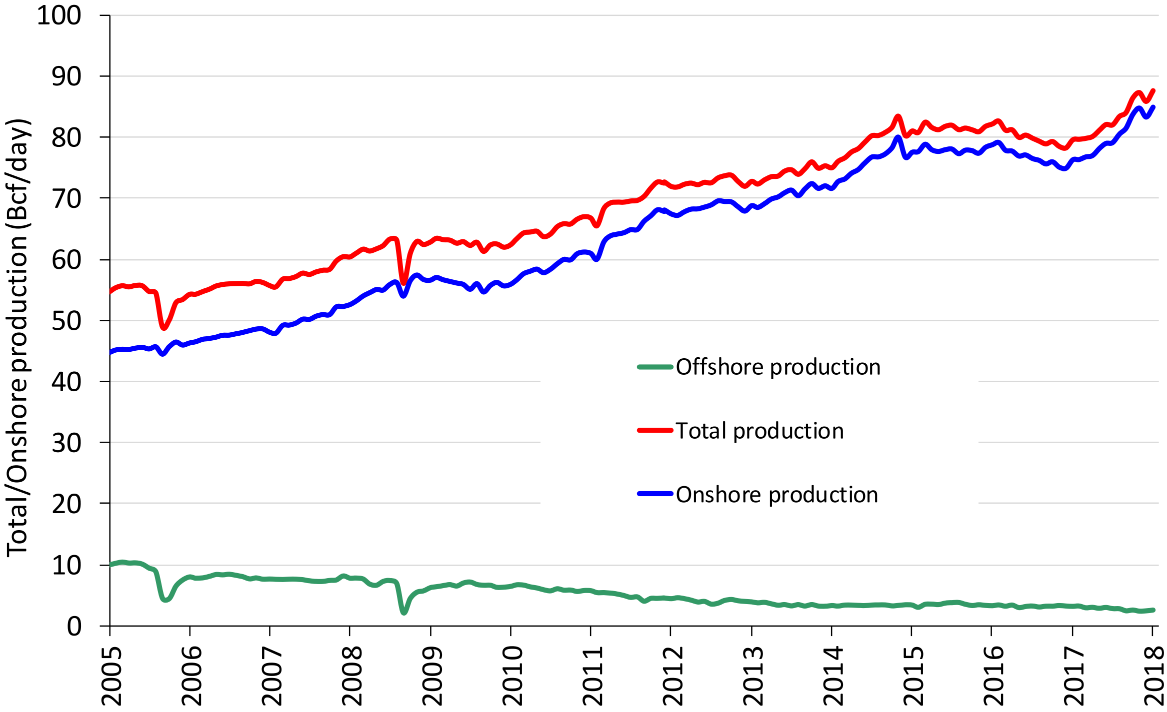
The supply side fundamentals for natural gas in the US are driven by 3 main moving parts: onshore and offshore domestic production, and pipeline imports of gas from Canada. Of these, onshore supply is the biggest component, making up over 85% of total supply.

| Bcf/day | 2007 | 2008 | *2009* | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018E |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **US natural gas supply:** | | | | | | | | | | | | |
| US onshore | 45.1 | 48.8 | 49.8 | 52.2 | 57.7 | 61.5 | 62.7 | 67.5 | 70.6 | 69.4 | 70.4 | 77.3 |
| US offshore (Gulf of Mexico) | 7.7 | 6.3 | 6.7 | 6.2 | 5.0 | 4.2 | 3.6 | 3.4 | 3.6 | 3.4 | 3.2 | 3.2 |
| Pipeline imports (Canada) | 10.4 | 9.8 | 9.0 | 9.0 | 8.5 | 8.0 | 7.5 | 7.1 | 7.1 | 8.0 | 8.0 | 8.0 |
| LNG imports & other | 2.3 | 1.2 | 1.4 | 1.4 | 1.0 | 0.8 | 0.6 | 0.5 | 0.5 | 0.4 | 0.3 | 0.4 |
| **Total supply** | **65.5** | **66.1** | **66.9** | **68.8** | **72.2** | **74.5** | **74.4** | **78.5** | **81.8** | **81.2** | **81.9** | **88.9** |
| **Supply growth** | **3.2** | **0.6** | **0.8** | **1.9** | **3.4** | **2.3** | **- 0.1** | **4.1** | **3.3** | **- 0.6** | **0.7** | **7.0** |

*Source: EIA; Simmons; Guinness estimates*

Since the middle of 2008 the weaker gas price in the US reflects growing onshore US production driven by rising shale gas and associated gas production (a by-product of growing onshore US oil production). Interestingly, the overall rise in onshore production has come despite a collapse in the number of rigs drilling for gas, which has dropped from a 1,606 peak in September 2008 to only 81 in September 2016 and now 194 at the end of February 2018. However, offsetting the fall, the average productivity per rig has risen dramatically as producers focus their attention on the most prolific shale basins, whilst associated gas from oil production has grown handsomely. Onshore gas supply (gross, before processing) is now at 84.9 Bcf/day, 27.5 Bcf/day (48%) above the 57.4 Bcf/d peak in November 2008 before the rig count collapsed.

***Figure 10: US natural gross gas production 2005 – 2018 (Lower 48 States)***




*Source: EIA 914 data (February 2018 published in May 2018)*

**Supply outlook**

The outlook for gas production in the US depends on three key factors: the rise of associated gas (gas produced from wells classified as oil wells); expansion of the newer shale basins, principally the Marcellus/Utica, and the decline profile of legacy gas fields.

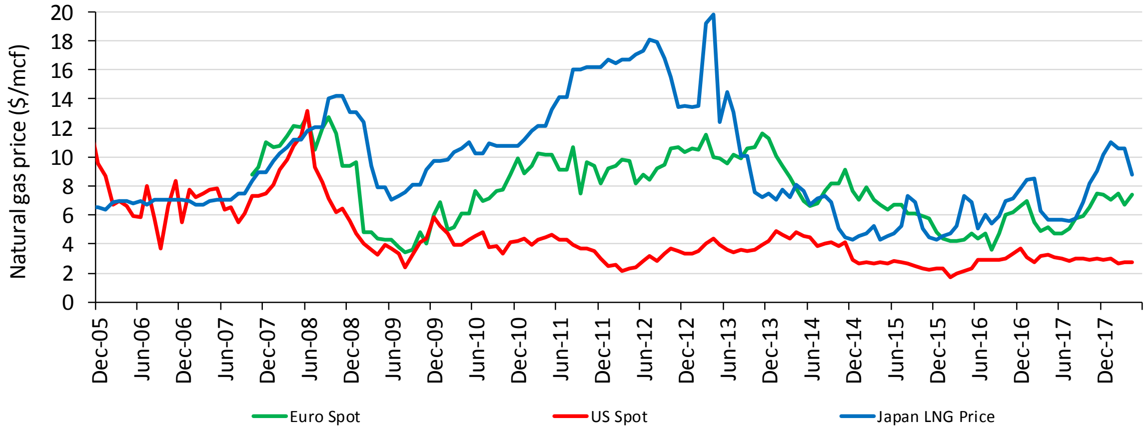
Associated gas production declined in 2016 with the fall of shale oil production, but as US oil supply now growing again, so associated gas production is also picking up. Generally, we expect to see rates of around 2-3 Bcf/day of associated gas per 1m b/day of oil production.

The Marcellus/Utica region, which includes the largest producing gas field in the US and the surrounding region, reached production of around 17 Bcf/day in 2016, though growth has recently slowed. Further growth is likely over the next couple of years, but only if local price differentials improve from the extreme levels seen in 2016. Then there is an expected decline in legacy gas fields, particularly if the gas drilling rig count stays low.

Overall, if the price remains in the $2.50-$3.50/mcf range, we expect a significant jump in onshore gas supply in 2018, up by around 5 Bcf/day versus this year.

**Outlook for US LNG exports – global gas arbitrage**

The prospects for US LNG exports depend on the differentials to European and Asian gas prices, and whether the economic incentive exists to carry out the trade. The UK national balancing point (NBP) gas price – which serves as a proxy to the European traded gas price – remains at a premium to the US gas price (c.$7/mcf versus c.$3/mcf). Asian spot LNG prices fell sharply down to around $4.50/mcf at the start of 2016 but have since recovered to around $8/mcf as Chinese gas demand strengthens. The implied economics are tight at these levels into Europe, better into Asia, but sufficient to expect exports to proceed.



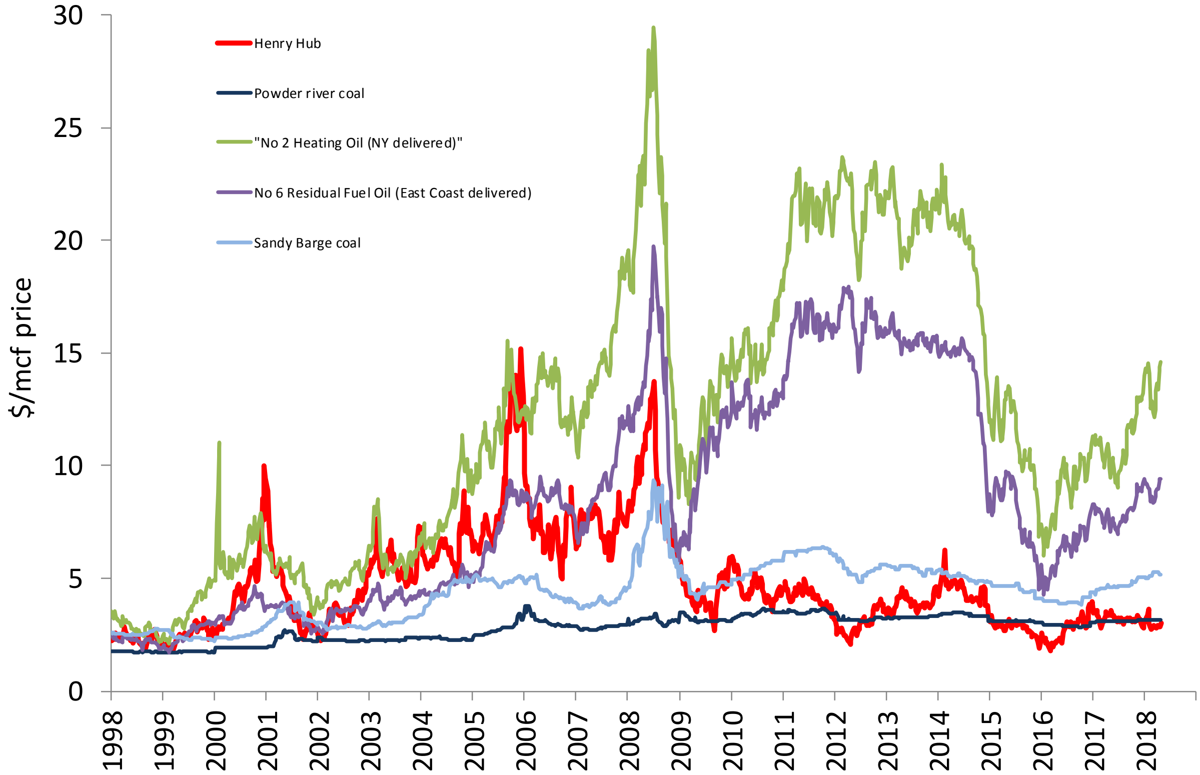

**Relationship with oil and coal**

The oil/gas price ratio ($ per bbl WTI/$ per mcf Henry Hub) of around 25x at the end of April 2018 continues well outside the long-term ratio of 6-9x.

The following chart of the front month US natural gas price against heating oil (No 2), residual fuel oil (No 6) and coal (Sandy Barge adjusted for transport and environmental costs) seeks to illustrate how coal and residual fuel oil switching provide a floor and heating oil a ceiling to the natural gas price. When the gas price has traded below the coal price support level (2012 and 2016), resulting coal to gas switching for power generation was significant.

***Figure 11: Natural gas versus substitutes (fuel oil and coal)***

Henry Hub vs residual fuel oil, heating oil, Sandy Barge (adjusted) and Powder River coal (adjusted)




*Source: Bloomberg LP (May 2018)*

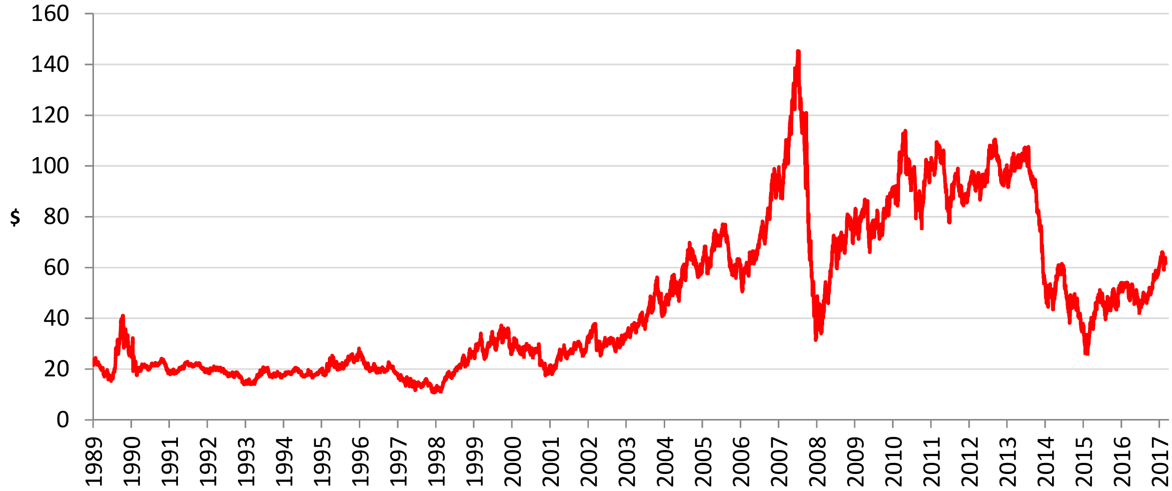
**Conclusions about US natural gas**

| Bcf/day | 2007 | 2008 | *2009* | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018E |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Total demand** | **65.4** | **66.2** | **65.6** | **68.8** | **71.3** | **74.3** | **76.1** | **77.0** | **80.0** | **82.6** | **83.1** | **87.6** |
| **Demand growth** | **4.0** | **0.8** | **-0.6** | **3.2** | **2.5** | **3.0** | **1.8** | **0.9** | **3.0** | **2.6** | **0.5** | **4.5** |
| **Total supply** | **65.5** | **66.1** | **66.9** | **68.8** | **72.2** | **74.5** | **74.4** | **78.5** | **81.8** | **81.2** | **81.9** | **88.9** |
| **Supply growth** | **3.2** | **0.6** | **0.8** | **1.9** | **3.4** | **2.3** | **-0.1** | **4.1** | **3.3** | **-0.6** | **0.7** | **7.0** |
| **(Supply)/demand balance** | **-0.1** | **0.1** | **-1.3** | **-** | **-0.9** | **-0.2** | **1.7** | **-1.5** | **-1.8** | **1.4** | **1.2** | **-1.3** |

The US natural gas price bottomed in 2012 and a tepid recovery since then has been muted by continued strength in gas supply, particularly from the Marcellus/Utica and from gas produced as a by-product of shale oil. Average 2016 natural gas prices (at $2.55) were around 50% higher the April 2012 low, though we suspect that the (full cycle) marginal cost of supply remains above $3.50. We do not believe the excess in production over demand can continue indefinitely with natural gas trading at this level: a combination of reduced capital spending by the producing companies and growing natural gas demand stimulated by the low gas price will create a new market equilibrium. As this all happens we expect the price to stabilise in the $2.75 – $3.25/mcf range. It may be held at this level for a period until demand grows further, and longer term we expect the price to normalise to the top end of this range.

## 3. APPENDIX Oil and gas markets historical context

***Figure 12: Oil price (WTI $) last 26 years.***




*Source: Bloomberg LP*

For the oil market, the period since the Iraq Kuwait war (1990/91) can be divided into two distinct periods: the first 9-year period was broadly characterized by decline. The oil price steadily weakened 1991 - 1993, rallied between 1994 –1996, and then sold off sharply, to test 20 year lows in late 1998. This latter decline was partly induced by a sharp contraction in demand growth from Asia, associated with the Asian crisis, partly by a rapid recovery in Iraq exports after the UN Oil for food deal, and partly by a perceived lack of discipline at OPEC in coping with these developments.

The last 13 years, by contrast, have seen a much stronger price and upward trend. There was a very strong rally between 1999 and 2000 as OPEC implemented 4m b/day of production cuts. It was followed by a period of weakness caused by the rollback of these cuts, coinciding with the world economic slowdown, which reduced demand growth and a recovery in Russian exports from depressed levels in the mid 90's that increased supply. OPEC responded rapidly to this during 2001 and reintroduced production cuts that stabilized the market relatively quickly by the end of 2001.

Then, in late 2002 early 2003, war in Iraq and a general strike in Venezuela caused the price to spike upward. This was quickly followed by a sharp sell-off due to the swift capture of Iraq's Southern oil fields by Allied Forces and expectation that they would win easily. Then higher prices were generated when the anticipated recovery in Iraq production was slow to materialise. This was in mid to end 2003 followed by a much more normal phase with positive factors (China demand; Venezuelan production difficulties; strong world economy) balanced against negative ones (Iraq back to 2.5 m b/day; 2Q seasonal demand weakness) with stock levels and speculative activity needing to be monitored closely. OPEC's management skills appeared likely to be the critical determinant in this environment.

By mid-2004 the market had become unsettled by the deteriorating security situation in Iraq and Saudi Arabia and increasingly impressed by the regular upgrades in IEA forecasts of near record world oil demand growth in 2004 caused by a triple demand shock from strong demand simultaneously from China; the developed world (esp. USA) and Asia ex China. Higher production by OPEC has been one response and there was for a period some worry that this, if not curbed, together with demand and supply responses to higher prices, would cause an oil price sell off. Offsetting this has been an opposite worry that non-OPEC production could be within a decade of peaking; a growing view that OPEC would defend $50 oil vigorously; upwards pressure on inventory levels from a move from JIT (just in time) to JIC (just in case); and pressure on futures markets from commodity fund investors.

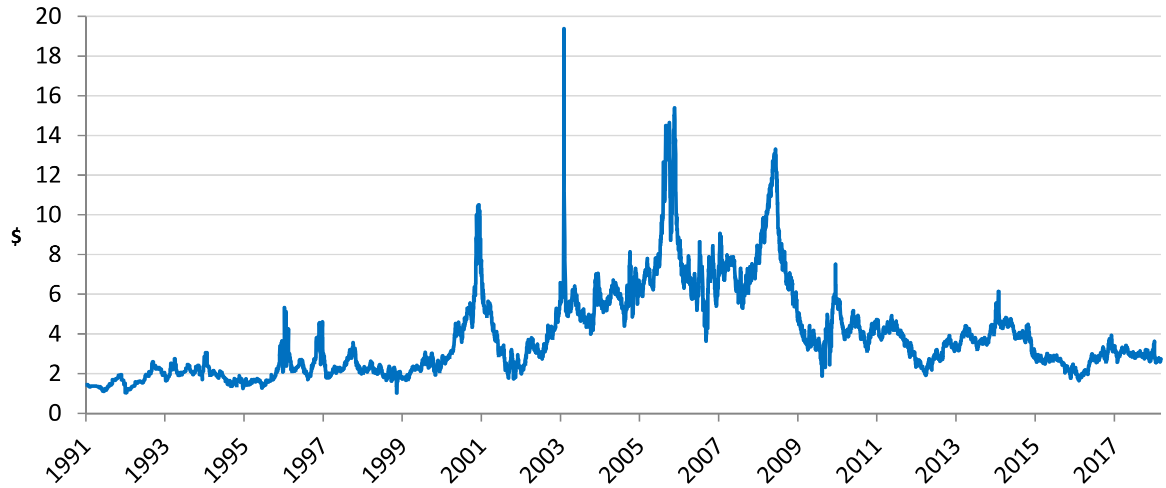
After 2005 we saw a further strong run-up in the oil price. Hurricanes Katrina and Rita, which devastated New Orleans, caused oil to spike up to $70 in August 2005, and it spiked up again in July 2006 to $78 after a three week conflict between Israel and Lebanon threatened supply from the Middle East. OPEC implemented cuts in late 2006 and early 2007 of 1.7 million barrels per day to defend $50 oil and with non-OPEC supply growth at best anaemic demonstrated that it could to act a price-setter in the market at least so far as putting a floor under it.

Continued expectations of a supply crunch by the end of the decade, coupled with increased speculative activity in oil markets, contributed to the oil price surging past $90 in the final months of 2007 and as high as $147 by the middle of 2008. This spike was brought to an abrupt end by the collapse of Lehman Brothers and the financial crisis and recession that followed, all of which contributed to the oil price falling back by early 2009 to just above $30. OPEC's responded decisively and reduced output, helping the price to recover in 2009 and stabilise in the $70-95 range where it remained for two years.

Prices during 2011-2014 moved higher, averaging around $100, though WTI generally traded lower than Brent oil benchmarks due to US domestic oversupply affecting WTI. During this period, US unconventional oil supply grew strongly, but was offset by the pressures of rising non-OECD demand and supply tensions in the Middle East/North Africa.

Most recently, since the end of 2014, Brent and WTI have dropped well below these trading ranges, as OPEC made clear their intention not to support the price, leaving the market oversupplied. Oil prices found a bottom in 2016 as a result of OPEC cutting production again, but remains capped for the timebing by US onshore shale supply.

***Figure 13: North American gas price last 25 years (Henry Hub $/Mcf)***




*Source: Bloomberg LP*

With regard to the US natural gas market, the price traded between $1.50 and $3/Mcf for the period 1991 - 1999. The 2000s were a more volatile period for the gas price, with several spikes over $8/mcf, but each lasting less than 12 months. On each occasion, the price spike induced a spurt of drilling which brought the price back down. Excepting these spikes, from 2004 to 2008, the price generally traded in the $5-8 range. Since 2008, the price has averaged below $4 as progress achieved in 2007-8 in developing shale plays boosted supply while the 2008-09 recession cut demand. Demand has been recovering since 2009 but this has been outpaced by continued growth in onshore production, driven by the prolific Marcellus/Utica field and associated gas as a by-product of shale oil production.

North American gas prices are important to many E&P companies. In the short-term, they do not necessarily move in line with the oil price, as the gas market is essentially a local one. (In theory 6 Mcf of gas is equivalent to 1 barrel of oil so $60 per barrel equals $10/Mcf gas). It remains a regional market more than a global market because the infrastructure to export LNG from North America is not yet in place.

## IMPORTANT INFORMATION AND RISK FACTORS

**Issued by Guinness Asset Management Limited**, authorised and regulated by the Financial Conduct Authority.

This report is primarily designed to inform you about recent developments in the energy markets invested in by the Guinness Global Energy Fund. It may also provide information about the Fund's portfolio, including recent activity and performance. It contains facts relating to the energy market and our own interpretation. Any investment decision should take account of the subjectivity of the comments contained in the report.

This document is provided for information only and all the information contained in it is believed to be reliable but may be inaccurate or incomplete; any opinions stated are honestly held at the time of writing, but are not guaranteed. The contents of the document should not therefore be relied upon. It should not be taken as a recommendation to make an investment in the Fund or to buy or sell individual securities, nor does it constitute an offer for sale.

**Risk**
The Guinness Global Energy Fund is an equity fund. Investors should be willing and able to assume the risks of equity investing. The value of an investment and the income from it can fall as well as rise as a result of market and currency movement, and you may not get back the amount originally invested. The Fund invests only in companies involved in the energy sector; it is therefore susceptible to the performance of that one sector, and can be volatile. Details on the risk factors are included in the Fund's documentation, available on our website.

**Documentation**
The documentation needed to make an investment, including the Prospectus, the Key Investor Information Document (KIID) and the Application Form, is available from the website www.guinnessfunds.com , or free of charge from:

- the Manager: Link Fund Manager Solutions (Ireland) Ltd, 2 Grand Canal Square, Grand Canal Harbour, Dublin 2, Ireland; or,
- the Promoter and Investment Manager: Guinness Asset Management Ltd, 14 Queen Anne's Gate, London SW1H 9AA.

**Residency**
In countries where the Fund is not registered for sale or in any other circumstances where its distribution is not authorised or is unlawful, the Fund should not be distributed to resident Retail Clients. **NOTE: THIS INVESTMENT IS NOT FOR SALE TO U.S. PERSONS.**

**Structure & regulation**
The Fund is a sub-fund of Guinness Asset Management Funds PLC (the "Company"), an open-ended umbrella-type investment company, incorporated in Ireland and authorised and supervised by the Central Bank of Ireland, which operates under EU legislation. If you are in any doubt about the suitability of investing in this Fund, please consult your investment or other professional adviser.

**Switzerland**
The prospectus and KIID for Switzerland, the articles of association, and the annual and semi-annual reports can be obtained free of charge from the representative in Switzerland, Carnegie Fund Services S.A., 11, rue du Général-Dufour, 1204 Geneva, Switzerland, Tel. +41 22 705 11 77, www.carnegie-fund-services.ch. The paying agent is Banque Cantonale de Genève, 17 Quai de l'Ile, 1204 Geneva, Switzerland.

**Singapore**
The Fund is not authorised or recognised by the Monetary Authority of Singapore ("MAS") and shares are not allowed to be offered to the retail public. The Fund is registered with the MAS as a Restricted Foreign Scheme. Shares of the Fund may only be offered to institutional and accredited investors (as defined in the Securities and Futures Act (Cap.289)) ('SFA') and this material is limited to the investors in those categories

**Telephone calls** will be recorded and monitored.