THE GUINNESS GLOBAL ENERGY REPORT

Developments and trends for investors in the global energy sector | October 2017

GUINNESS GLOBAL ENERGY FUND

Fund size: $318m (30.9.17)

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 Tim Guinness, Will Riley and Jonathan Waghorn. 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 SEPTEMBER

OIL

Brent and WTI up strongly on better fundamentals

Brent and WTI both up strong over the month; WTI broke through $50/bl and closed at $51.7/bl while Brent retrenched from its near $60/bl highs to close the month at $57.5/bl. Onshore US oil production growth was only 54k b/d in July while OPEC maintained good production compliance and exports continued to fall. OECD oil and product stocks were flat in both July and August, versus seasonal average builds.

NATURAL GAS

US gas prices unchanged; market slightly undersupplied

Henry Hub prices were broadly flat in September at just over $3/mcf. Weather adjusted, the US gas market remained undersupplied albeit less than in previous weeks, allowing gas inventories to growing broadly in line with seasonal averages. Exports of LNG and natural gas vis pipeline to Mexico continue to grow but new supply remains available.

EQUITIES

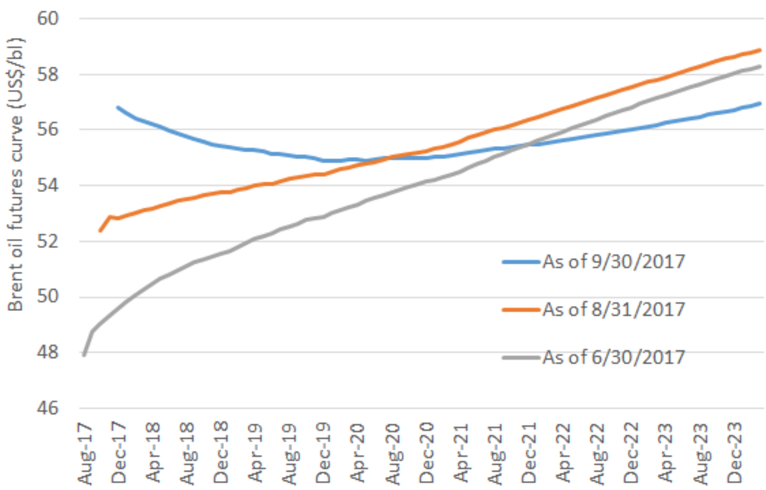
Energy outperforms the broad market

The MSCI World Energy Index rose in September by 9.0%, outperforming the MSCI World Index which rose by 2.27% (all in US dollar terms). Since the start of the year, the MSCI Energy Index is down by -0.87%, which compares to the MSCI World up by 16.53%.

CHART OF THE MONTH

Brent oil forward curve moves into backwardation

Brent crude oil prices were up 20.1% over the quarter but, more importantly, the Brent oil forward curve also moved from contango into backwardation late in the quarter. We view the structure of the forward curve as being just as important as the level of spot oil price and note that this is the first time since August 2014 that the Brent oil forward curve has been in backwardation. The backwardated curve (front month price being higher than 12 month forward price) indicates tight near term supply and demand fundamentals in the Brent oil market



Source: Bloomberg; Guinness Asset Management

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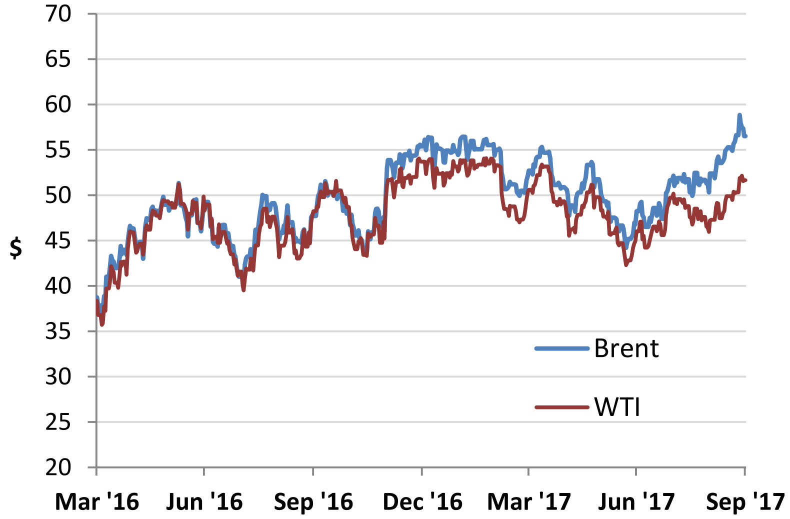
1. SEPTEMBER IN REVIEW

i) Oil market

Figure 1: Oil price (WTI and Brent $/barrel) 18 months March 31 2016 to September 30 2017



Source: Bloomberg LP

The West Texas Intermediate (WTI) oil price started September at $47.2/bl and strenghtened steadily over the month to close close to its highs at $51.7/bl. WTI has averaged $49.4/bl so far in 2017, having averaged $43.4 in 2016, $48.7 in 2015 and $93.1 in 2014.

Brent oil traded more strongly, opening September at $52.4/bl, trading higher all month until reaching just over $59/bl on 25th Septmber and then closing the month slightly lower at $57.5/bl. Brent has averaged $52.6/bl so far in 2017. The gap between the WTI and Brent benchmark oil prices continued to remain wide during the month as a result of Tropical Harvey, ending September at just under $6/bl, compared to the pre-Harvey level of around $2/bl seen prior in the year.

Factors which Strengthened WTI oil prices in September:

- **Continued strong oil demand growth in 2017 and robust expectations of further growth**
  IEA expectations of 2017 world oil demand have increased from 1.3mn b/d at the start of 2017 to 1.6mn b/d in the most recent IEA Oil Monthly report. The increase in demand is split 0.4mn b/d from OECD countries and 1.2mn b/d for non-OECD countries, indicating continued strong demand trends for both regions. We noted with interest that the IEA is also forecasting the world oil demand will exceed 100mn b/d on average in 3Q 2018. The effect of low oil prices has been that world oil demand has grown greater than expectation.

- **Weaker than expected US onshore production growth and E&P production efficiencies**
  At the start of October, the EIA reported that US onshore oil production grew by 52k b/day during July 2017, bringing year over year growth for the US onshore system to 370k b/d. This is the second month in a row that US onshore production data has been lower than expectation.We expect the US onshore production in 2017 to average around 300,000-400,000 b/day higher than 2016.

- **Sustained high levels of OPEC compliance and hopes that current quotas could be extended**
  As of the end of August, we recorded compliance form OPEC (ex Libya and Nigeria) with its stated production quotas of around 85%. While production compliance has slipped somewhat in recent months, tanker tracking data indicated that exports from OPEC countries (and Saudi Arabia especially) continued to fall. Amid the improved export compliance data, there were an increasing number of comments form OPEC members that the group weas considering extending production quotas beyond March 2018 if needed.

- **Sustained reduction in global and US oil and oil product inventories**
  US oil and product inventories fell by 19.1m barrels over the four weeks reported in September, which compares to a 5-year average decline of 1.6m barrels. This implies that inventories tightened by around 0.6m b/day versus norms, a useful step towards normalising inventories. OECD oil and product inventories for August (reported in September) were flat on the levels reported for both June and July versus typical seasonal builds of around 19mn and 15mn barrels in those months. Total OECD inventories remain elevated, but we expect them to continue to decline over the remainder of 2017.

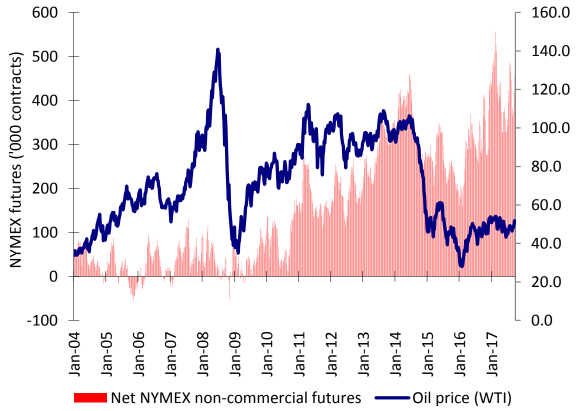
Factors which weakened WTI and Brent oil prices in September:

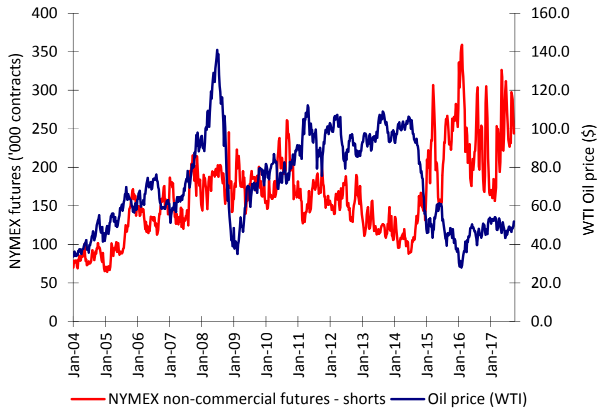
- **Technical pull back at the end of September**
  On September 25th, a positive technical indicator occurred in the Brent crude oil markets. The 50 day moving average of Brent crude oil prices rose through the 200 day moving average of Brent crude oil prices, leading to technical buying and causing Brent oil to be up 12.7% on a month to date basis. Brent crude oil prices corrected in the subsequent days and we believe that the correction was driven by predominantly technical rather than fundamental factors.

Speculative and investment flows

The New York Mercantile Exchange (NYMEX) net non-commercial crude oil futures open position (WTI) grew in September, ending the month at 454,000 contracts long versus 366,000 contracts long at the end of August. Typically there is a positive correlation between the movement in net position and movement in the oil price. The gross short position declined from 297,000 contracts to 244,000 contracts. We regard this gross short position as high but no longer extreme.

Figure 2: NYMEX Non-commercial net and short futures contracts: WTI January 2004 – September 2017



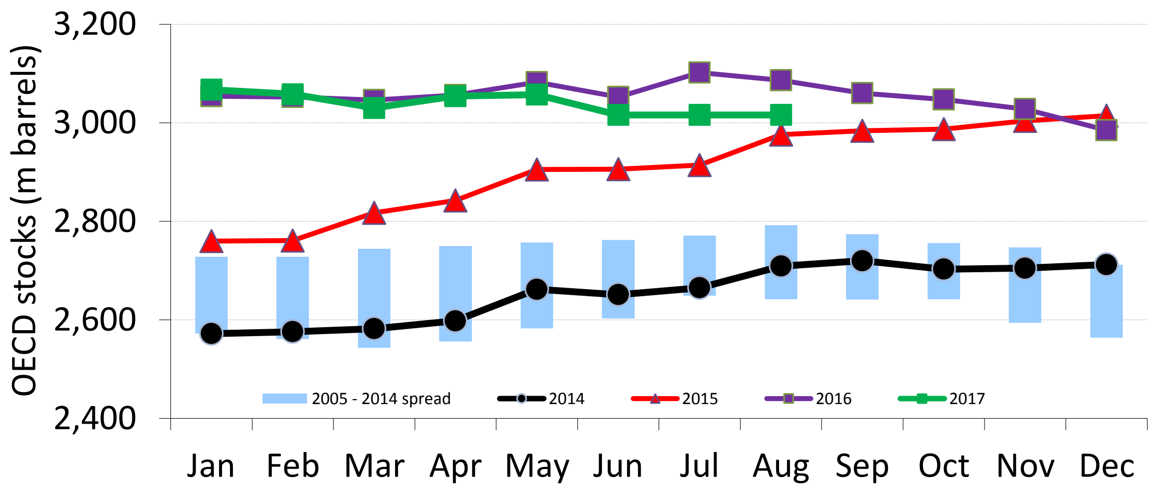


Source: Bloomberg LP/NYMEX/ICE (2017)

OECD stocks

OECD total product and crude inventories at the end of August (the latest data point available) were estimated by the IEA to be 3,016m barrels, flat versus both July and June's levels. This compares to a 10-year average build for July of 19m barrels and August of 15m bls. Having been in decline over the second half of 2016, inventories loosened at the start of 2017, as a flush of pre-OPEC cut production reached the market, but are now tightening again. Inventories remain considerably above the top of the 10 year historic range, and we expect them to continue to tighten over the remainder of 2017.

Figure 3: OECD total product and crude inventories, monthly, 2004 to 2017



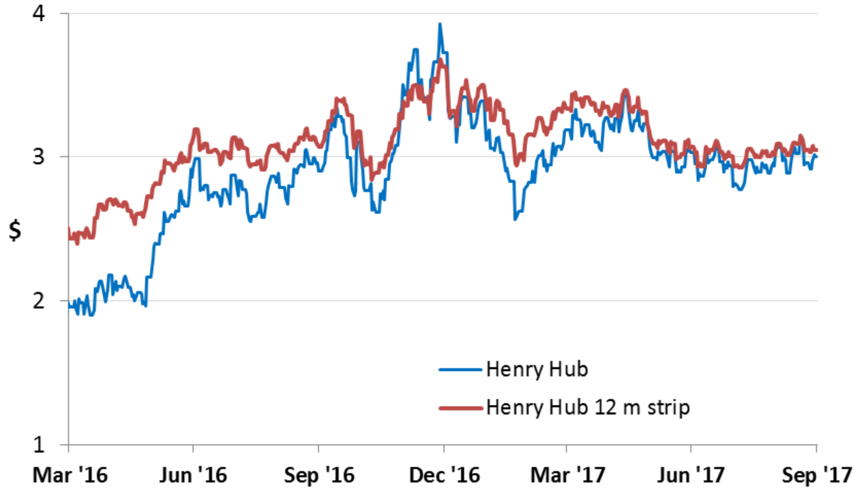
Source: IEA Oil Market Reports (September 2017 and older)

ii) Natural gas market

The US natural gas price (Henry Hub front month) opened September at $3.04/mcf (1,000 cubic feet). The price stayed very much range bound during the month, closing at $3.01/mcf. The spot gas price has averaged $3.00/mcf so far in 2017, which compares to an average gas price of $2.55/mcf in 2016, $2.61/mcf in 2015 and $4.26/mcf in 2014 (assisted by a very cold 2013/14 US winter). The price averaged $3.72/mcf over the preceding four years (2010-2013).

The 12-month gas strip price (a simple average of settlement prices for the next 12 months' futures prices) also remained broadly flat over the month, opening at $3.06/mcf and closing at $3.05/mcf. The strip price averaged $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) March 31 2016 to September 30 2017



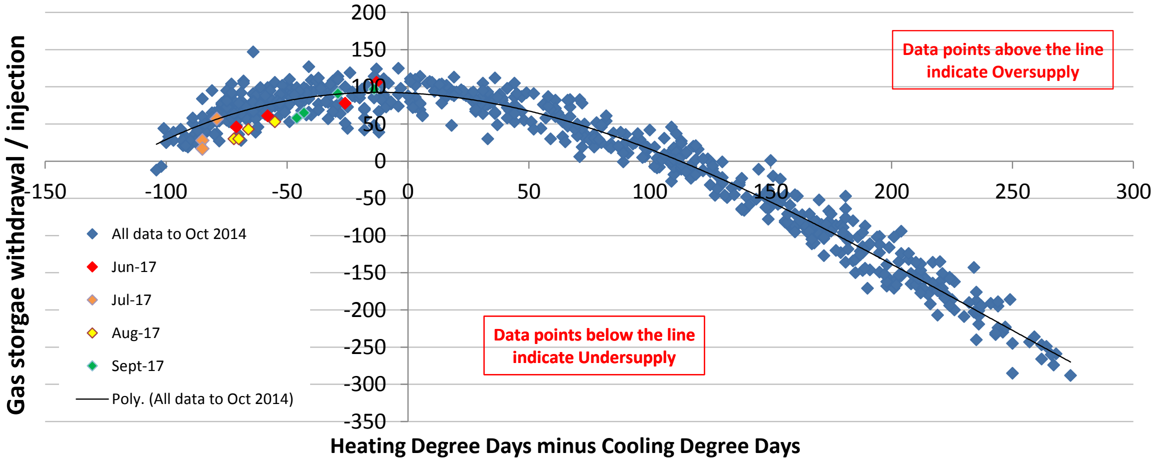
Source: Bloomberg LP

Factors which strengthened the US gas price in September included:

- **Impact of Tropical Storm Harvey**
  We believe Tropical Storm Harvey caused around 1.6 Bcf/day of natural gas production to be shut-in, representing about 2% of US gas supply. Around half of this was offshore Gulf of Mexico production (c.26% of GoM's 3.2 Bcf/day) and half onshore Eagleford production. The impact of Harvey on the US gas market has been far less than Hurricane Katrina caused in 2005. At that time, the Gulf of Mexico produced over 10 Bcf/day of gas, versus 3 Bcf/day (normally) at present.

- **Structurally undersupplied market**
  Adjusting for the impact of weather in September, the most recent injections of gas into storage suggest the market is, on average, around 1 bcf/day undersupplied (as indicated by the green dots on the graph below). The gas market shifted into structural undersupply in late 2015, but that has been trumped over the last 18 months by two successive warm winters which have lowered demand.

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



Source: Bloomberg LP; Guinness Asset Management

Factors which weakened the US gas price in September included:

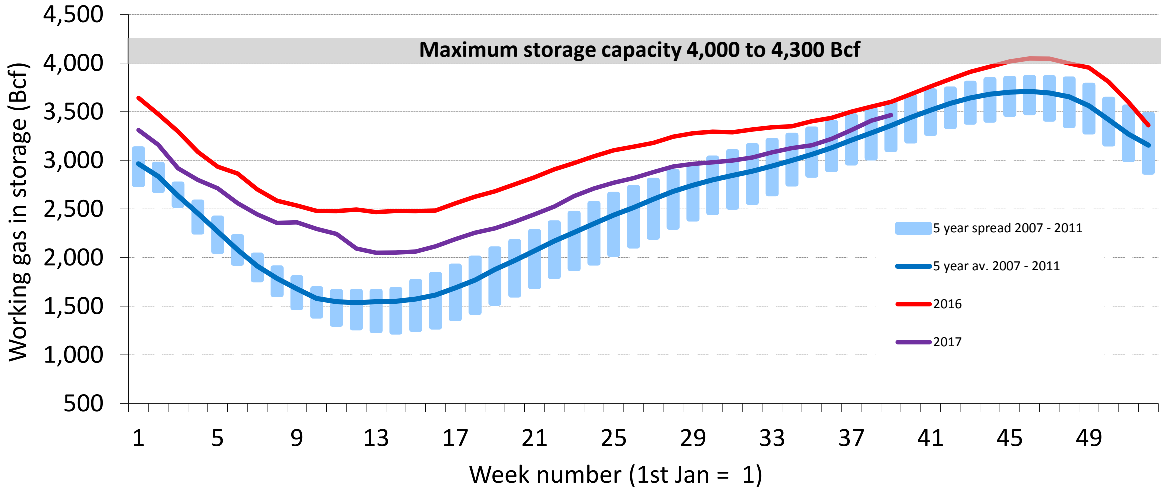
- **Stronger US onshore natural gas production**

Onshore US natural gas production averaged 79.1 Bcf/day in July 2017 (the latest available data point), up by 1.0 Bcf/day on the level reported for June 2017. We expect US onshore natural gas production to continue to grow in the second half of 2017, supported by rising associated gas supply from shale oil, and the increase in the natural gas rig count seen over the last 12 months.

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 supply/demand the end of August were reported by the EIA to be 3,466 Bcf. The 78 bcf average weekly injection in inventories during September was broadly in line with the ten-year average weekly rate of 74 bcf, meaning that inventories maintained their level relative to long run averages.

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



Source: Bloomberg; EIA (September 2017)

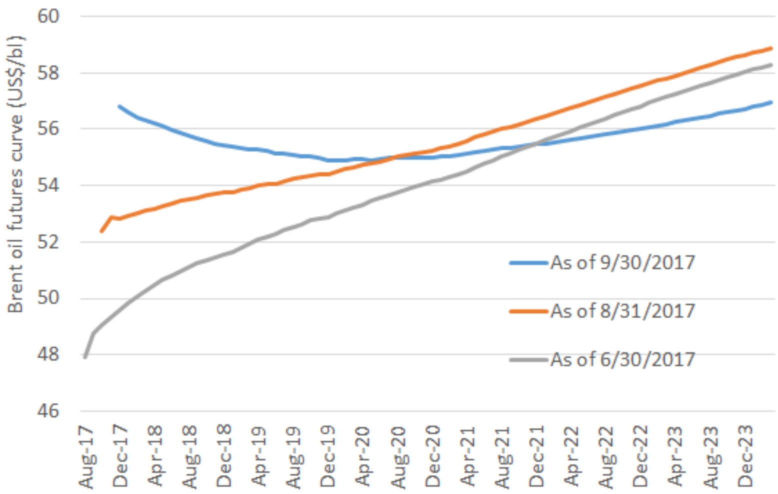
2. MANAGER'S COMMENTS

After a poor start to the year, the third quarter delivered stronger energy commodity and energy equity performance. We have seen improved fundamentals and sentiment throughout the sector after a difficult first half of the year. Here, we cover a number of the fundamental reasons for the recovery in oil prices and energy equities over the quarter with a summary of what is currently 'priced into' energy equities.

Brent crude oil prices were up sharply over the quarter (a clear positive factor for energy sector sentiment) but, more importantly, the Brent oil forward curve moved from contango into backwardation late in the quarter. We view the structure of the forward curve as being just as important as the level of spot oil price and note that this is the first time since August 2014 that the Brent oil forward curve has been in backwardation. The backwardated curve (front month price being higher than 12 month forward price) indicates tight near term supply and demand fundamentals in the Brent oil market.

Brent oil forward curve has moved from contango into backwardation

Grey line = Brent futures curve as of end June 2017, Orange = end August 2017, Blue = end September 2017



Source: Bloomberg

We see a number of reasons for the recovery in front month oil prices and for the return of backwardation to the global crude oil markets:

- **Global oil demand growth being revised higher.** The International Energy Agency (IEA) has steadily increased its estimates for 2017 demand throughout the year. Demand in 2Q was particularly strong and expectations are that demand growth will continue to be robust for the remainder of 2017. IEA expectations for 2017 world oil demand have increased from 1.3m b/day at the start of 2017 to 1.6m b/day in the most recent IEA Oil Monthly report. 2017 demand growth is split 0.4m b/day from the OECD and 1.2m b/day for the non-OECD, indicating continued strong demand trends across both regions. The IEA expects these trends to continue. We noted with interest that it is now forecasting that world oil demand will exceed 100m b/day on average in 3Q 2018, five years earlier than they were predicting only 18 months ago. Clearly, low oil prices have had a beneficial impact on world oil demand levels and we would expect weaker oil demand growth if oil prices start to rise. However, should oil stay at $50/bl until 2020, then the 'world oil bill' as a percentage of world GDP would be only 2% (substantially lower than the 30 year average 'world oil bill' of 3%). Crude oil is currently a 'cheap' commodity for consumers, in our opinion, and we expect to see strong demand while prices and the economic burden of crude oil remain low.

- **Signs of lower US oil production growth potential.** A number of US E&Ps have indicated that either supply chain/logistics factors or subsurface issues (for example higher gas vs oil production ratios) have delayed their proposed ramp up of new oil supply and/or caused the E&Ps to suffer greater than expected cost inflation. These are the first signs of the US onshore system suffering disefficiencies in the upcycle and we sense that market expectations of US growth being in excess of 1m b/day per year have now been pared back somewhat. Monthly production data from the EIA reported US onshore production growth of only 5k b/day in June and 52k b/day in July versus prior indications (from the EIA's own weekly data and their Drilling Productivity Report) that growth would be more like 100k/day per month. We wait to see if this is a trend or a one-off 'wobble' but note that higher levels of activity and investment are very likely to cause sustained infrastructure and supply chain issues, although an active service industry will obviously endeavour to overcome these issues.

- **Increased confidence in OPEC's action.** Over the quarter, OPEC delivered sustained high levels of compliance on current production quotas and we saw evidence that OPEC oil exports are now falling as well. At the end of August 2017, OPEC production compliance appeared to be at around 85%. There have been continued ad-hoc OPEC meetings and announcements through the quarter, raising the likelihood that current quota cuts are extended beyond March 2018, when they are currently due to end. In informal comment, OPEC ministers have provided some confidence that the group will not immediately return their extra supply onto the market, which would risk near term oversupply and potentially weaker oil prices. We do not expect any firm commitments from OPEC until much nearer to March 2018 and note that OPEC countries still need higher oil prices to balance their government budgets. As an example, the foreign currency reserves of Saudi Arabia fell by a further $36bn in the first half of 2017 with Brent oil prices averaging $52/bl over the period.

In addition to improving supply and demand fundamentals for oil, we believe that underlying fundamentals are improving for the companies and there are signs of improving capital discipline and free cash generation. Here, we discuss some examples of this:

- **Capital discipline from the US E&P community.** Anadarko, a $25bn market cap international E&P, announced a $2.5bn share repurchase plan in late September, driving the stock up 8% on the day. Since then, Anadarko shares have risen by 11% while its nearest peers Apache, Devon Energy, Noble Energy and Hess Corporation) are up by 4.3% and 5.7%. The positive share price reaction gives us hope that other US domiciled E&Ps will shift from growth to a better focus on capital discipline and profitability. This would also have positive implications for the macro oil supply picture, as greater capital discipline would cap the growth of US onshore oil production.

- **Free cash flow generation from Canadian large-caps.** The larger Canadian oil sands focused companies such as Suncor and Canadian Natural Resources has been working energetically to improve free cashflow at WTI $50/bbl. Suncor, for example, has achieved oil sands operating cost reductions of 19% so far in 2017 versus 2016. With a sharp drop off in oil sands growth projects coming into the end of the decade, there will be an increasingly loose service market, which will help to control capex costs and sustain the cash profitability of mature producing companies in this sector. This in turn means growing dividends and larger share buybacks.

- **Free cash flow generation from European integrateds.** According to Goldman Sachs, European oil companies delivered a higher level of free cash flow generation in 1H 2017 (based on a $52 Brent oil price) than they delivered in 1H 2014 (based on a $109/bl Brent oil price). The improved free cash generation comes as a result of both lower operating costs and lower capital expenditure and means that the same group of companies should be able to cover their full dividend commitments and capex from their operating cash flow at around $50-55/bl oil. This is the first indication that scrip dividends could be removed and that the attractive dividend yields of the European oils would be sustained at current oil prices.

- **Bad news discounted in prices.** Expectations are low and we are tempted to believe that the energy sector could deliver ahead of expectations from here. For example, RD/Shell trades at a nearly 7% dividend yield yet its cash dividend now looks likely to be fully covered by cash generation from 2018 onwards and its Credit Default Swap (CDS) is now trading at about the same level as ExxonMobil. In 'normal' market conditions, we would have expected RD/Shell's dividend yield to be closer to 5% rather than the current 7%. We think it is fair to say that RD/Shell's equity, in common with a number of other oil majors, is priced for a weaker oil and gas environment than we have today.

The outcome of the recovery in energy equities is that, based on our valuation work, we see the implied oil prices in the fund's holdings as being around $53/bl currently. Put another way, if we put $53/bl into our company models for next year (2018) our model portfolio holdings would be trading at around 6.5x EV/EBITDA (a level we deem as reasonable given the profitability and growth prospects of the portfolio). To put this into context, the oil price implied in our holdings fell to a low of around $48/bl in early 2016 (when oil prices fell to $28/bl) and it got to highs of around $80/bl when oil prices were as high as $100/bl in the 2011-2014 timeframe. Should the implied oil price recover to $60/bl, then we would see around 30% upside in the equities and more like 70% upside if $70/bl is implied in the equities.

3. PERFORMANCE Guinness Global Energy Fund

The main index of oil and gas equities, the MSCI World Energy Index, was up by 9.4% in September, while the MSCI World Index rose by 3.1%. The Fund was up by 11.6% (class E) in the month, outperforming the MSCI World Energy Index by 2.2% (all in US dollar terms).

Within the Fund, August's strongest performers were Hess, Unit Corp, Noble Energy, Oasis and Tullow while the weakest performers were Sunpower, Enbridge, OMV, Petrochina and Gazprom.

Performance (in USD) 30/09/2017

Annualised

% returns	1 year	3 years	5 years	10 years	1999 to date
Guinness Global Energy	1.8	-12.7	-3.1	-2.0	10.1
MSCI World Energy Index	6.6	-5.5	0.4	0.0	7.0

Calendar year

% returns	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007
Guinness Global Energy	-6.8	27.9	-27.6	-19.1	24.4	3.0	-13.6	15.3	61.8	-48.2	37.6
MSCI World Energy Index	-0.9	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 (1.00% AMC) from launch to 02.09.08, and class E (0.75% AMC) 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.

4. PORTFOLIO Guinness Global Energy Fund

Buys/Sells

In September we purchased a 'research' position in Reabold Resources. Reabold is a UK AIM-listed resources investment company which raised equity and announced new management in September, with the aim of investing in small E&P special situations in Europe. We are attracted to Reabold by the opportunities that the new management team are planning to exploit, at a time when valuations in pre-cashflow oil and gas assets remain close to cyclical lows.

Sector Breakdown

The following table shows the asset allocation of the Fund at **September 30 2017**. We have also shown the asset allocation of the Guinness Atkinson Global Energy Fund (our US global energy fund which was started in 2004 and is managed in tandem with the Guinness Global Energy Fund) at year-end 2007 for comparative purposes:

(%)	31 Dec 2008	31 Dec 2009	31 Dec 2010	31 Dec 2011	31 Dec 2012	31 Dec 2013	31 Dec 2014	31 Dec 2015	31 Dec 2016	30 Sept 2017	*Change YTD*
Oil & Gas	***96.4***	***98.2***	***93.3***	***97.9***	***97.3***	***93.7***	***93.7***	***95.1***	***96.7***	***96.9***	***1.6***
Integrated	41.6	35.9	33.0	30.9	30.4	29.2	27.0	30.4	32.5	29.6	*2.1*
Integrated – Can & Em Mkts	12.1	11.9	8.2	8.8	8.4	9.4	10.3	11.1	14.3	14.6	*3.2*
Exploration & production	28.7	32.8	37.1	41.1	40.3	35.4	36.2	36.5	35.4	35.1	*-1.1*
Oil & Gas Storage & Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	*0.7*
Drilling	5.2	8.5	6.1	5.9	7.1	6.4	3.3	1.5	2.2	1.7	*-2.8*
Equipment & services	6.4	5.9	5.4	6.1	7.4	9.8	13.4	11.4	8.6	8.7	*-0.5*
Refining and marketing	2.4	3.2	3.5	5.1	3.7	3.5	3.5	4.2	3.7	3.7	***-3.8***
Solar	**0.0**	**0.0**	**3.2**	**1.3**	**1.2**	**2.6**	**3.7**	**4.7**	**0.9**	**1.2**	***0.0***
Coal & consumables	**2.3**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	***0.0***
Construction & engineering	**0.4**	**0.3**	**0.3**	**0.4**	**0.6**	**1.0**	**0.0**	**0.0**	**0.0**	**0.0**	***2.2***
Cash	**0.9**	**1.5**	**3.2**	**0.4**	**0.9**	**2.7**	**2.6**	**0.2**	**2.4**	**1.9**	
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	

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

The Fund at September 30 2017 was on a price to earnings ratio (P/E) for 2017 of 24.9x versus the S&P 500 Index at 19.8x as set out in the following table:

	2011	2012	2013	2014	2015	2016	2017	2018
Guinness Global Energy Fund P/E	7.5	7.8	8.5	9.3	20.2	36.1	24.9	19.9
S&P 500 P/E	26.1	26.0	23.5	21.7	25.1	23.8	19.8	17.4
Premium (+) / Discount (-)	*-71%*	*-70%*	*-64%*	*-57%*	*-20%*	*52%*	*25%*	*14%*
Average oil price (WTI $/bbl)	95	94	98	93	49	43		

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

Portfolio holdings

Our integrated and similar stock exposure (c.44%) 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 September 30 2017 the median P/E ratios of this group were 17.3x/17.0x 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.35%) 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 4.4x 2017 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 10% 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 August 31st 2017 (for compliance reasons disclosed one month in arrears)

Guinness Global Energy Fund 31 August 2017													
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	3.78	21.0	11.5	8.0	8.7	9.7	11.2	29.6	77.6	26.5	22.0
Royal Dutch Shell PLC	EUR	NL	3.83	12.6	8.9	6.6	6.5	8.6	7.6	16.2	26.6	16.0	14.1
BP PLC	GBP	GB	3.67	7.4	5.1	5.1	6.4	7.9	9.4	16.5	31.5	20.5	15.6
Total SA	EUR	FR	3.84	12.1	9.5	8.5	8.1	9.0	9.2	11.7	13.9	13.0	11.9
ENI SpA	EUR	IT	4.02	9.2	7.0	6.7	6.6	10.5	12.2	57.0	nm	23.1	18.6
Statoil ASA	NOK	NO	4.24	10.9	8.2	7.1	6.3	7.7	10.9	26.4	133.7	16.6	17.9
Hess Corp	USD	US	3.29	20.3	7.5	6.5	6.6	6.8	9.3	nm	nm	nm	nm
OMV AG	EUR	AT	4.09	19.4	12.1	15.2	10.6	13.0	16.0	14.3	14.6	12.0	13.4
			30.76										
Integrated / Oil & Gas E&P - Canada													
Suncor Energy Inc	CAD	CA	4.20	37.1	24.7	11.0	12.2	12.3	12.2	34.8	nm	30.4	33.4
Canadian Natural Resources Ltd	CAD	CA	3.97	16.0	15.8	16.6	24.2	17.1	11.2	276.8	nm	45.0	29.2
Imperial Oil	CAD	CA	3.97	18.6	16.1	10.0	8.9	11.5	9.7	20.7	61.2	34.5	25.7
			12.14										
Integrated Oil & Gas - Emerging market													
PetroChina Co Ltd	HKD	HK	3.60	7.1	5.7	5.6	6.4	7.1	7.0	21.8	85.5	26.5	20.3
Gazprom OAO	USD	RU	3.66	4.2	3.3	2.2	2.3	2.1	3.3	2.4	3.1	4.1	3.7
			7.26										
Oil & Gas E&P													
Occidental Petroleum Corp	USD	US	3.91	16.1	10.6	7.2	8.6	8.6	10.3	359.6	nm	81.7	45.9
ConocoPhillips	USD	US	3.60	12.1	7.4	5.1	7.7	7.8	8.2	nm	nm	237.3	38.0
Apache Corp	USD	US	3.10	7.0	4.2	3.3	4.1	4.8	6.9	nm	nm	1688.7	92.5
Devon Energy Corp	USD	US	3.21	9.6	5.3	5.2	9.7	7.4	6.1	12.7	nm	18.5	15.3
Noble Energy Inc	USD	US	2.85	14.0	11.5	9.1	10.4	7.7	10.2	417.0	nm	nm	276.4
QEP Resources Inc	USD	US	1.46	nm	5.5	4.6	6.1	5.4	5.4	nm	nm	nm	nm
Newfield Exploration Co	USD	US	3.00	5.1	5.7	6.4	10.8	14.5	14.2	36.0	24.3	13.8	11.5
Oasis Petroleum Inc	USD	US	1.55	nm	43.5	8.8	4.9	2.6	3.0	9.2	nm	nm	nm
			22.68										
International E&Ps													
CNOOC Ltd	HKD	HK	4.07	11.6	6.7	5.1	5.4	5.5	6.6	19.7	nm	12.7	11.1
Tullow Oil PLC	GBP	GB	1.96	31.1	15.1	3.5	3.1	23.3	nm	nm	nm	63.3	15.1
Soco International PLC	GBP	GB	0.80	9.0	12.4	8.0	2.2	2.4	3.6	nm	nm	nm	35.9
			6.84										
Midstream													
Enbridge Inc	USD	CA	3.72	55.1	47.6	42.9	39.5	36.4	33.4	30.2	27.9	31.4	25.1
			3.72										
Drilling													
Unit Corp	USD	US	1.46	6.0	5.2	3.9	3.8	4.3	3.7	nm	nm	29.3	12.2
			1.46										
Equipment & Services													
Halliburton Co	USD	US	3.33	29.8	19.4	11.7	13.1	12.6	9.9	26.4	nm	35.1	17.8
Helix Energy Solutions Group Inc	USD	US	1.75	10.8	11.9	4.2	3.4	5.8	3.2	37.1	nm	nm	37.5
Schlumberger Ltd	USD	US	3.37	23.4	23.0	17.5	15.2	13.3	11.5	19.0	55.0	42.1	27.2
			8.44										
Solar													
JA Solar Holdings Co Ltd	USD	US	0.85	nm	0.9	nm	nm	nm	7.5	3.8	8.8	19.2	15.1
Sunpower Corp	USD	US	0.53	7.7	6.1	107.8	58.9	6.3	6.7	4.5	nm	nm	28.2
			1.37										
Oil & Gas Refining & Marketing													
Valero Energy Corp	USD	US	3.73	nm	42.9	17.1	13.9	16.6	11.2	7.8	18.5	16.7	12.5
			3.73										
Research Portfolio													
Cluff Natural Resources PLC	GBP	GB	0.22	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm
EnQuest PLC	GBP	GB	0.45	nm	3.7	4.3	1.3	1.4	2.6	25.2	1.7	nm	4.7
JKX Oil & Gas PLC	GBP	GB	0.08	0.4	0.4	0.5	0.7	1.3	3.6	nm	nm	nm	nm
Ophir Energy PLC	GBP	GB	0.05	nm	nm	nm	nm	nm	3.1	nm	nm	nm	nm
Shandong Molong Petroleum Machiner	HKD	HK	0.05	6.8	2.7	3.7	nm	nm	nm	nm	nm	nm	nm
Sino Gas & Energy Holdings Ltd	AUD	AU	0.12	nm	nm	nm	80.0	nm	80.0	nm	nm	nm	11.4
			0.96										
		Cash	0.64										
		Total	100										
		PER		12.3	8.0	6.7	6.9	7.6	8.3	18.1	32.5	22.6	17.6
		Med. PER		11.8	8.2	6.7	7.1	7.8	9.2	21.3	26.6	26.5	17.9
		Ex-gas PER		13.0	8.5	7.0	7.0	8.0	8.7	17.4	29.7	21.7	16.9

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.

5. 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 2017 and 2018.

	2005	2006	2007	2008	*2009*	2010	2011	2012	2013	2014	2015	2016	2017E	2018E
													IEA	*IEA*
World Demand	**84.0**	**85.2**	**87.0**	**86.5**	**85.5**	**88.5**	**89.5**	**90.7**	***91.7***	***92.9***	***94.8***	***96.1***	***97.7***	***99.1***
Non-OPEC supply (includes Angola, Ecuador and Indonesia for periods when each country was outside OPEC[1])	**50.4**	**51.3**	**50.5**	**49.6**	**51.4**	**52.7**	**52.8**	**53.3**	***54.5***	***56.7***	***58.2***	***56.8***	***57.5***	***59.0***
Angola supply adjustment[1]	-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	0.0	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]	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)	**49.6**	**50.3**	**51.0**	**50.6**	**51.4**	**52.7**	**52.8**	**53.3**	**54.5**	**56.7**	**58.2**	**57.4**	**58.1**	**59.6**
OPEC NGLs	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)	**53.9**	**54.6**	**55.3**	**55.1**	**56.5**	**58.2**	**58.7**	**59.7**	**60.6**	**63.1**	**64.8**	**64.2**	**65.0**	**66.6**
Call on OPEC-12[3]	30.1	30.6	31.7	31.4	29.0	30.3	30.8	31.0	31.1	29.8	30.0	31.9	32.7	32.5
Iraq supply adjustment[4]	-1.8	-1.9	-2.1	-2.4	-2.4	-2.4	-2.7	-3.0	-3.1	-3.3	-4.0	-4.4	-4.4	-4.4
Call on OPEC-11[5]	**28.3**	**28.7**	**29.6**	**29.0**	**26.6**	**27.9**	**28.1**	**28.1**	**28.0**	**26.5**	**26.0**	**27.5**	**28.3**	**28.1**

[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
[3]Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi, U.A.E. Venezuela
[4]Iraq has no offical quota
[5]Algeria, Angola, Ecuador, Iran, Kuwait, Libya, Nigeria, Qatar, Saudi, U.A.E. Venezuela

Source: 2003 - 2008: IEA oil market reports; 2009 - 17: September 2017 Oil market Report

Global oil demand in 2017 is set to be over 10m b/day higher than the pre-recession (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 1.4m b/day in 2018, which would take oil demand to an all-time high of 99.1m b/day.

OPEC

In December 2011, OPEC-12 introduced a group-wide target of 30m b/day without specifying individual country quotas. The 30m b/day figure included 2.7m b/day for Iraq, so the target for OPEC-11 (excluding Iraq) was 27.3m b/day.

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:

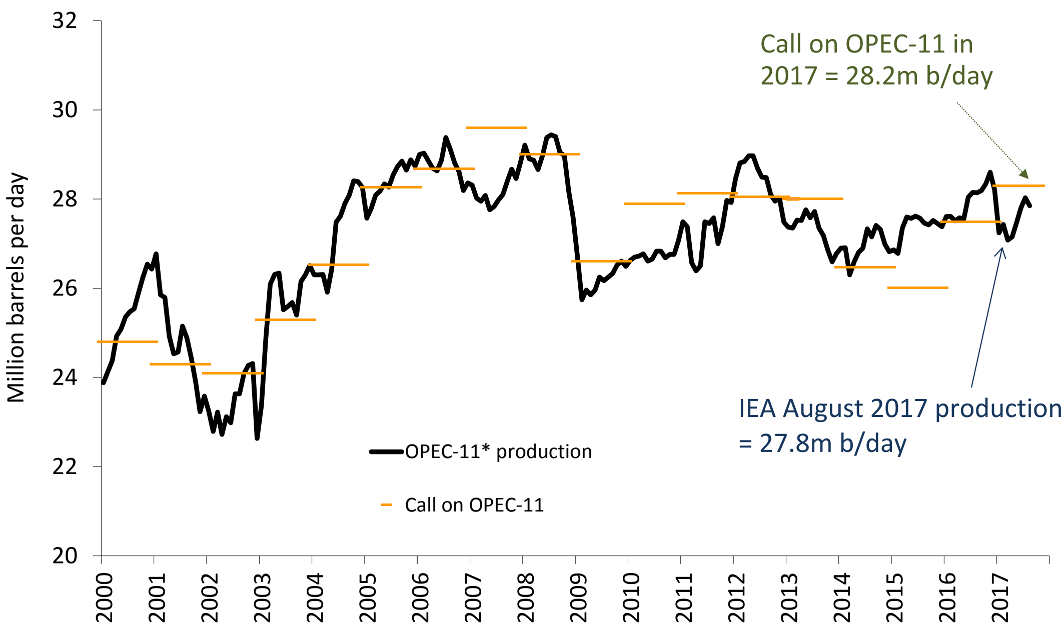
('000 b/day)	31-Dec-10	30-Nov-14	31-Aug-17	Change vs Dec 2010	Change vs Nov 2014
Saudi	8,250	9,650	**10,000**	**1,750**	**350**
Iran	3,700	2,780	**3,790**	90	**1,010**
Iraq	2,385	3,370	**4,490**	2,105	**1,120**
UAE	2,310	2,800	**2,920**	610	**120**
Kuwait	2,300	2,790	**2,710**	410	**-80**
Nigeria	2,220	1,970	**1,750**	-470	**-220**
Venezuela	2,190	2,350	**1,970**	-220	**-380**
Angola	1,700	1,640	**1,660**	-40	**20**
Libya	1,585	580	**890**	-695	**310**
Algeria	1,260	1,100	**1,060**	-200	**-40**
Qatar	820	650	**610**	-210	**-40**
Ecuador	465	561	**530**	65	**-31**
OPEC-12	**29,185**	30,241	**32,380**	**3,195**	**2,139**

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 – 2017



Source: IEA Oil Market Report (August 2017 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. In May 2017, OPEC met to consider extending the cuts and agreed, together with key non-OPEC producers, to extend the cuts for a further nine months (to the end of March 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.

Clearly, OPEC economies are under significant stress, which is the near-term driver for the decision to cut in 2017. 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 (though $75-80/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.

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 2008-2016.

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. The IEA forecasts that non-OPEC supply recovers by 0.7m b/day in 2017, as US onshore production swings from decline back to growth.

The growth in US shale oil production, in particular from the Permian, Bakken and Eagleford basins, 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 and has now returned to growth. Our assessment is that US shale oil is a capital intensive source of oil but one where 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. Naturally, cashflows available for reinvestment in a $40-60 world are far lower than in a $100 world, but with efficiency improvements and recent cost deflation, enough to see moderate growth returning.

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 expect 2017 growth of 1.6m b/day, and a further increase of 1.4m 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 forecast for 2017 comprises an increase in non-OECD demand of 1.2m b/day and OECD demand of 0.4m b/day. The components of this non-OECD demand growth can be summarised as follows:

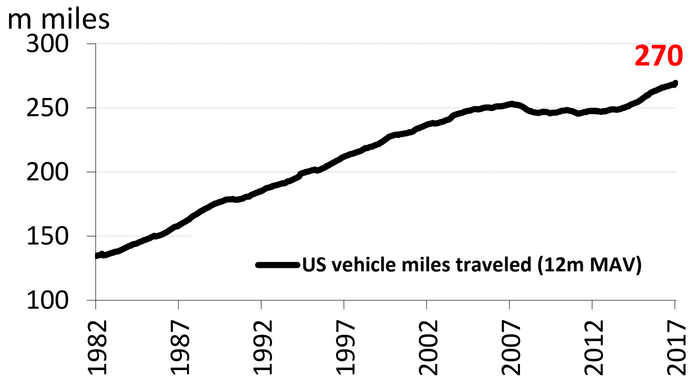
Figure 8: Non-OECD oil demand

m b/day	Demand								Growth						
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017e**	**2018e**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017e**	**2018e**
Asia	20.3	21.4	22.1	22.8	24.0	24.8	25.7	26.6	1.1	0.7	0.7	1.2	0.8	0.9	0.8
Middle East	7.4	7.8	7.9	8.4	8.4	8.3	8.3	8.5	0.4	0.1	0.5	0.0	-0.1	0.1	0.2
Latin America	6.2	6.4	6.7	6.8	6.7	6.6	6.6	6.7	0.2	0.3	0.1	-0.1	-0.1	0.0	0.1
FSU	4.4	4.6	4.7	4.66	4.6	4.8	4.8	4.9	0.2	0.1	0.0	-0.1	0.2	0.1	0.1
Africa	3.5	3.8	3.9	3.8	4.1	4.1	4.2	4.3	0.3	0.1	-0.1	0.3	0.0	0.1	0.1
Europe	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	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**	**49.3**	**50.5**	**51.7**	**2.2**	**1.3**	**1.2**	**1.2**	**0.9**	**1.2**	**1.3**

Source: IEA Oil Market Report (September 2017)

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, but signs are emerging that India may grow by as much, having made the largest contribution to growth in 2016.

OECD demand in 2017 is forecast to be up 0.4m 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 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 1.5-2%, the lowest level since 1998/99, and a likely stimulant of strong 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 average annual non-OECD demand growth of around 1.5m b/day to 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 0.8m in 2016, up from 0.4m in 2014. Sales of 0.8m electric vehicles represents around 1% of total light vehicle sales, and increases EV's share of the world car fleet to 0.15%. We expect to see EV sales accelerate in 2017 to around 1.2m, or 1.5% of total global sales. Even applying an aggressive growth rate to EV sales, we see EVs comprising only around 1% of the global car fleet in 2020.

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
WTI	30	33	38	49	66	75	82	104	68	84	99	94	98	93	49	45	50
Brent	30	32	35	46	64	75	82	103	67	84	115	112	108	99	52	45	52
Brent/WTI (12m MAV)	**30**	**33**	**37**	**48**	**65**	**75**	**82**	**104**	**68**	**84**	**107**	**103**	**103**	**96**	**51**	**45**	**51**
Brent/WTI y-on-y change (%)		8%	12%	30%	37%	15%	9%	26%	-35%	24%	27%	-4%	0%	-7%	-47%	-11%	13%
Brent/WTI (5yr MAV)	30	25	32	37	42	51	61	75	79	82	89	93	93	99	92	80	69

We expect oil to trade in a $45-60 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 moderate growth.

The world oil bill at around $50 per barrel would represent 2% of 2016 Global GDP, 42% 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 $85/barrel.

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

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 2016, 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	2017E	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	24.6	25.8
Industrial	18.2	18.2	16.9	18.5	19.0	19.7	20.3	20.9	20.6	21.1	21.4	21.6
Pipeline exports (Canada & Mexico)	2.1	2.5	2.8	2.9	4.1	4.4	4.4	4.1	4.9	6.3	6.7	7.3
LNG exports	-	-	-	-	-	-	-	-	0.1	1.0	3.1	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	6.4	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**	**86.2**
Demand growth	**4.0**	**0.8**	**- 0.6**	**3.2**	**2.5**	**3.0**	**1.8**	**0.9**	**3.0**	**2.6**	**0.5**	**3.1**

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 facilities planned 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.

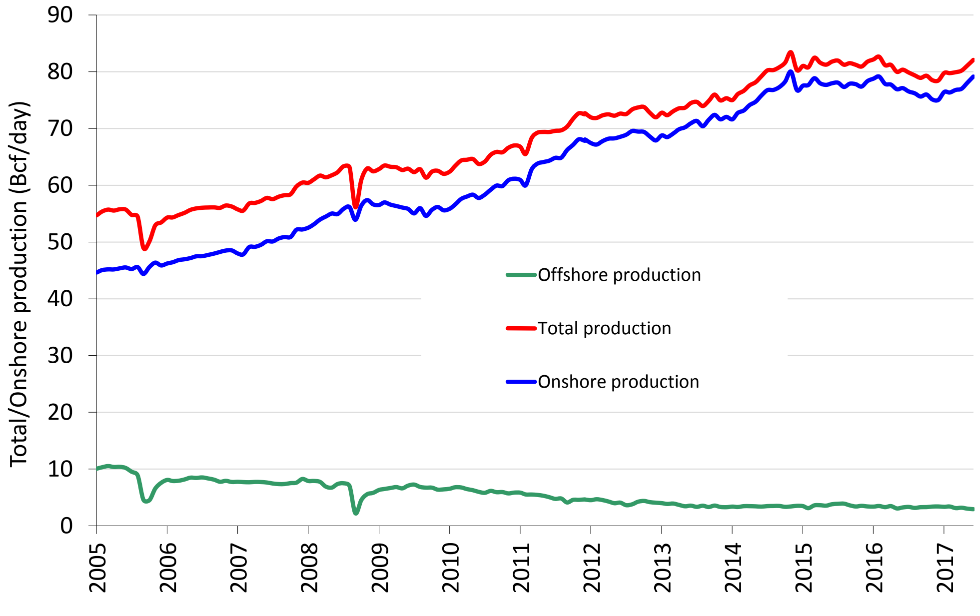
The supply side fundamentals for natural gas in the US are driven by 3 main moving parts: onshore and offshore domestic production, and pipeline imports of gas from Canada. Of these, onshore supply is the biggest component, making up over 85% of total supply.

Bcf/day	2007	2008	*2009*	2010	2011	2012	2013	2014	2015	2016	2017E	2018E
US natural gas supply:												
US onshore	45.1	48.8	49.8	52.2	57.7	61.5	63.1	67.5	70.5	68.9	69.9	75.4
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	7.9	7.4
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**	**74.8**	**78.5**	**81.7**	**80.7**	**81.3**	**86.4**
Supply growth	**3.2**	**0.6**	**0.8**	**1.9**	**3.4**	**2.3**	**0.3**	**3.7**	**3.2**	**-1.0**	**0.6**	**5.1**

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 189 at the end of September 2017. 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 79.1 Bcf/day, 21.7 Bcf/day (38%) above the 57.4 Bcf/d peak in November 2008 before the rig count collapsed.

Figure 10: US natural gross gas production 2005 – 2017 (Lower 48 States)



Source: EIA 914 data (July 2017 published in October 2017)

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.

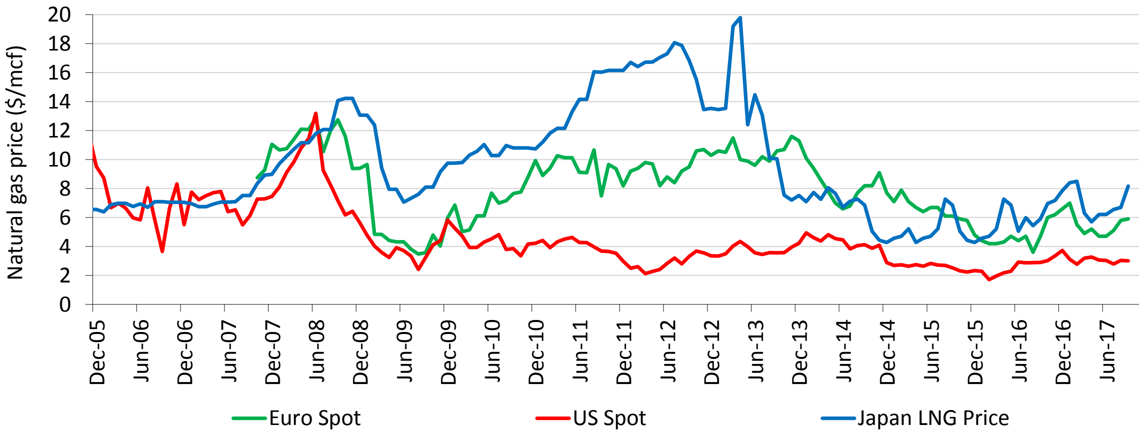
Associated gas production declined in 2016 with the fall of shale oil production, but as US oil supply now growing again, so associated gas production is also picking up. Generally, we expect to see rates of around 2-3 Bcf/day of associated gas per 1m b/day of oil production.

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.$6/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 $7-8/mcf. Given the structure of most LNG exports, being 'take or pay' contracts, the implied economics are tight at these levels but sufficient to expect exports to proceed.



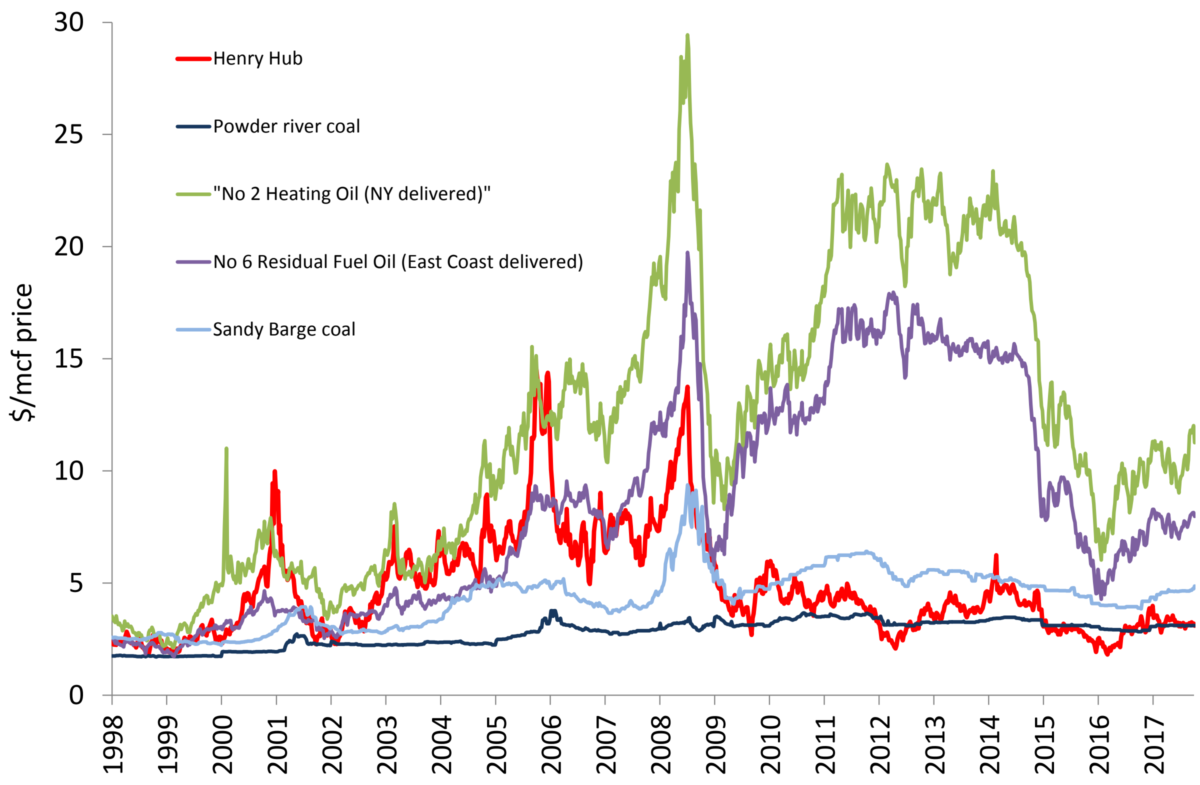
Relationship with oil and coal

The oil/gas price ratio ($ per bbl WTI/$ per mcf Henry Hub) of around 17x at the end of September 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 (October 2017)

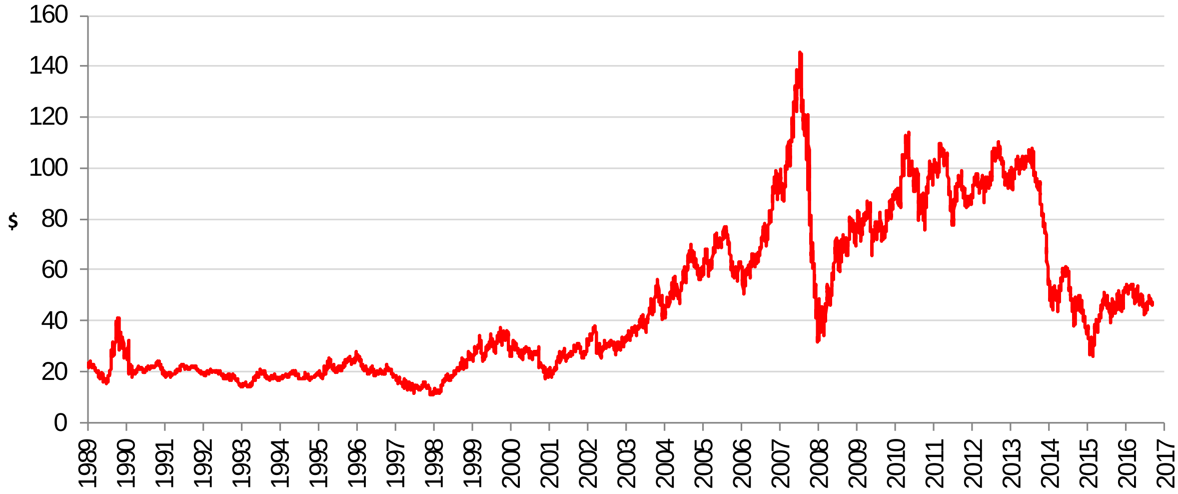
Conclusions about US natural gas

Bcf/day	2007	2008	*2009*	2010	2011	2012	2013	2014	2015	2016	2017E	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	86.2
Demand growth		0.8	- 0.6	3.2	2.5	3.0	1.8	0.9	3.0	2.6	0.5	3.1
Total supply	65.5	66.1	66.9	68.8	72.2	74.5	74.8	78.5	81.7	80.7	81.3	86.4
Supply growth		0.6	0.8	1.9	3.4	2.3	0.3	3.7	3.2	- 1.0	0.6	5.1
(Supply)/demand balance	- 0.1	0.1	- 1.3	-	- 0.9	- 0.2	1.3	- 1.5	- 1.7	1.9	1.8	- 0.2

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 $3.00 – 3.50 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 $3.50+.

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.

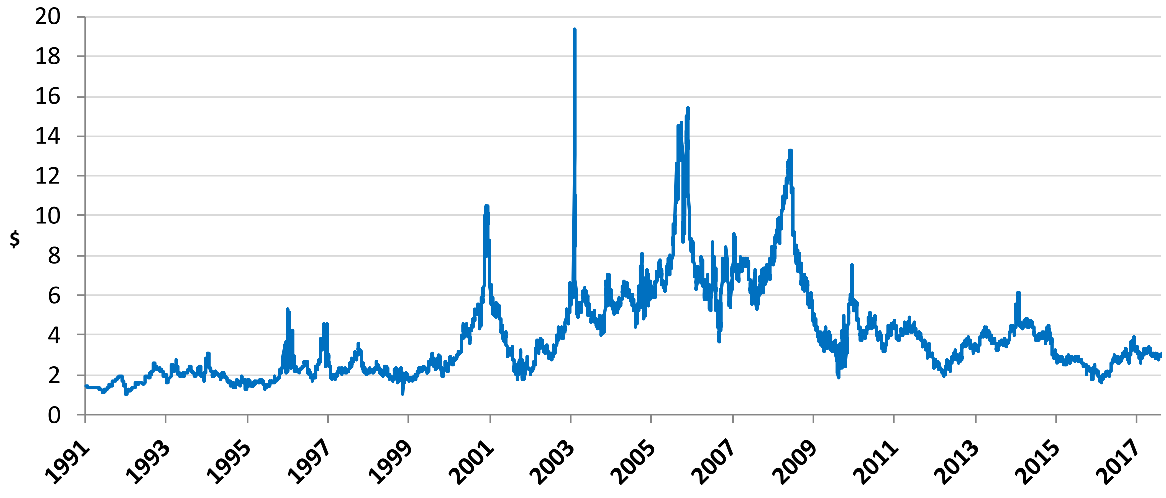
After 2005 we saw a further strong run-up in the oil price. Hurricanes Katrina and Rita, which devastated New Orleans, caused oil to spike up to $70 in August 2005, and it spiked up again in July 2006 to $78 after a three week conflict between Israel and Lebanon threatened supply from the Middle East. 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.

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