THE GUINNESS GLOBAL ENERGY REPORT

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

GUINNESS GLOBAL ENERGY FUND

Fund size: $276m (31.10.2018)

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.

HIGHLIGHTS FOR OCTOBER

OIL

Brent and WTI down; US wrestles with how to replace Iran supply

Brent and WTI both down over the month; Brent fell from $83/bl to $74/bl; WTI fell from $73/bl to $65/bl. Concerns over global slowdown spilling into fears over oil demand weakness; US talking up the likelihood of some import waivers for Iranian oil, to avoid too much of a price spike around the mid-term elections. US and OPEC production higher; OPEC spare capacity at historically low levels.

NATURAL GAS

US gas prices higher; European prices up sharply

Henry Hub prices were higher on the month, rising from $3.01/mcf to $3.26/mcf. Inventories at 10 year low levels, raising possibility of a winter price spike, but supply is responding (up 12 Bcf/day yoy). European gas prices staying elevated on high demand and marginal LNG cargoes being diverted into Asia.

EQUITIES

Energy underperforms the broad market

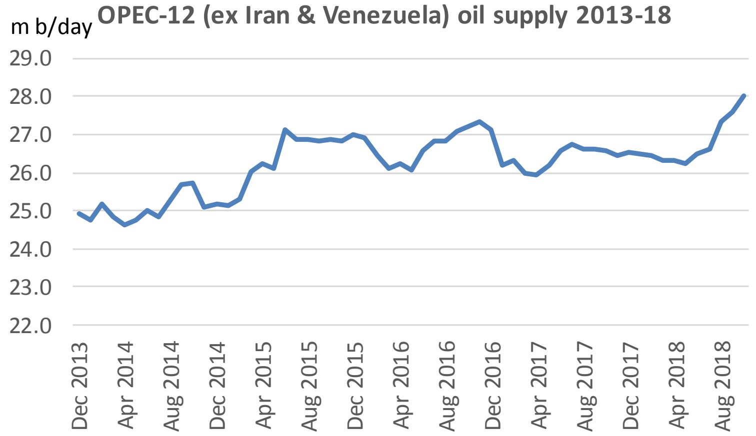
The MSCI World Energy Index fell in October by 10.1%, underperforming the MSCI World Index which fell by 7.3% over the month (all in US dollar terms). For the year to October 31 2018, the MSCI World Energy Index is behind the MSCI World by 1.5%.

CHART OF THE MONTH

OPEC (ex Iran & Venezuela) pumping at record level

OPEC-12 (ex Iran & Venezuela) has ramped production aggressively since May, up by 1.8m b/day to 28.2m b/day, their highest production on record. The main contributors have been Saudi (+0.7m b/day), UAE (+0.3m b/day) and Nigeria (+0.3m b/day). OPEC's stated intention has been to raise production to offset declines in Iran and Venezuela, so avoiding excessive tightness in the market. However, the extent of the increase leaves OPEC, we believe, with the lowest effective spare capacity in their history. Any further supply disruption from this point would pose a significant challenge to oil markets.

Iranian oil production



Source: Bloomberg, Guinness Asset Management

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

GUINNESS ASSET MANAGEMENT

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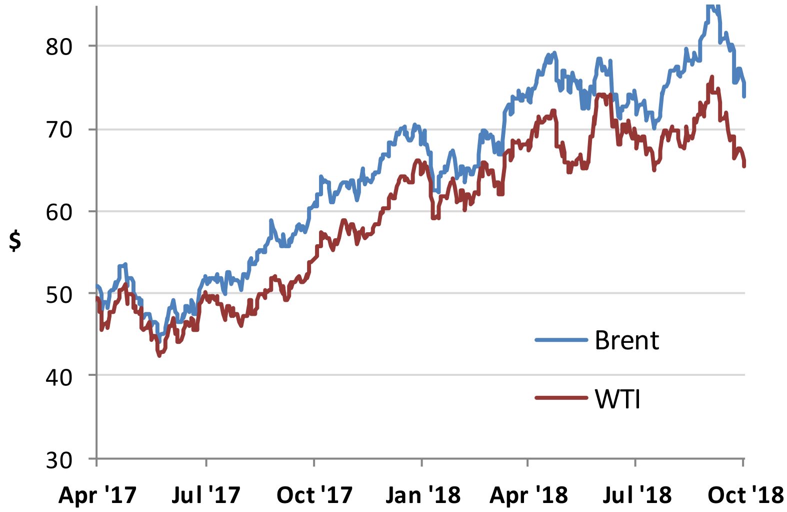
1. OCTOBER IN REVIEW

i) Oil market

Figure 1: Oil price (WTI and Brent $/barrel) 18 months April 30 2017 to October 31 2018



Source: Bloomberg LP

The West Texas Intermediate (WTI) oil price started October at $73.3/bl, briefly spiked up to $76.4/bl during the first week, then moved steadily down over the rest of the month to close on the low of $65.3/bl. WTI has averaged $67/bl so far in 2018, having averaged $51/bl in 2017, $43/bl in 2016, $49/bl in 2015 and $93/bl in 2014.

Brent oil traded in a similar shape, opening at $83.0/bl, spiking initially, then moving lower to end October at $73.9/bl. Brent has averaged $73/bl so far in 2018. The gap between the WTI and Brent benchmark oil prices narrowed slightly, ending October at just under $9/bl.

Factors which strengthened WTI and Brent oil prices in October:

- **IMO 2020 regulations confirmed**
  International Maritime Organisation rules to limit the use of high sulphur fuel oil by the shipping industry, starting in 2020, having meen a major talking point in the oil industry this year. From a demand perspective, the 'IMO 2020' are expected to drive demand for refined distillate higher, which in turn would increase overall demand for crude oil. In the middle of the month, the Trump Administration spoke of attempting to delay the rollout because of the impact that higher oil demand (and prices) may have on the US economy, comments which were negative to oil prices. However, on October 28th, the IMO confirmed that the 2020 timeline was a firm one. We do expect the regulations, therefore, to tighten the market in 2020.

- **Reduction in OPEC spare capacity**
  OPEC-12 (ex Iran & Venezuela) was reported as supplying 28.0m b/day in October 2018, up by 1.8m b/day since the start of the year. The increases in production have come largely since the middle of the year, and are designed to stop the market becoming overly tight in the face of production falls in Venezuela and Iran. However, we estimate that it leaves OPEC with spare capacity close to historic lows, somewhere around 1m – 1.5m b/day. This increases the 'tail' risk that any new episode of supply disruption causes an oil price spike, since OPEC would not be well equipped to compensate for it.

Factors which weakened WTI and Brent oil prices in October:

- **Economic slowdown fears impacting outlook for oil demand**
  October saw a growing fear that tariffs, protectionism and rising US interest rates could derail global GDP growth over the next twelve months. There were associated concerns about the negative impact on oil demand growth, pulling spot oil prices lower. Over the last couple of months, the IEA have lowered their forecast for 2019 oil demand growth from 1.5m b/day to 1.3m b/day, reflecting the IMF's downgrade of global GDP growth in 2019 from 3.9% to 3.7%. Demand growth of this amount would still be in line with the 5 year average.

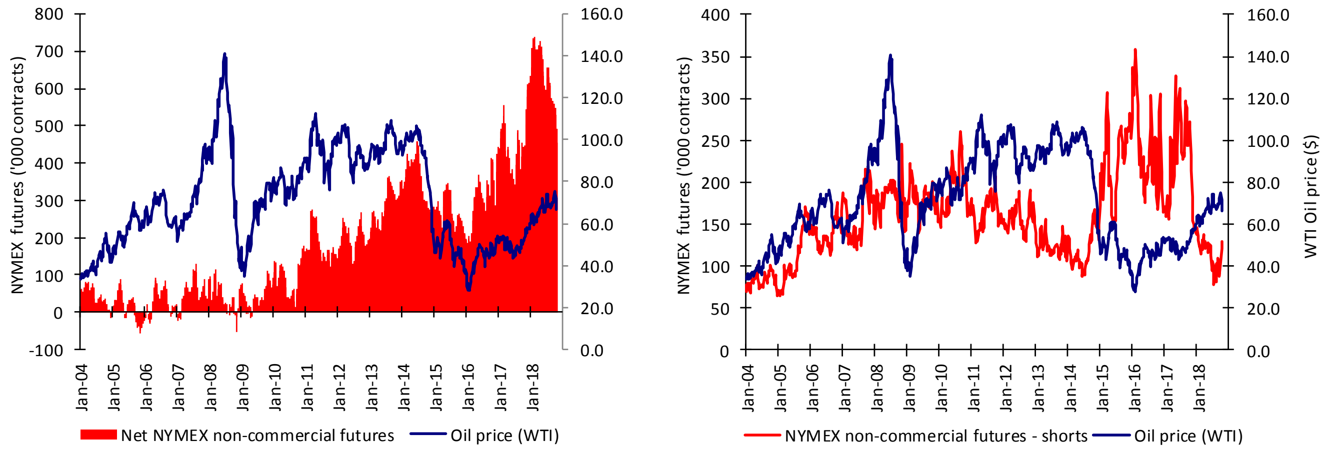
- **Iranian sanction waivers**
  Since the end of the summer there have been mixed messages about Iranian oil exports, and whether the US will allow some export waivers to soften the impact of the sanctions they have imposed. In the second half of October, with the US mid-term elections looming, the US became more dovish in its stance, and temporary waivers for countries such as India and South Korea looked likely. Iranian production fell in the third quarter by around 0.4m b/day (3.8m to 3.4m b/day), and even with some waivers in place, we expect it to fall to around 3m b/day by the end of the year.

- **Increase in US onshore oil supply**
  At the start of November, the EIA reported that US onshore production increased by 311k b/day during August 2018. This puts year over year growth for the US onshore system at around 1.9m b/day. Infrastructure constraints in the Permian basin have caused the oil directed rigcount to plateau, which we expect to dampen the rate of production growth in the remainder of 2018 and 2019.

Speculative and investment flows

The New York Mercantile Exchange (NYMEX) net non-commercial crude oil futures open position (WTI) was down sharply in October, ending the month at 455,000 contracts long versus 560,000 contracts long at the end of September. The net position peaked in February 2018 at 739,000 contracts long. Typically there is a positive correlation between the movement in net position and movement in the oil price. The gross short position incrased from 87,000 contracts to 130,000 contracts. This short position is now roughly back to the level at the start of the year.

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

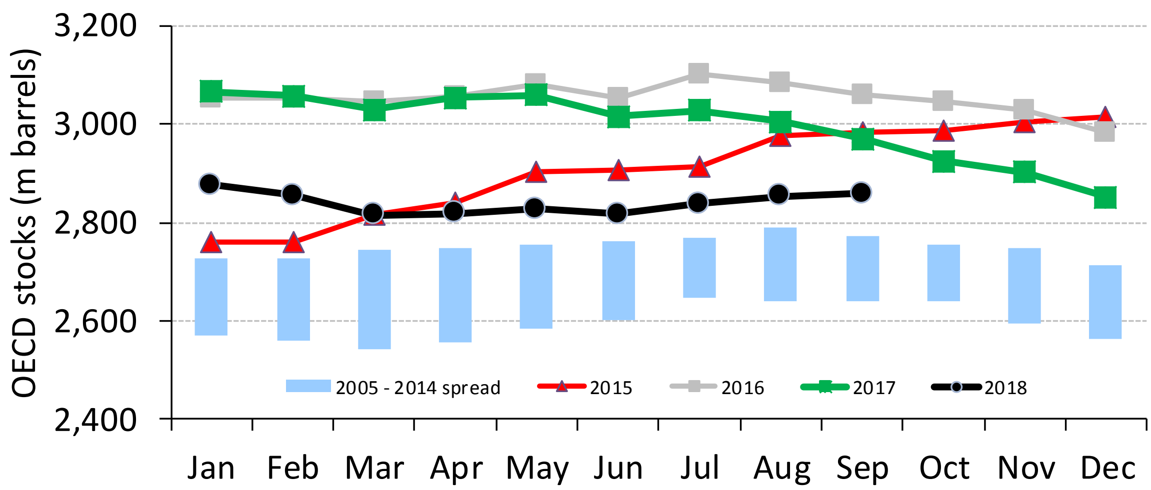


Source: Bloomberg LP/NYMEX/ICE (2018)

OECD stocks

OECD total product and crude inventories at the end of September (the latest data point available) were estimated by the IEA to be 2,860m barrels, up by 6m barrels versus the level reported for August. This compares to a 10-year average decrease for September of 11m barrels, implying that the market loosened by around 0.5m b/day. Inventories have been tightening since the middle of 2017, and remain around 60m barrels above the 'normalised' (pre-2015) range. We expect small tightening over the rest of 2018.

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



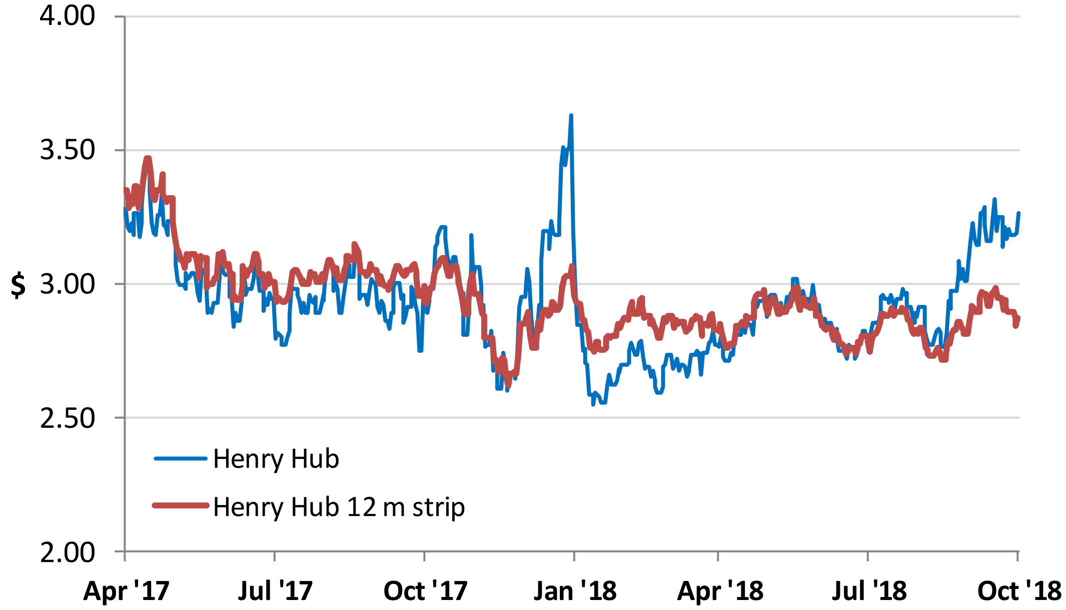
Source: IEA Oil Market Reports (October 2018 and older)

ii) Natural gas market

The US natural gas price (Henry Hub front month) opened October at $3.01/mcf (1,000 cubic feet), rose in the middle of the month to $3.32/mcf, then drifted off to end the month at $3.26/mcf. The spot gas price has averaged $2.86/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 12-month gas strip price (a simple average of settlement prices for the next 12 months' futures prices) also rose over the month, opening at $2.81/mcf and closing at $2.87 /mcf. The strip price averaged $3.12 in 2017, $2.84 in 2016 and $2.86 in 2015.

Figure 4: Henry Hub gas spot price and 12m strip ($/Mcf) April 30 2017 to October 31 2018



Source: Bloomberg LP

Factors which strengthened the US gas price in October included:

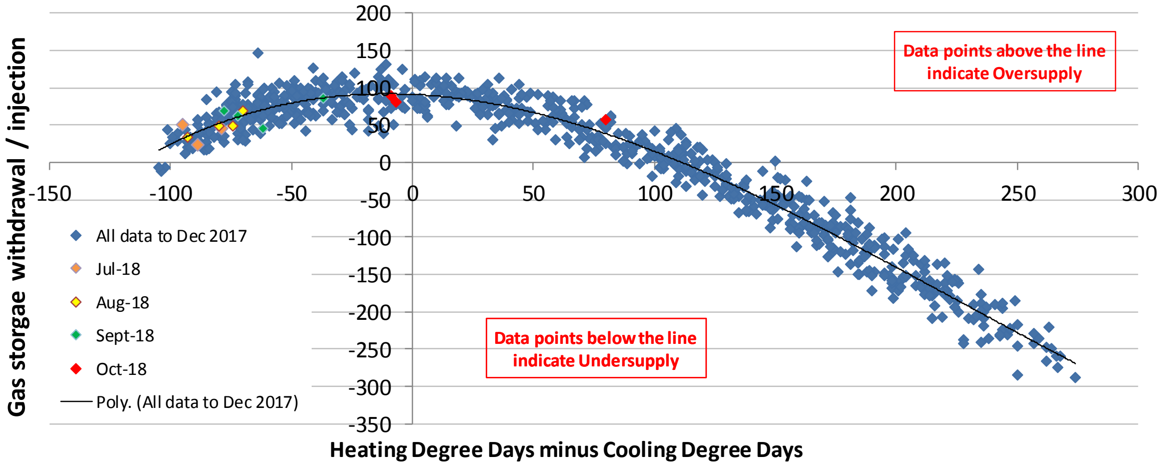
- **Depressed gas inventories**
  US natural gas inventories were estimated to be around 3.1 Tcf at the end of October, 0.6 Tcf lower than the 10-year average, and a 10 year low. Low inventories have pushed the gas price a little higher, though the market remains sanguine about the tightness of this market in the face of continued supply increases via associated gas (from shale oil) and the north-east of the the US.

Factors which weakened the US gas price in October included:

- **Strong US onshore natural gas production**
  Onshore US natural gas production averaged 91.7 Bcf/day in August 2018 (the latest available data point), up by 1.9 Bcf/day on the level reported for July. The biggest area of increase was Texas (mainly associated gas) up by around 0.4m b/day. Onshore production has risen by 12.1 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.

- **Structurally balanced market**
  Adjusting for the impact of weather in October, the most recent injections of gas into storage suggest the market is, on average, operating in balance (as indicated by the red dots on the graph below).

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

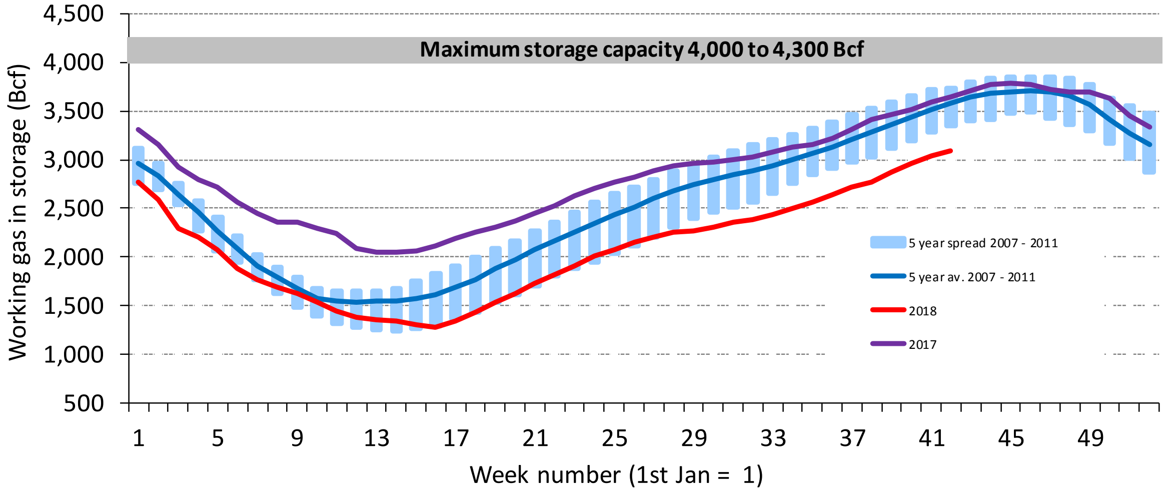


Source: Bloomberg LP; Guinness Asset Management

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 October were reported by the EIA to be 3.1 Tcf. The previous withdrawal season started with inventories peaking at 3.8 Tcf in mid-November 2017, the lowest starting point of the winter season for US gas inventories since November 2014. Seasonal temperature extremes and an undersupplied market has brought inventories to the bottom of the ten year range. Whilst gas inventories today are low, the high visibility of low cost supply growth for 2019 is keeping a cap on prices.

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



Source: Bloomberg; EIA (November 2018)

2. MANAGER'S COMMENTS

This month, we highlight the recent growing divergence between long dated oil prices and the valuation of energy equities. While energy equities suffered in broad equity market weakness during the month, we were comforted to see that long dated oil prices remained broadly unchanged. If long term relationships hold true then either long dated oil prices should fall or energy equities need to recover from here. With 3Q 2018 results confirming an improving outlook for profitability and the underlying oil supply/demand outlook remaining tight, we are tempted to believe that energy equities recover to match the relative strength in long dated oil prices.

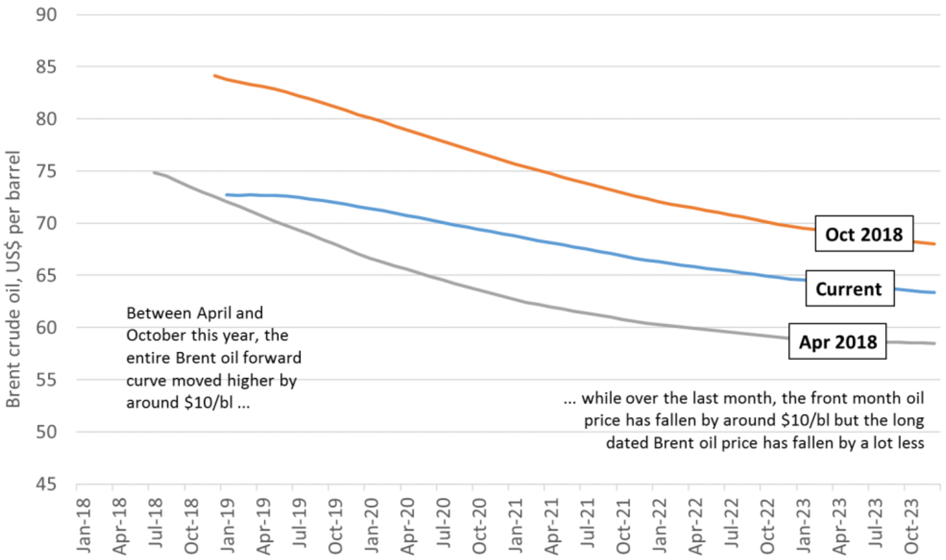
October witnessed a marked increase in the market concerns over global economic growth as a result of, amongst other things, trade wars and a slowdown in China. Our analysis of historic cycles shows that slowing economic growth brings slower world oil demand growth and, as a result, it is fair to expect that energy equities will have a negative reaction.

What we find particularly interesting in this current period of stock market weakness is that, while spot oil prices have fallen around $10 per barrel, long dated oil prices are broadly unchanged over the last month, with the average long dated price for Brent and WTI being around $61 per barrel (up over 10% over the last six months).

The forward curve for crude oil has been in steep backwardation for over a year now, with spot oil prices at an elevated level (due to OPEC quotas, Venezuela supply issues, US infrastructure issues and Iranian sanctions) while five year forward oil prices have remained relatively depressed (due to the expectation of bountiful US shale oil supply, industry cost deflation and the growth of electric vehicles). The forward curve has flattened in recent weeks as the five year forward, or long dated, oil price has risen as buyers and sellers of crude oil futures have started to become more concerned about the longer term supply demand balance for the oil industry. We believe that these long term supply/demand issues will continue to grow and we expect long dated oil prices to continue to rise, ultimately averaging around $70 per barrel in order to keep the industry in balance long term. The commodity market is starting to reflect these impending realities.

Brent oil forward curve: movements from April 2018 to October 2018 and current

Source: Bloomberg



Interestingly, this dynamic is being ignored in the equity markets. With energy equities off around 10% over the month of October, we now assess that the long dated oil price discounted in the valuation of our portfolio of energy equities is currently around $52 per barrel. Put another way, if we were to assume a $52 oil price forever, we would mark our energy equities as being at fair value. So, there is a difference of nearly $10 per barrel in the long dated oil price of the commodity markets and the one that is implied in energy equities.

This arbitrage is going to be closed by energy equities rising or by long dated oil prices falling, or by a combination of both. Our oil macro and energy equity analysis work makes us think that it is more likely that energy equities move up to close the arbitrage. Arbitrages of this scale don't persist for a long time in our markets and our valuation work implies that energy equities would need to rise around 25-30% from these levels if they were to price in a long term oil price of around $61/bl.

Our oil macro work tells us that $70 is a 'Goldilocks' long term oil price that would allow the oil industry to remain in long term balance. While there could of course be volatility in the long dated oil price, we believe that a weakening new project outlook from OPEC, a steepening base production decline curve from US shale oil and a delay in the start of new projects from non-OPEC means that long term oil prices need to be around that $70 per barrel level.

Our equity analysis tells us that the underlying profitability of the energy companies is recovering nicely. Return on Capital Employed for our portfolio of energy companies was only 2% in 2016 but is recovering to an estimated 7% in 2018 and we believe it is on a journey back to the 10-12% level that it has averaged over the last twenty years. Free Cash Flow is back to multi-year high levels and the companies continue to promote 'capital discipline' strategies that focus on improving returns to shareholders. While we have confidence that the companies will deliver on their ROCE and FCF objectives, the stock market still doesn't.

Initial 3Q2018 results from our energy companies are supportive of this recovering trend. Initial analysis of the European integrated oils shows that 3Q2018 free cash flow reached the highest levels that they have been for a decade. If this strong showing is sutained, then we believe that, over the next few quarters, the stock market will have to re-price energy equities to reflect the improved ROCE and FCF generation. Should strong long term correlations hold and our views on long term oil prices prove reasonably correct, the outlook for energy equities is very positive indeed. The onus is on the companies to sustain their capital discipline and deliver improved profitability and to prove to the stock market that the energy sector is, in fact, a very interesting deep value opportunity currently.

1) PERFORMANCE Guinness Global Energy Fund

The main index of oil and gas equities, the MSCI World Energy Index, was down by 10.1% in October, while the MSCI World Index fell by 7.3%. The Fund was down by 12.8% (class E) in the month, undperforming the MSCI World Energy index by 2.7% (all in US dollar terms).

Within the Fund, October's strongest performers were Enbridge, BP, OMV, Imperial Oil and Gazprom while the weakest performers were Anadarko, Noble Energy, Newfield, QEP and Oasis.

Performance (in USD) 31/10/2018

Annualised

% returns	1 year	3 years	5 years	10 years	1999 to date
Guinness Global Energy	2.8	2.9	-6.4	3.0	9.6
MSCI World Energy Index	2.7	4.7	-2.1	3.6	6.2

Calendar year

% returns	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007
Guinness Global Energy	-3.2	-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	-3.4	5.0	26.6	-22.8	-11.6	18.1	1.9	0.2	11.9	26.2	-38.1	29.8

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

There were no stock switches during the month.

Sector Breakdown

The following table shows the asset allocation of the Fund at **October 31 2018**.

(%)	31 Dec 2010	31 Dec 2011	31 Dec 2012	31 Dec 2013	31 Dec 2014	31 Dec 2015	31 Dec 2016	31 Dec 2017	30 Sept 2018	*Chg YTD*
Oil & Gas	***93.3***	***97.9***	***97.3***	***93.7***	***93.7***	***95.1***	***96.7***	***98.4***	***99.2***	***0.8***
Integrated	33.0	30.9	30.4	29.2	27.0	30.4	32.5	28.6	28.1	*-0.5*
Integrated – Can & Em Mkts	8.2	8.8	8.4	9.4	10.3	11.1	14.3	14.2	16.0	*1.8*
Exploration & production	37.1	41.1	40.3	35.4	36.2	36.5	35.4	37.0	37.5	*0.5*
Oil & Gas Storage & Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	3.6	*0.1*
Drilling	6.1	5.9	7.1	6.4	3.3	1.5	2.2	1.9	1.8	*-0.1*
Equipment & services	5.4	6.1	7.4	9.8	13.4	11.4	8.6	9.5	9.0	*-0.5*
Refining and marketing	3.5	5.1	3.7	3.5	3.5	4.2	3.7	3.7	3.2	*-0.5*
Solar	**3.2**	**1.3**	**1.2**	**2.6**	**3.7**	**4.7**	**0.9**	**1.4**	**0.4**	***-1.0***
Coal & consumables	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	***0.0***
Construction & engineering	**0.3**	**0.4**	**0.6**	**1.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	***0.0***
Cash	**3.2**	**0.4**	**0.9**	**2.7**	**2.6**	**0.2**	**2.4**	**0.2**	**0.4**	***0.2***
Total	**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 October 31 2018 was on a price to earnings ratio (P/E) for 2018 of 11.9x versus the S&P 500 Index at 17.3 as set out in the following table:

	2012	2013	2014	2015	2016	2017	2018	2019
Guinness Global Energy Fund P/E	8.0	8.7	9.5	20.8	35.9	22.2	11.9	9.7
S&P 500 P/E	28.0	25.3	23.0	27.0	25.6	21.8	17.3	15.4
Premium (+) / Discount (-)	*-71%*	*-66%*	*-59%*	*-23%*	*40%*	*2%*	*-31%*	*-37%*
Average oil price (WTI $/bbl)	94	98	93	49	43	51	65	

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 and OMV. At October 31 2018 the median P/E ratios of this group were 12.5x/10.5x 2018/2019 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.38%) 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 five other names (Apache, Occidental, ConocoPhillips, Noble, Anadarko) 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 2.8x 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.

Portfolio at September 30th 2018 (for compliance reasons disclosed one month in arrears)

Guinness Global Energy Fund 28 September 2018														
				2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
			% of	B'berg	B'berg	B'berg	B'berg	B'berg	B'berg	B'berg	B'berg	B'berg	B'berg	B'berg
Stock	Curr.	Country	NAV	mean PER	mean PER	mean PER	mean PER	mean PER	mean PER	mean PER	mean PER	mean PER	mean PER	mean PER
Integrated Oil & Gas														
Chevron	USD	US	3.67	23.8	13.1	9.1	9.9	11.0	12.7	33.6	88.2	29.5	15.3	13.2
Royal Dutch Shell PLC	EUR	NL	3.73	15.6	11.1	8.2	8.1	10.7	9.5	20.0	33.0	17.9	12.5	10.5
BP PLC	GBP	GB	3.77	9.8	6.8	6.8	8.4	10.4	12.4	21.9	41.8	24.9	13.8	12.3
Total SA	EUR	FR	3.66	15.6	12.2	10.9	10.4	11.6	11.7	15.1	17.8	16.6	12.2	10.8
ENI SpA	EUR	IT	3.54	11.4	8.7	8.3	8.1	13.0	15.1	70.5	nm	28.5	13.5	11.7
Equinor ASA	NOK	NO	3.74	16.1	12.2	10.5	9.4	11.5	16.0	39.2	198.7	20.7	14.1	12.7
OMV AG	EUR	AT	3.74	19.4	12.1	15.2	10.6	13.0	16.0	14.3	14.7	9.8	9.5	8.7
			25.85											
Integrated / Oil & Gas E&P - Canada														
Suncor Energy Inc	CAD	CA	3.56	47.3	31.5	14.0	15.5	15.7	15.6	44.4	nm	26.8	15.5	12.5
Canadian Natural Resources Ltd	CAD	CA	3.62	17.5	17.4	18.3	26.5	18.8	12.3	303.6	nm	35.9	11.8	11.1
Imperial Oil	CAD	CA	3.79	21.0	18.2	11.4	10.1	13.0	11.0	23.5	69.4	32.7	17.7	14.1
			10.98											
Integrated Oil & Gas - Emerging market														
PetroChina Co Ltd	HKD	HK	3.72	9.4	7.5	7.4	8.5	9.5	9.3	28.9	113.4	44.1	17.3	15.1
Gazprom OAO	USD	RU	3.83	5.9	4.6	3.1	3.3	3.0	5.0	3.1	4.5	5.0	3.1	3.0
			7.55											
Oil & Gas E&P														
Occidental Petroleum Corp	USD	US	3.66	22.1	14.6	9.9	11.8	11.8	14.1	495.0	nm	91.5	16.4	14.5
ConocoPhillips	USD	US	3.69	21.4	13.1	9.1	13.6	13.8	14.6	nm	nm	124.2	17.3	15.3
Anadarko Petroleum Corp	USD	US	3.29	nm	38.9	21.3	20.1	16.2	14.7	nm	nm	nm	23.2	16.2
Apache Corp	USD	US	3.64	8.6	5.1	4.0	5.0	5.9	8.5	nm	nm	449.7	26.4	25.8
Devon Energy Corp	USD	US	3.57	12.2	6.7	6.6	12.4	9.4	7.8	16.2	nm	21.8	26.8	15.1
Noble Energy Inc	USD	US	3.15	18.4	15.1	11.9	13.6	10.1	13.4	547.2	nm	1949.4	31.1	23.1
QEP Resources Inc	USD	US	1.72	nm	8.2	6.9	9.1	8.1	8.0	nm	nm	nm	nm	52.9
Newfield Exploration Co	USD	US	3.73	5.7	6.3	7.1	11.9	16.0	15.6	39.8	26.8	13.4	8.1	6.5
Oasis Petroleum Inc	USD	US	1.95	nm	84.4	17.2	9.6	5.1	5.8	17.8	nm	nm	34.6	15.1
			28.42											
International E&Ps														
CNOOC Ltd	HKD	HK	3.95	20.1	11.6	8.8	9.4	9.5	11.5	34.1	nm	19.7	10.8	9.8
Tullow Oil PLC	GBP	GB	1.94	52.6	25.5	5.8	5.2	39.3	nm	nm	nm	17.8	11.7	9.8
Soco International PLC	GBP	GB	0.52	6.6	9.0	5.8	1.6	1.7	2.6	nm	nm	nm	26.7	11.6
			6.41											
Midstream														
Enbridge Inc	USD	CA	3.26	46.1	39.8	35.9	33.0	30.5	27.9	25.2	23.4	28.4	20.5	22.5
			3.26											
Drilling														
Unit Corp	USD	US	1.77	9.9	8.6	6.4	6.3	7.1	6.1	nm	nm	49.1	30.7	21.6
			1.77											
Equipment & Services														
Halliburton Co	USD	US	3.68	31.0	20.2	12.1	13.6	13.1	10.3	27.4	nm	34.9	19.9	16.0
Helix Energy Solutions Group Inc	USD	US	1.83	17.0	18.7	6.6	5.3	9.2	5.1	58.5	nm	nm	50.9	27.8
Schlumberger Ltd	USD	US	3.52	22.4	22.1	16.8	14.6	12.8	11.0	18.2	52.7	41.7	34.0	24.0
			9.04											
Solar														
Sunpower Corp	USD	US	0.38	6.4	5.1	89.0	48.7	5.2	5.6	3.7	nm	nm	nm	nm
			0.38											
Oil & Gas Refining & Marketing														
Valero Energy Corp	USD	US	3.41	nm	71.7	28.6	23.3	27.7	18.7	13.0	30.9	23.3	17.4	11.0
			3.41											
Research Portfolio														
Cluff Natural Resources PLC	GBP	GB	0.20	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm
EnQuest PLC	GBP	GB	0.65	nm	6.1	7.0	2.1	2.3	4.3	41.3	2.7	nm	6.5	3.5
JKX Oil & Gas PLC	GBP	GB	0.08	1.0	1.1	1.3	1.8	3.5	9.6	nm	nm	nm	nm	nm
Ophir Energy PLC	GBP	GB	0.02	nm	nm	nm	nm	nm	1.5	nm	nm	nm	nm	5.9
Reabold Resources PLC	GBP	GB	0.32	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm
Shandong Molong Petroleum Machiner	HKD	HK	0.04	6.8	2.7	3.7	nm	nm	nm	nm	nm	nm	nm	nm
			1.33											
		Cash	1.61											
		Total	100											
		PER		15.9	11.3	8.9	9.3	10.0	10.9	23.8	41.4	25.3	14.0	11.8
		Med. PER		16.1	12.1	8.9	9.9	11.0	11.0	27.4	32.0	28.4	16.8	13.0
		Ex-gas PER		17.4	12.6	9.6	9.4	10.5	11.4	22.6	37.5	24.3	13.4	11.5

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 and 2019.

	2006	2007	2008	*2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018E	2019E
												IEA	*IEA*	*IEA*
World Demand	**85.2**	**87.0**	**86.5**	**85.5**	**88.5**	**89.5**	**90.7**	***91.7***	***93.1***	***95.3***	***96.4***	***97.9***	***99.2***	***100.5***
Non-OPEC supply (includes Angola, Ecuador and Indonesia for periods when each country was outside OPEC[1])	**51.3**	**50.5**	**49.6**	**51.4**	**52.7**	**52.8**	**53.3**	***54.5***	***56.6***	***57.8***	***56.5***	***57.4***	***59.6***	***61.3***
Angola supply adjustment[1]	-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	0.0
Ecuador supply adjustment[1]	-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	0.0
Indonesia supply adjustment[2]	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	0.6
Non-OPEC supply (ex. Angola/Ecuador and inc. Indonesia for all periods)	**50.3**	**51.0**	**50.6**	**51.4**	**52.7**	**52.8**	**53.3**	**54.5**	**56.6**	**57.8**	**57.1**	**58.0**	**60.2**	**61.9**
Gabon/E Guinea/Congo supply adjustment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.6	0.6	0.6
OPEC NGLs	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*	*7.0*
Non-OPEC supply plus OPEC NGLs plus Gabon/E Guinea/Congo (ex. Angola/Ecuador and inc. Indonesia for all periods)	**54.6**	**55.3**	**55.1**	**56.5**	**58.2**	**58.7**	**59.7**	**60.6**	**63.0**	**64.7**	**64.2**	**65.5**	**67.8**	**69.5**
Call on OPEC-12[3]	**30.6**	**31.7**	**31.4**	**29.0**	**30.3**	**30.8**	**31.0**	**31.1**	**30.1**	**30.6**	**32.2**	**32.4**	**31.4**	**31.0**

[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: 2006 - 2016: IEA oil market reports; 2017 - 19: Oct 2018 Oil market Report

Global oil demand in 2018 is forecast to be 12.2m 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 further rise of 1.3m b/day in 2019, which would take oil demand to an all-time high of 100.5m 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:

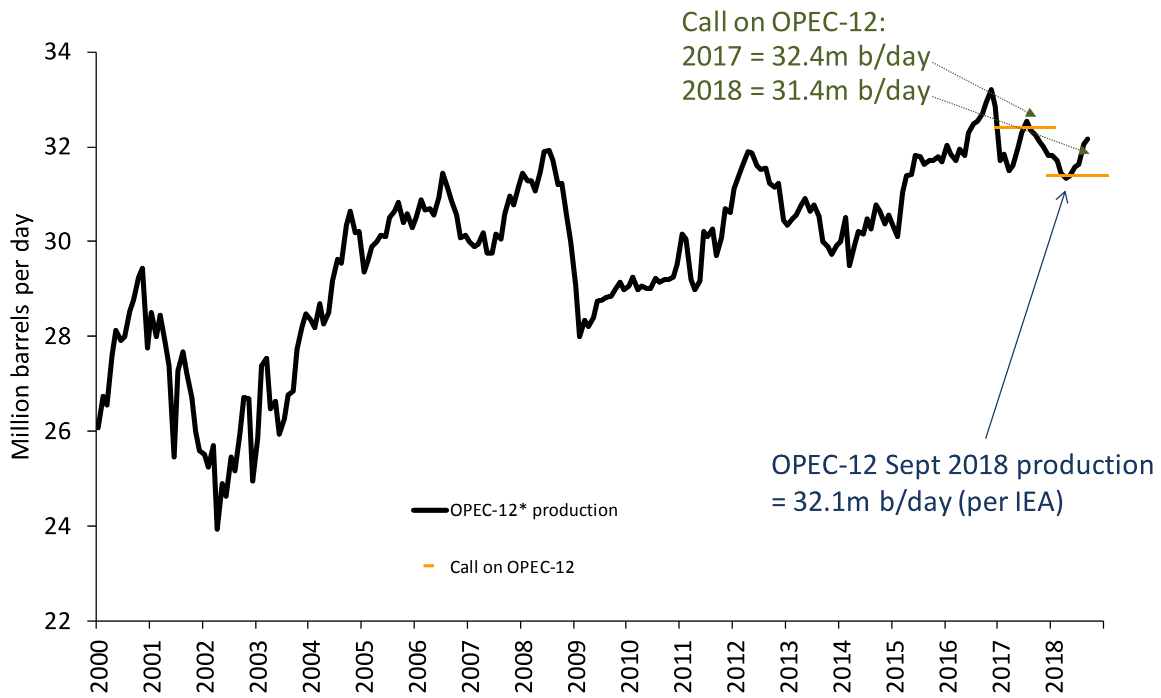
('000 b/day)	31-Dec-10	30-Nov-14	31-Dec-16	31-Oct-18	Current vs Dec 2010 (start of Arab Spring)	Current vs Nov 2014 (OPEC hold mkt share)	Current vs Dec 2016 (OPEC cut production)
Saudi	8,250	9,650	10,480	**10,680**	2,430	1,030	200
Iran	3,700	2,780	3,730	**3,420**	-280	640	-310
Iraq	2,385	3,370	4,630	**4,690**	2,305	1,320	60
UAE	2,310	2,800	3,070	**3,120**	810	320	50
Kuwait	2,300	2,790	2,860	**2,760**	460	-30	-100
Nigeria	2,220	1,970	1,500	**1,820**	-400	-150	320
Venezuela	2,190	2,350	2,080	**1,270**	-920	-1,080	-810
Angola	1,700	1,640	1,670	**1,530**	-170	-110	-140
Libya	1,585	580	630	**1,220**	-365	640	590
Algeria	1,260	1,100	1,110	**1,070**	-190	-30	-40
Qatar	820	650	620	**610**	-210	-40	-10
Ecuador	465	561	550	**520**	55	-41	-30
OPEC-12	**29,185**	**30,241**	**32,930**	**32,710**	**3,525**	**2,469**	**-220**

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 onshore) projects reaching production.

Figure 7: OPEC-12 apparent production vs call on OPEC 2000 – 2018



Source: IEA Oil Market Report (October 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. The agreed cuts came into effect on 1 January 2017, and were initially designed to be kept in place for six months, but were subsequently extended to the end of 2018. Compliance with the cuts was very strong and, after been delayed initially by a variety of temporary factors, inventories started to decline from mid 2017. Having originally been excluded from the cuts, Libya and Nigeria were subsequently included in the quota system.

OPEC showed clear intention to end the production cuts in a manner that was consistent with maintaining a balanced market. And in June 2018, with Brent oil averaging around $75/bl and OPEC compliance to the agreed production cuts running at just over 150%, OPEC met in Vienna. At the conclusion of their meeting, OPEC's headline announcement was "to strive to adhere to the overall conformity level of OPEC-12, down to 100%, as of 1 July 2018". Details were scant but we interpret the announcement as implying an increase in production of around 0.6m b/day. Some non-OPEC members, led by Russia, are expected to increase production as well, taking the potential increase in overall OPEC and non-OPEC volumes potentially as high as 1m b/day for the second half of 2018.

The meeting confirmed that OPEC remain committed to delivering a reasonable oil price to satisfy their own economies but also to incentivise investment in long term projects. 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 since the start of the decade has been dominated by the successful development of shale oil and oil sands in North America (up around 6m b/day between since 2010), implying that the rest of non-OPEC region has barely grown over this 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, enough to see growth sustaining.

Offsetting US onshore shale oil growth, we expect to see non-OPEC supply outside the US weakens, as the queue of large conventional project start-ups slows. 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 lack of supply response 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 1.3m 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 1.0m b/day and OECD demand growth of 0.3m b/day. The components of this non-OECD demand growth can be summarised as follows:

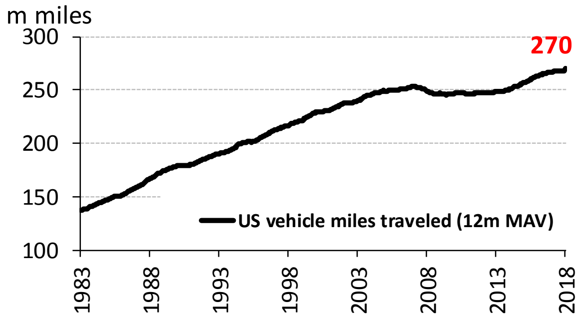
Figure 8: Non-OECD oil demand

m b/day	Demand								Growth						
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018e**	**2019e**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018e**	**2019e**
Asia	21.4	22.1	22.8	24.1	25.0	26.0	26.9	27.8	0.7	0.7	1.3	0.9	1.0	0.9	0.9
Middle East	7.8	7.9	8.4	8.5	8.5	8.5	8.5	8.6	0.1	0.5	0.1	0.0	0.0	0.0	0.1
Latin America	6.4	6.7	6.8	6.7	6.4	6.5	6.4	6.5	0.3	0.1	-0.1	-0.3	0.1	-0.1	0.1
FSU	4.6	4.7	4.66	4.6	4.5	4.5	4.7	4.7	0.1	0.0	-0.1	0.0	0.0	0.2	0.0
Africa	3.8	3.9	3.8	4.2	4.3	4.3	4.3	4.4	0.1	-0.1	0.4	0.1	0.0	0.0	0.1
Europe	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**44.7**	**46.0**	**47.2**	**48.7**	**49.4**	**50.5**	**51.6**	**52.8**	**1.3**	**1.2**	**1.6**	**0.7**	**1.1**	**1.0**	**1.2**

Source: IEA Oil Market Report (October 2018)

Asia has settled down into a steady pattern of growth since 2010, and accounts for much of expected growth in 2018. 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 a $60/bl oil price, the world oil bill as a percentage of GDP is around 2.5% and this will still be a stimulant of multi-year demand growth. If oil prices move 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 flatter picture in the OECD more than offset by strong growth in the non-OECD area. Flatter OECD demand reflects improving oil efficiency over time, 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. 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 potoprice 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 2017.

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	64
Brent	30	32	35	46	64	75	82	103	67	84	115	112	108	99	52	45	54	68
Brent/WTI (12m MAV)	**30**	**33**	**37**	**48**	**65**	**75**	**82**	**104**	**68**	**84**	**107**	**103**	**103**	**96**	**51**	**45**	**53**	**66**
Brent/WTI y-on-y change (%)		8%	12%	30%	37%	15%	9%	26%	-35%	24%	27%	-4%	0%	-7%	-47%	-11%	17%	26%
Brent/WTI (5yr MAV)	30	25	32	37	42	51	61	75	79	82	89	93	93	99	92	80	69	62

We expect oil to trade in a $60-75/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 $70/bl would represent 3.0% of 2018 Global GDP, 12% 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.

Natural gas market

US gas demand

On the demand side for the US, 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. 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	2019E
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	22.1	21.5
Power generation	18.7	18.2	18.8	20.2	20.8	24.9	22.3	22.3	26.5	27.3	25.3	28.5	28.5
Industrial	18.2	18.2	16.9	18.5	19.0	19.7	20.3	20.9	20.6	21.1	21.6	22.8	23.2
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	7.8
LNG exports	-	-	-	-	-	-	-	-	0.1	1.0	2.6	3.4	6.7
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	6.8	6.8
Total demand	**65.4**	**66.2**	**65.6**	**68.8**	**71.3**	**74.3**	**76.1**	**77.0**	**80.0**	**82.6**	**83.1**	**90.6**	**94.5**
Demand growth	**4.0**	**0.8**	**- 0.6**	**3.2**	**2.5**	**3.0**	**1.8**	**0.9**	**3.0**	**2.6**	**0.5**	**7.5**	**3.9**

Source: EIA; Simmons; Guinness estimates

Total gas demand in 2018 (including Canadian, Mexican and LNG exports) is expected to be around 90.6 Bcf/day, up by 7.5 Bcf/day (9.0%) versus 2017 and 10.8 Bcf/day (13.5%) higher than the 5 year average. The biggest contributors to the growth in demand in 2018 will be power generation (hot summer and start-up of numerous gas plants increasing gas' share over coal), industrial demand (US GDP growth and petrochemical plant start-ups), and LNGS exports (opening of new export terminals).

We expect US demand in 2019, assuming prices remain around $3/mcf, to exhibit further strong growth of around 4 Bcf/day. Normalised weather would keep a cap on power generation demand, but there should be a surge in LNG exports (c.3 Bcf/day), as a wave of new export terminals come into service. The table below shows the scheduled start-up of terminals, with 4.3 Bcf/day of capacity coming in 2019.

Terminal	Location	2015	2016	2017	2018E	2019E	2020E
Cameron 1-2	LA					1.4	
Cameron 3	LA						0.7
Corpus Christi 1-2	TX					1.3	
Cove Point 1	MD				0.8		
Elba Island 1-6	GA				0.2		
Elba Island 7-10	GA					0.2	
Sabine Pass 1-2	LA						
Sabine Pass 3-4	LA	0.1	1.0	1.3			
Sabine Pass 5	LA					0.7	
Freeport 1	TX					0.7	
Freeport 2-3	TX						1.4
Incremental exports		**0.1**	**1.0**	**1.3**	**1.0**	**4.3**	**2.1**
Total US LNG exports		**0.1**	**1.1**	**2.4**	**3.4**	**7.7**	**9.8**

Source: EIA; Simmons

Looking further ahead, 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 as new pollution standards have 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.

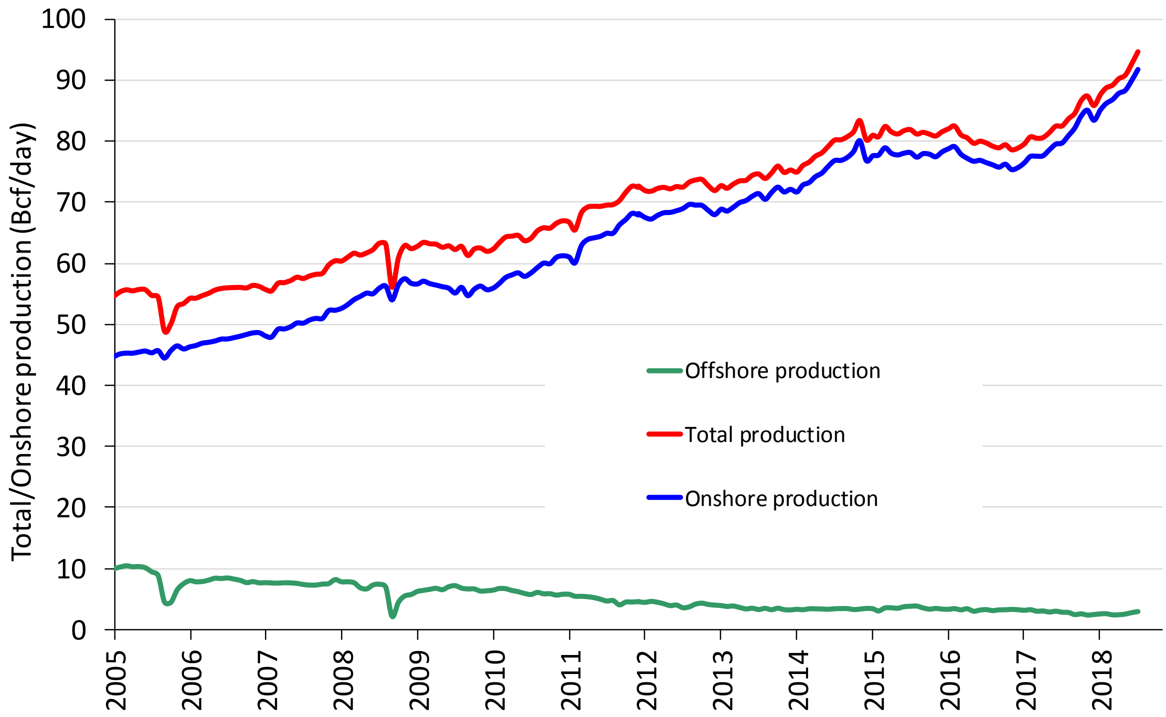
The supply side fundamentals for natural gas in the US are driven by 3 main moving parts: onshore and offshore domestic production, and pipeline imports of gas from Canada. Of these, onshore supply is the biggest component, making up over 85% of total supply.

Bcf/day	2007	2008	*2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018E	2019E
US natural gas supply:													
US onshore	45.1	48.8	49.8	52.2	57.7	61.5	62.7	67.5	70.6	70.0	71.1	79.2	84.8
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	2.5	2.1	2.0
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	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	0.3	0.3
Total supply	**65.5**	**66.1**	**66.9**	**68.8**	**72.2**	**74.5**	**74.4**	**78.5**	**81.8**	**81.8**	**81.9**	**89.6**	**95.1**
Supply growth	**3.2**	**0.6**	**0.8**	**1.9**	**3.4**	**2.3**	**- 0.1**	**4.1**	**3.3**	**-**	**0.1**	**7.7**	**5.5**
(Supply)/demand balance	**- 0.1**	**0.1**	**- 1.3**	**-**	**- 0.9**	**- 0.2**	**1.7**	**- 1.5**	**- 1.8**	**0.8**	**1.2**	**1.0**	**- 0.6**

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 193 at the end of October 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 91.7 Bcf/day, over 50% 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 (August 2018 published in October 2018)

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.

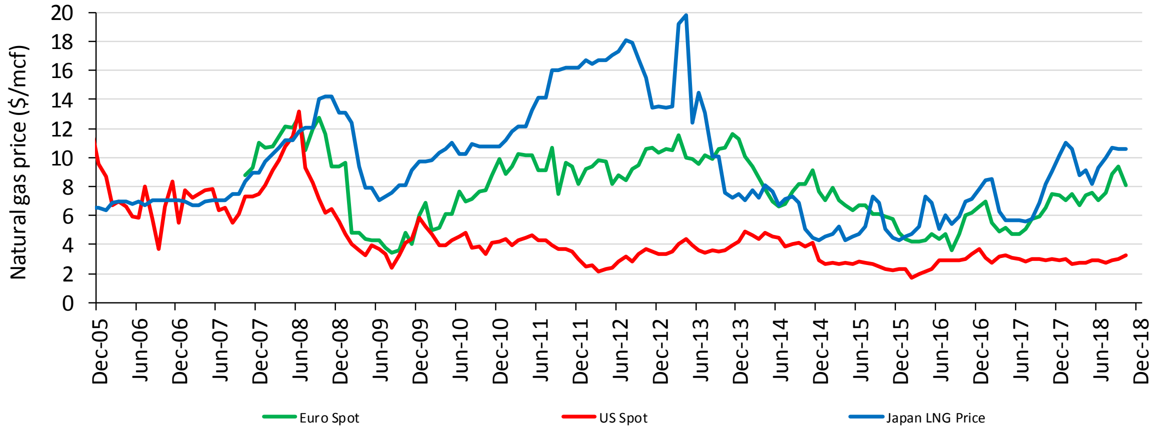
Associated gas production declined in 2016 with the fall of shale oil production, but as US oil supply now growing again, so associated gas production is also picking up. Generally, we expect to see rates of around 2-3 Bcf/day of associated gas per 1m b/day of oil production.

The Marcellus/Utica region, which includes the largest producing gas field in the US and the surrounding region, will reach production of around 29 Bcf/day in 2018, with growth accelerating this year as infrastructure capacity expands. Further growth in region is likely over the next couple of years, supported by a small increase from legacy gas fields, which have reversed the decline seen for much of the earlier part of this decade.

Overall, if the price remains in the $2.50-$3.50/mcf range, we expect a significant jump in onshore gas supply in 2019, up by around 5 Bcf/day versus 2018.

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.$8/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 $10/mcf as Chinese gas demand strengthens. The implied economics for US LNG exports into Europe and Asia are attractive at these levels.



Source: Bloomberg (November 2018)

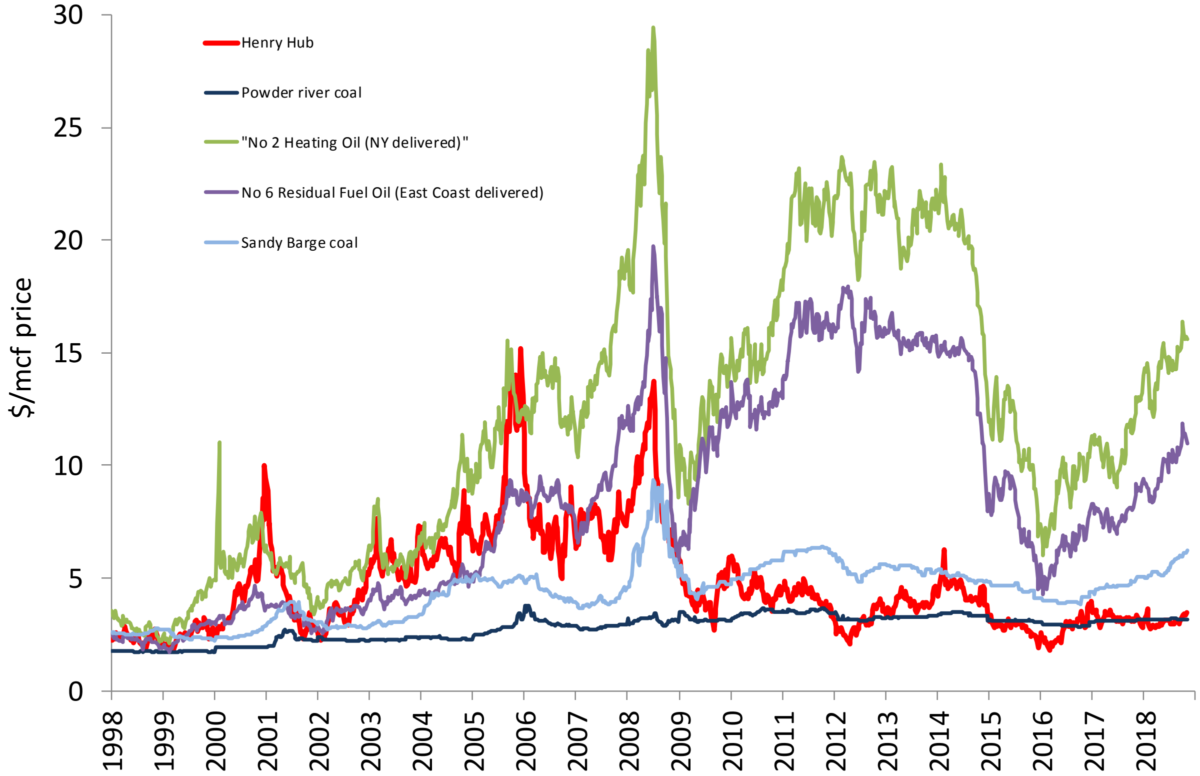
Relationship with oil and coal

The oil/gas price ratio ($ per bbl WTI/$ per mcf Henry Hub) of around 19x at the end of October 2018 continues well outside the long-term ratio of c.10x.

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 (November 2018)

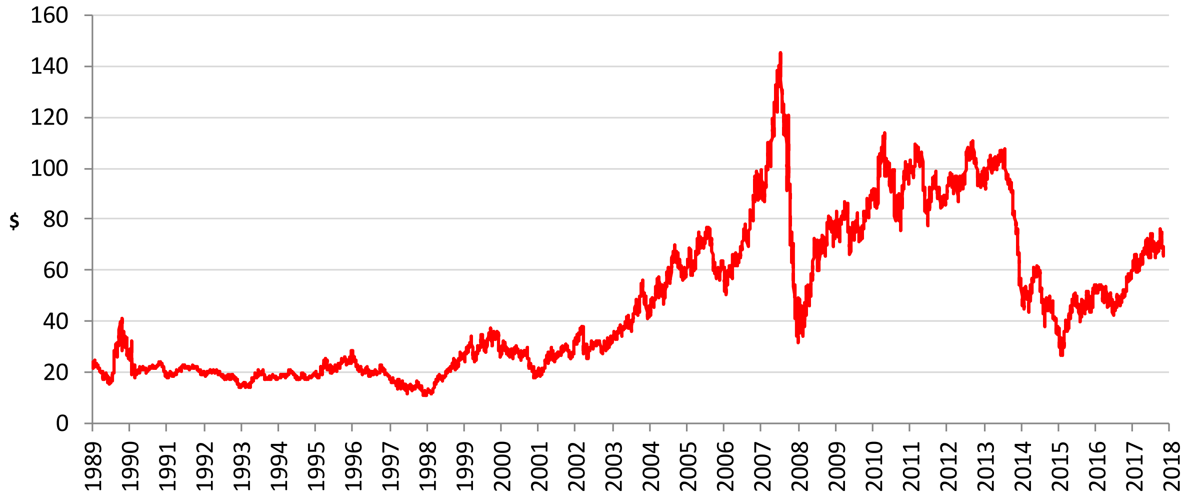
Conclusions about US natural gas

Bcf/day	2007	2008	*2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018E	2019E
Total demand	65.4	66.2	65.6	68.8	71.3	74.3	76.1	77.0	80.0	82.6	83.1	90.6	94.5
Demand growth	4.0	0.8	- 0.6	3.2	2.5	3.0	1.8	0.9	3.0	2.6	0.5	7.5	3.9
Total supply	65.5	66.1	66.9	68.8	72.2	74.5	74.4	78.5	81.8	81.8	81.9	89.6	95.1
Supply growth	3.2	0.6	0.8	1.9	3.4	2.3	- 0.1	4.1	3.3	-	0.1	7.7	5.5
(Supply)/demand balance	- 0.1	0.1	- 1.3	-	- 0.9	- 0.2	1.7	- 1.5	- 1.8	0.8	1.2	1.0	- 0.6

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. 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/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 $) since 1989.



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.

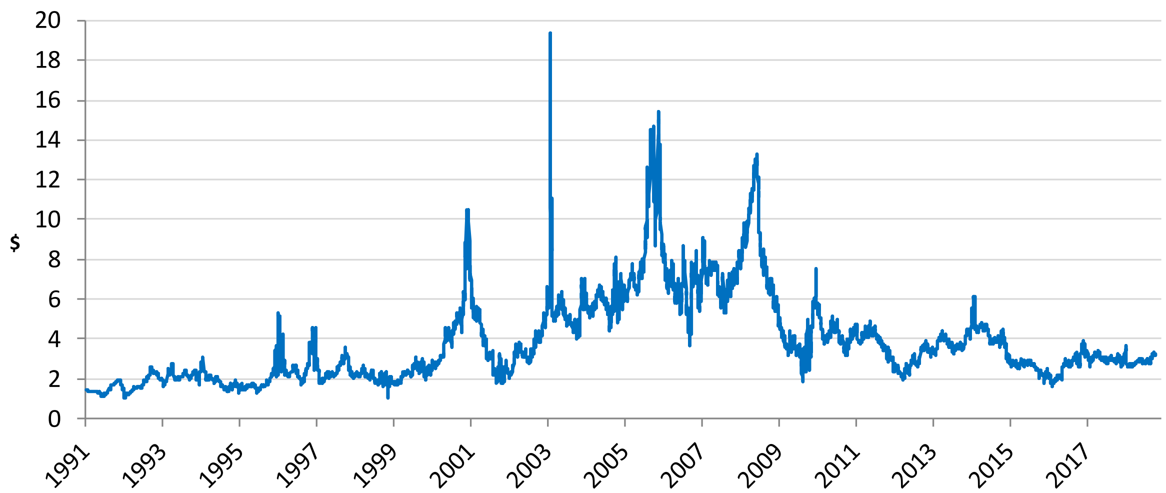
Continued expectations of a supply crunch by the end of the decade, coupled with increased speculative activity in oil markets, contributed to the oil price surging past $90 in the final months of 2007 and as high as $147 by the middle of 2008. This spike was brought to an abrupt end by the collapse 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.

2014 marked the end of the oil cycle that started in the early 2000s. Ten years of high prices catalysed a wall of new non-OPEC supply, sufficient that OPEC saw no choice but to stop supporting price and re-set the investment cycle. Oil prices found a bottom in 2016 (as a result of OPEC cutting production again), but its recovery was capped by the volume of new supply still coming into the market from projects sanctioned pre the 2014 price crash.

Today, strong global demand growth, underinvestment in OPEC states outside the Arabian Gulf, and a slowdown in non-OPEC growth have combined to set up the new oil cycle, with prices averaging over $70/bl once again.

Figure 13: North American gas price since 1991 (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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