THE GUINNESS GLOBAL ENERGY REPORT

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

GUINNESS GLOBAL ENERGY FUND

Fund size: $324m (30.4.17)

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

HIGHLIGHTS FOR APRIL

OIL

Brent and WTI down; OECD inventories declining, offset by strong US supply data

Brent and WTI oil were down over the month; WTI declined from $51 to $49/bl, whilst Brent fell from $53 to $52/bl. OECD inventories declined in March, and look to have declined in April, though imports of oil into the US remain stubbornly high. US onshore production is growing again, supported by strong first quarter results.

NATURAL GAS

US gas prices up slightly, production also up

Henry Hub prices rose in April, up from $3.19 to $3.28/mcf. Weather adjusted, the US gas market remained undersupplied, which caused gas inventories to tighten, though production is starting to grow again (supported by associated gas from shale oil). European gas prices (c.$5/mcf) were also weakened by warm weather, whilst Asian gas prices (c.$6/mcf) were down.

EQUITIES

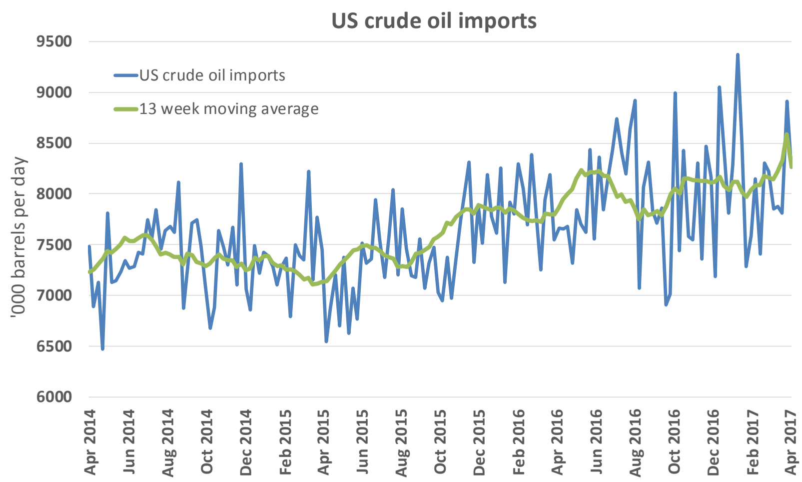
Energy underperforms the broad market

The MSCI World Energy Index fell in April by 2.3%, underperforming the MSCI World Index which rose by 1.5% (all in US dollar terms). Since the start of the year, the MSCI Energy Index is down by 6.9%, which compares to the MSCI World up by 8.2%.

CHART OF THE MONTH

US oil imports higher in April than Q4 2016, despite OPEC action

Imports of crude oil into the US have remained high in April, despite good compliance from OPEC with with their programme of production cuts. Nevertheless, US inventories of crude oil and refined products have declined in March and April, albeit by less than the market was hoping. Imports have remained elevated thanks partly to oil being pushed out of floating storage, an effect that is now dimishing.



Source: DoE; Guinness Asset Management

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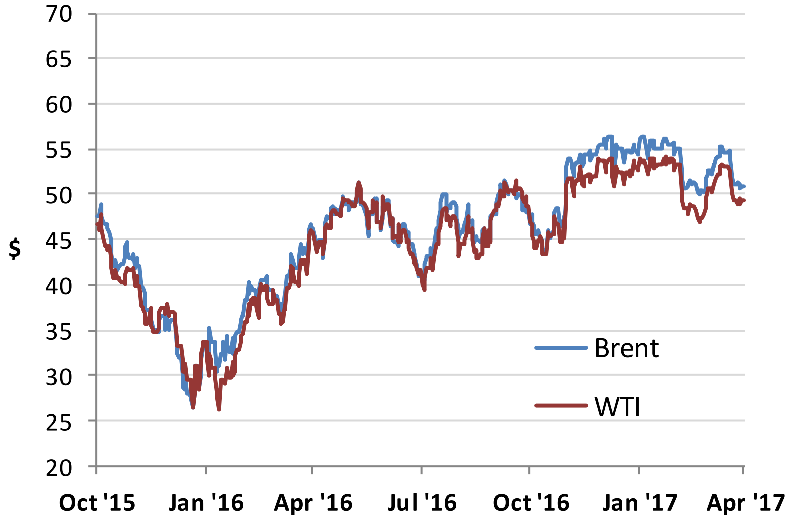
1. APRIL IN REVIEW

i) Oil market

Figure 1: Oil price (WTI and Brent $/barrel) 18 months October 31 2015 to April 30 2017



Source: Bloomberg LP

The West Texas Intermediate (WTI) oil price started April at $50.6/bl and traded higher for the first half of the month, reaching $53.2 on April 13, before declining steadily to close at $49.3/bl. WTI has averaged $51.7/bl so far in 2017, having averaged $43.4 in 2016, $48.7 in 2015 and $93.1 in 2014.

Brent oil traded in a similar way, opening April at $52.8/bl, rising mid-month to $56.2, and closing at $51.7/bl. The gap between the WTI and Brent benchmark oil prices was broadly unchanged at the end of the month, at around $2. The WTI-Brent spread averaged $1.7/bl during 2016, having been well over $10/bl at times since 2011.

Factors which weakened WTI and Brent oil prices in April:

- **US onshore oil production growing**
  At the start of May, the EIA reported that US onshore oil production rose by 218,000 b/day during February 2017. This is a significant increase and, whilst the size of the increase was abnormally high (offsetting weaker data in December 2016 and January 2017), it nevertheless indicates that the US oil system is returning to better health. We expect the US onshore production in 2017 to average around 300,000-400,000 b/day higher than 2016.

- **US oil drilling rig count increasing**
  The Baker Hughes oil directed rig count continued its recovery during the month, increasing from 662 at the end of March to 697 at the end of April, up by a total of 35 rigs over the month. The rig count reached a low of 316 rigs in May 2016, having peaked in October 2014 at 1,609 rigs.

Factors which strengthened WTI and Brent oil prices in April:

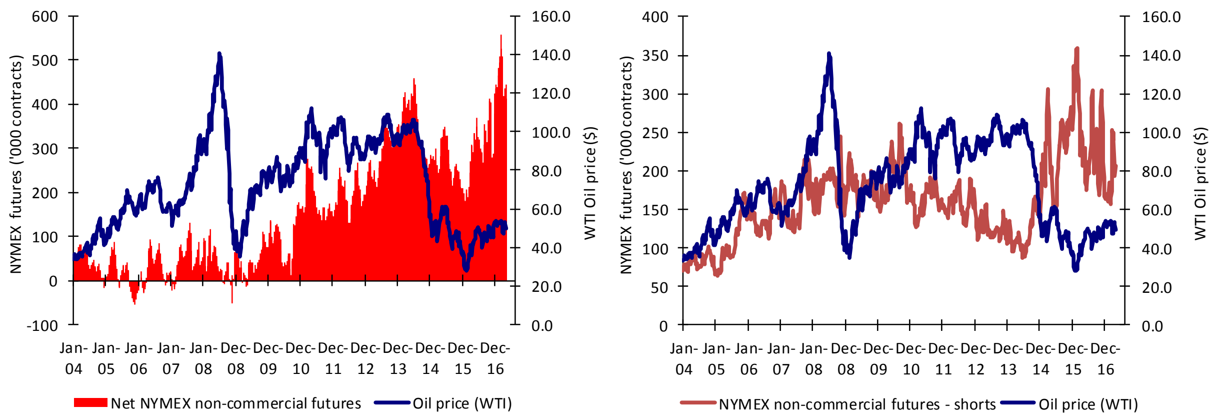
- **OECD oil inventories declining more than seasonal norm**
  The latest data for OECD inventories, for March, showed a draw of 32m barrels versus a 10 year average build of 2m barrels, contributing to the picture that oil markets are now tightening, after a slow start to the year. OECD inventory data for April is not yet available, but we expect another draw (versus seasonal build). Weekly US inventory data is supportive of this forecast, with total oil and product inventories down by 8m barrels compared to a 5 year average build of 7m barrels. Saudi watch the state of OECD inventories closely, and are attempting to manage them back to average levels.

- **Signs of continued good OPEC compliance with announced January 2017 production quota cuts**
  Actual production data for April 2017 will not be available until later this month but, at the time of writing, indications are that OPEC is maintaining good levels of compliance with its January 1 2017 production quotas. March production for the members of OPEC participating in the cut (Libya and Nigeria are excluded) was reported by the IEA at at 29.6m b/day, versus target production of 29.8m b/day. We expect similar production to be reported for April. Attention in April also started to turn towards OPEC's next scheduled meeting, on May 25. The majority view is that OPEC will roll over their production cuts for the rest of 2017. Non-OPEC production cuts are more difficult to track but appear to running at around 0.3m b/day, so around half of the agreed 0.6m b/day reduction.

Speculative and investment flows

The New York Mercantile Exchange (NYMEX) net non-commercial crude oil futures open position (WTI) grew in April, ending the month at 412,000 contracts long versus 398,000 contracts long at the end of March. Typically there is a positive correlation between the movement in net position and movement in the oil price. The net short position declined from 250,000 contracts to 207,000 contracts.

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

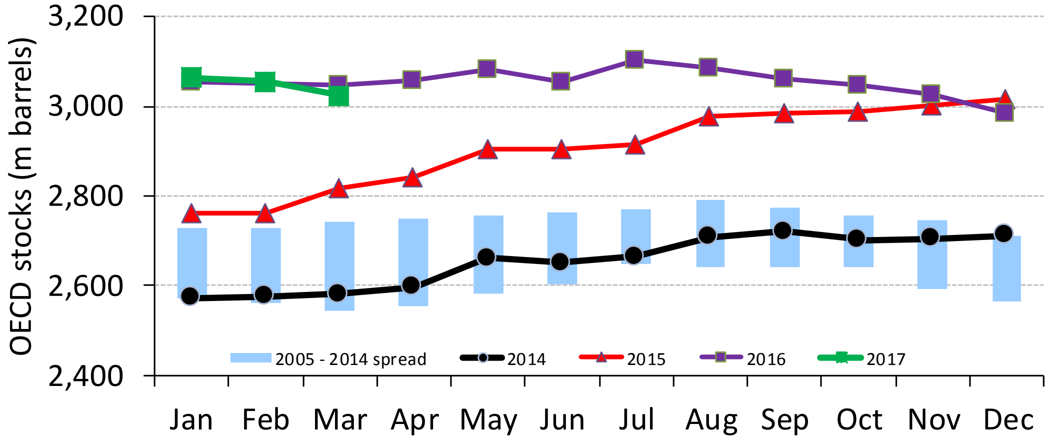


Source: Bloomberg LP/NYMEX/ICE (2017)

OECD stocks

OECD total product and crude inventories at the end of March (the latest data point available) were estimated by the IEA to be 3,023m barrels, down by 32m barrels versus the previous month. 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 are still considerably above the top of the 10 year historic range, and we expect them to continue to tighten over the next few months.

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



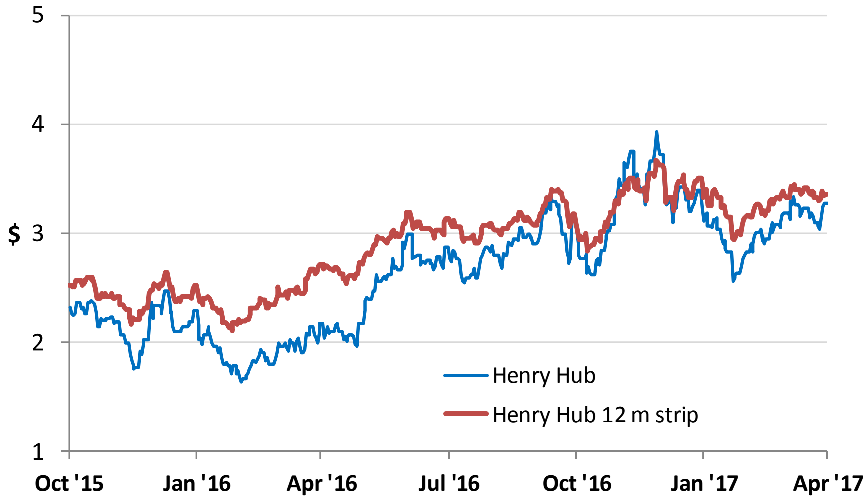
Source: IEA Oil Market Reports (April 2017 and older)

ii) Natural gas market

The US natural gas price (Henry Hub front month) opened April at $3.19 per Mcf (1,000 cubic feet). The price traded between $3.04 and $3.33 during the month, ending at $3.28. The spot gas price averaged $2.55 in 2016 which compares to an average gas price of $2.61/mcf in 2015 and $4.26 in 2014 (assisted by a very cold 2013/14 US winter). The price averaged $3.72 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 traded higher in April, up from $3.33 to $3.35. The strip price averaged $2.84 in 2016, having averaged $2.86 in 2015, $4.18 in 2014, $3.92 in 2013, $3.28 in 2012, $4.35 in 2011, $4.86 in 2010 and $5.25 in 2009.

Figure 4: Henry Hub Gas spot price and 12m strip ($/Mcf) October 31 2015 to April 30 2017



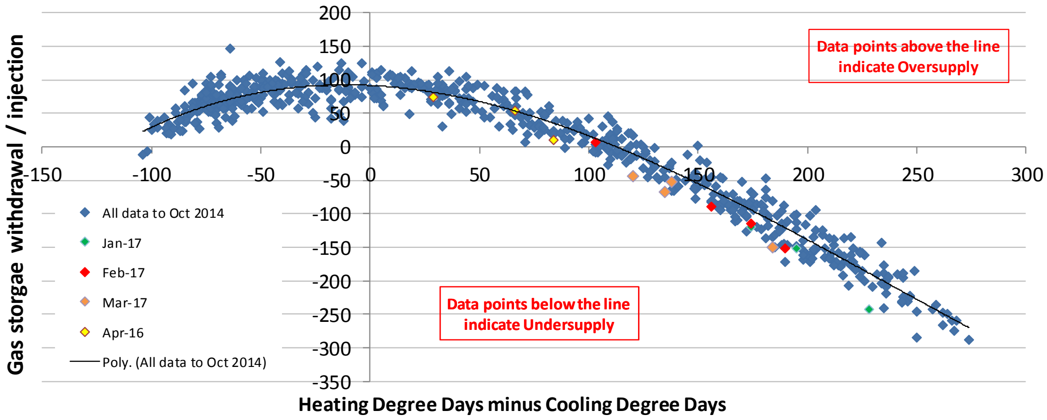
Source: Bloomberg LP

Factors which strengthened the US gas price in April included:

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

below). 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 April included:

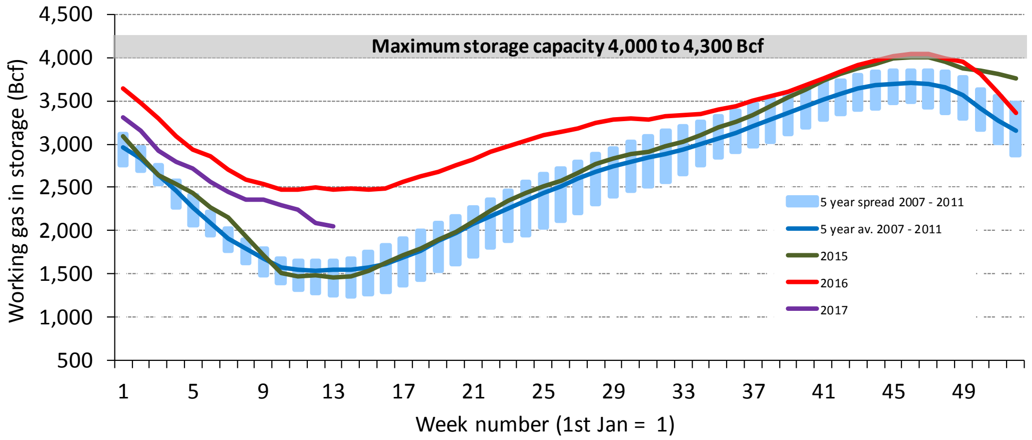
- **US shale oil production returning to growth, bringing associated gas**
  US onshore oil production grew rapidly in February 2017, and is expected to continue to grow throughout the year, heralding the return of associated gas production. If US onshore oil supply is up, on average, by 0.3-0.4m b/day this year versus 2016, we would expect around 1 Bcf/day of associated gas growth.

- **Stronger US onshore natural gas production**
  Onshore US natural gas production averaged 76.8 Bcf/day in February 2017, up by 1.9 Bcf/day on the level reported for January 2017. Production from Texas rebounded particularly strongly, with notable gains in Oklahoma and the Marcellus also. We expect US onshore natural gas production to be up on average by around 2 Bcf/day in 2017 versus 2016.

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 at 30th April 2017 were reported by the EIA to be 2,256 Bcf. The 205 Bcf injection in inventories during April was just greater than the ten year average of 199 Bcf, leaving inventories are still well above the top of the five year range.

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



Source: Bloomberg; EIA (May 2017)

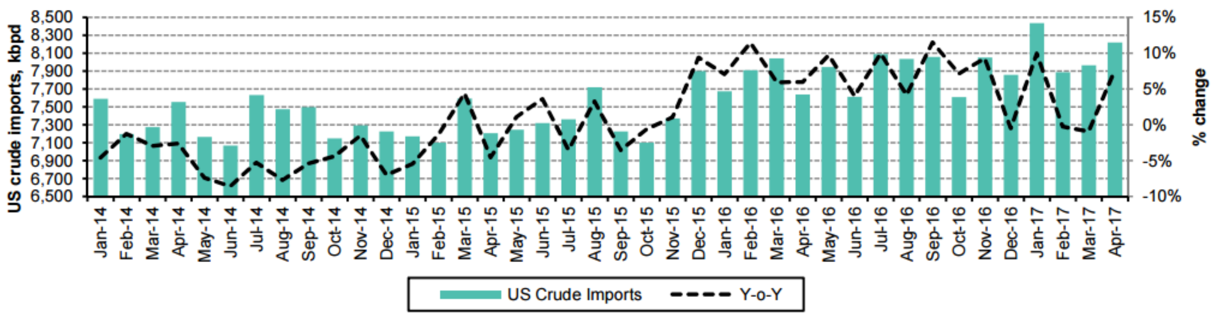
2. MANAGER'S COMMENTS

Oil prices have weakened since mid-April, with Brent and WTI moving in the $45-50/bbl range, having spent much of the first quarter of 2017 in the $50-55 range. Why have we seen this weakness? On one level, day-to-day moves in the commodity are driven by short-term technical factors. Over the last couple of days, for example, we have seen "cross correlation-driven" selling as iron ore and copper prices decline (coming from rising fears around China growth following a sustained bout of tightening, plus questions over Indian growth). We've also seen technical trading levels breached, bringing CTA (Commodity Trading Advisor) selling and a likely sharp decline in the NYMEX net non-commercial position as long positions are liquidated below the Brent support level of $50/bbl.

In a sense, though, these short-term technical factors are noise: amplifying the volatility of the oil price but masking the reality that the market is trying to find a 'level' which creates balance in the market. We continue to believe this is something in the $50s /bbl for 2017, trending higher on a 2-3 year view as the call on US shale oil supply likely grows.

Focussing on the shorter-term fundamentals (as opposed to technicals), the market appears to be losing patience as oil inventories remain high, despite strong compliance with OPEC production cuts that were initiated on 1 January. According to the IEA, OECD oil and product inventories during the first quarter of 2017 actually grew by 39m barrels, greater than the 15m barrel rise seen on average over the last 10 years. Indeed, we can see that imports of crude oil into the US in April 2017 are still running at a higher level that Q4 2016, despite the OPEC cuts:

US crude imports (monthly, k b/day) 2014-2017



Source: Bernstein; EIA (May 2017)

We believe the slowness of inventories to decline can be attributed to a handful of factors, most of which are temporary:

- The lag effect in the time taken for OPEC production cuts to translate into lower imports in consuming countries. Including loading and unloading, the average VLCC (very large crude carrier) takes around 65 days to deliver oil from the Middle East to the US and Asia. OPEC production surged in 4Q 2016, and this has been finding its way into the market during the start of 2017.
- Notwithstanding the lag effect described above, OPEC production cuts of >1m b/day have not yet resulted in a proportionate decline in oil exports. It is difficult to pinpoint the exact reasons for this (domestic OPEC refinery maintenance has perhaps ramped up?), but we can point to a drawdown of oil inventories in Iran and Saudi Arabia for part of the answer. Iran, for example, has reduced its floating inventories from 25m barrels in December 2016 to 5m barrels in April 2017, pushing an additional 20m barrels into the market.

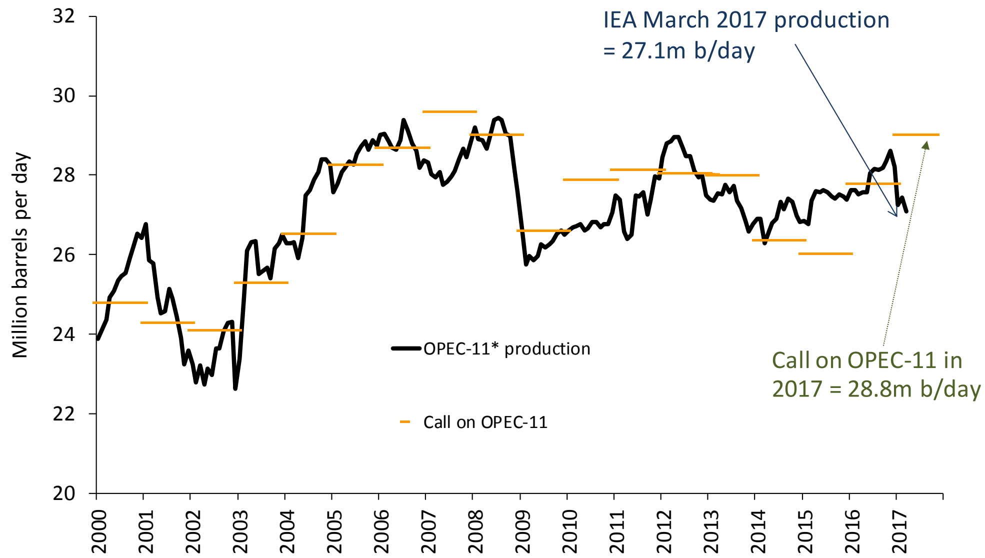
According to the IEA, floating storage has also been reduced in the Caribbean and in South Africa bringing the total reduction in global floating storage to about 40mn bls in the first quarter.

- Warmer winter weather dampening demand. Whilst global oil demand growth in 2017 is still expected to grow by 1.3m b/day, Q1 demand was softened by a warm end to winter in the US, reducing the call on heating oil.

It is worth making clear that despite the overall build in OECD inventories during the first quarter of 2017, recent weekly data points indicate that inventories are now in meaningful decline. OECD inventories fell in March by 32m barrels (vs a 10 year average build of 2m, indicating a market undersupplied by 1.1m barrels/day. We await OECD inventory data for April, but we know that the US portion (crude oil and refined products) declined by 8m barrels over the month, compared to a normal build of 7m barrels.

Assuming that OPEC sustain their production cuts into the second half of 2017, we see the deficit between OPEC production and the fundamental 'call on OPEC' (i.e. what they need to produce to keep the market balanced) at over 1.5m b/day. Whilst we in the financial community have a tendency to simplify the month-to-month complexities of a physical system such as the oil market, we would expect the impact of temporary leads and lags to fade, and to see this deficit materialise over the rest of the year.

OPEC-11 apparent production vs call on OPEC 2000 – 2017



Source: IEA Oil Market Report (April 2017 and prior); Guinness estimates

In its efforts to manage the oil market, OPEC's biggest challenge remains the return of growth to US onshore production, and whether this growth will swamp OPEC's production cut and push the market back to oversupply. Looking at the behaviour of US onshore E&Ps, it is clear that animal spirits have returned to the sector, as (partially) repaired balance sheets and a lower cost of supply allows them to accelerate drilling. Efficiency gains, particularly in the Permian basin, continue to be reported but cost inflation is reappearing as an offsetting factor. We would now expect to see US production up by nearly 1m b/day from year-end 2016 to year-end 2017 (translating into average 2017 production being c.0.3-0.4m b/day higher than 2016). However, there is a danger of extrapolating the return to growth too far, and forgetting that lower oil prices will once again impact on CAPEX budgets and the rig count. For all the talk of US shale companies making successful returns below $50/bbl, we note that very little producer hedging has been carried out this year below $53/bbl (WTI).

In the shorter-term, Saudi will want a better oil price environment for the IPO of Saudi Aramco in 2018. Beyond that, Saudi and OPEC will be hoping that the dearth of new project sanctions and increasing decline rates on existing fields means that non-OPEC (ex US) oil production will decline into the end of the decade, increasing the call on the US and OPEC.

On the demand side, an oil price of around $50/bl represents 2% of world GDP, well below the long term average 'oil bill' that the world has paid over the past 40 years, and provides good support to demand growth as we look forward. Virtually all of the growth will be delivered by the non-OECD, as its population of 6.5 billion aspire to catch up with the consumption standards of the 1 billion living in the OECD.

Energy sector return on capital employed (ROCE) at the start of 2017 remains close to historic lows but is likely to recover because of efficiency gains, cost control and lower reinvestment. The valuation of energy equities is strongly correlated to ROCE and, if the relationship holds true, energy equity valuation should improve as ROCE improves. Company financial results for the first quarter of 2017 indicate improvements in underlying profitability and cash flow generation for the oil industry as a whole and give confidence that underlying ROCE is trending upwards.

The valuation sensitivity work that we regularly perform tells us that energy equities are today discounting an oil price (into perpetuity) of around $50/barrel. This is just above the current spot and five year forward prices for Brent and WTI. If you believe, as we do, that a recovery in the oil price to well over $50/bl is likely, or that return on capital will normalise (or both), our sensitivity work shows upside across the energy complex of 50+%.

3. PERFORMANCE Guinness Global Energy Fund

The main index of oil and gas equities, the MSCI World Energy Index, was down 2.3% in April, while the MSCI World Index rose by 1.5%. The Fund was down by 2.2% (class E) in the month, outperforming the MSCI World Energy Index by 0.1% (all in US dollar terms).

Within the Fund, April's strongest performers were OMV, Tullow, Soco, Sunpower and JA Solar, while the weakest performers were QEP, Carrizo, Helix, Unit and Schlumberger.

Performance (in USD) **30/04/2017**

Annualised

% returns	1 year	3 years	5 years	10 years	1999 to date
Guinness Global Energy	-1.6	-15.1	-3.8	-1.1	10.1
MSCI World Energy Index	3.9	-8.6	-0.6	0.9	6.8

Calendar year

% returns	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007
Guinness Global Energy	-9.9	27.9	-27.6	-19.1	24.4	3.0	-13.6	15.3	61.8	-48.2	37.6
MSCI World Energy Index	-6.9	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 April we rebalanced the portfolio but made no stock switches.

Sector Breakdown

The following table shows the asset allocation of the Fund at **April 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 2007*	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 Apr 2017
Oil & Gas	**103.5**	**96.4**	**98.2**	***93.3***	***97.9***	***97.3***	***93.7***	***93.7***	***95.1***	***96.7***	***97.7***
Integrated	40.3	41.6	35.9	33.0	30.9	30.4	29.2	27.0	30.4	32.5	29.6
Integrated – Can & Em Mkts	25.9	12.1	11.9	8.2	8.8	8.4	9.4	10.3	11.1	14.3	14.4
Exploration & production	25.8	28.7	32.8	37.1	41.1	40.3	35.4	36.2	36.5	35.4	36.6
Oil & Gas Storage & Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6
Drilling	8.1	5.2	8.5	6.1	5.9	7.1	6.4	3.3	1.5	2.2	1.7
Equipment & services	3.4	6.4	5.9	5.4	6.1	7.4	9.8	13.4	11.4	8.6	8.3
Refining and marketing	0.0	2.4	3.2	3.5	5.1	3.7	3.5	3.5	4.2	3.7	3.5
Solar	**0.0**	**0.0**	**0.0**	**3.2**	**1.3**	**1.2**	**2.6**	**3.7**	**4.7**	**0.9**	**1.1**
Coal & consumables	**2.5**	**2.3**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Construction & engineering	**0.0**	**0.4**	**0.3**	**0.3**	**0.4**	**0.6**	**1.0**	**0.0**	**0.0**	**0.0**	**0.0**
Cash	**-6.0**	**0.9**	**1.5**	**3.2**	**0.4**	**0.9**	**2.7**	**2.6**	**0.2**	**2.4**	**1.2**
Total	**100.0**	**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 April 30 2017 was on a price to earnings ratio (P/E) for 2017 of 20.7x versus the S&P 500 Index at 18.6x as set out in the table. (Based on S&P 500 'operating' earnings per share estimates of $83.8 for 2010, $96.4 for 2011, $96.8 for 2012, $107.3 for 2013, $113.0 for 2014, $100.4 for 2015; $106.0 for 2016 and $129.5 for 2017). This is shown in the following table:

	2010	2011	2012	2013	2014	2015	2016	2017
Guinness Global Energy Fund P/E	8.9	7.5	7.8	8.8	9.6	20.2	33.7	20.7
S&P 500 P/E	28.7	24.9	24.8	22.4	21.1	24.0	22.7	18.6
Premium (+) / Discount (-)	*-69%*	*-70%*	*-68%*	*-61%*	*-55%*	*-16%*	*49%*	*11%*
Average oil price (WTI $/bbl)	80	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 April 30 2017 the median P/E ratios of this group were 28.3x/15.7x 2016/2017 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.36%) 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, Carrizo and QEP Resources), with four other names (Apache, Occidental, ConocoPhillips, Noble) having significant 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 4.6x 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 11% of the portfolio. The stocks we own are split between those which focus their activities in North America (land driller Unit Corp) and those which operate in the US and internationally (Helix, Halliburton and Schlumberger).

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

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

Portfolio at March 31st 2017 (for compliance reasons disclosed one month in arrears)

Guinness Global Energy Fund 31 March 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	3.57	20.9	11.5	8.0	8.7	9.7	11.2	29.5	77.4	23.6	17.8
Royal Dutch Shell PLC	EUR	NL	3.56	12.0	8.5	6.3	6.3	8.2	7.3	15.4	25.4	14.9	12.0
BP PLC	GBP	GB	3.59	7.3	5.1	5.0	6.3	7.8	9.3	16.3	31.2	16.0	12.8
Total SA	EUR	FR	3.63	13.3	10.3	9.2	8.8	9.8	10.0	12.8	15.1	12.1	10.5
ENI SpA	EUR	IT	3.61	10.8	8.2	7.8	7.6	12.2	14.2	66.5	nm	24.0	16.3
Statoil ASA	NOK	NO	3.60	9.8	7.4	6.4	5.7	7.0	9.8	23.9	121.1	16.4	13.3
Hess Corp	USD	US	3.50	25.2	9.3	8.0	8.2	8.4	11.6	nm	nm	nm	nm
OMV AG	EUR	AT	3.63	14.8	9.2	11.6	8.1	9.9	12.2	10.9	11.2	13.1	11.9
			28.69										
Integrated / Oil & Gas E&P - Canada													
Suncor Energy Inc	CAD	CA	3.53	38.7	25.7	11.4	12.7	12.8	12.7	36.3	nm	22.8	19.9
Canadian Natural Resources Ltd	CAD	CA	3.62	18.1	17.9	18.8	27.4	19.4	12.6	313.2	nm	25.6	16.2
Imperial Oil	CAD	CA	3.52	20.4	17.7	11.0	9.8	12.6	10.6	22.8	67.3	16.4	15.4
			10.68										
Integrated Oil & Gas - Emerging market													
PetroChina Co Ltd	HKD	HK	3.54	8.5	6.8	6.7	7.8	8.6	8.5	26.3	103.1	19.4	12.8
Gazprom OAO	USD	RU	3.52	4.6	3.6	2.4	2.5	2.4	3.6	2.6	3.4	3.7	3.1
			7.06										
Oil & Gas E&P													
Occidental Petroleum Corp	USD	US	3.56	17.0	11.2	7.6	9.1	9.1	10.9	381.7	nm	59.8	34.8
ConocoPhillips	USD	US	3.90	13.8	8.4	5.9	8.7	8.9	9.4	nm	nm	69.2	27.4
Apache Corp	USD	US	3.52	9.2	5.5	4.3	5.4	6.3	9.2	nm	nm	43.2	25.4
Devon Energy Corp	USD	US	3.66	12.8	7.0	6.9	12.9	9.8	8.1	16.9	nm	22.0	15.1
Noble Energy Inc	USD	US	3.53	20.3	16.6	13.1	15.0	11.1	14.7	602.5	nm	nm	99.2
QEP Resources Inc	USD	US	2.11	nm	9.2	7.8	10.2	9.1	9.0	nm	nm	nm	nm
Newfield Exploration Co	USD	US	3.64	7.3	8.0	9.1	15.2	20.5	20.0	50.9	34.3	17.6	14.1
Carrizo Oil & Gas Inc	USD	US	2.14	19.5	22.5	27.9	19.7	12.9	12.9	29.9	28.7	21.5	12.1
			26.06										
International E&Ps													
CNOOC Ltd	HKD	HK	3.49	12.2	7.0	5.3	5.7	5.8	6.9	20.7	nm	13.9	10.6
Tullow Oil PLC	GBP	GB	1.62	38.4	18.6	4.2	3.8	28.6	nm	nm	55.1	25.4	14.4
Soco International PLC	GBP	GB	0.76	9.9	13.6	8.8	2.4	2.6	4.0	nm	nm	65.0	15.7
			5.87										
Midstream													
Enbridge Inc	USD	CA	3.60	60.2	51.9	46.8	43.1	39.7	36.4	32.9	30.5	28.7	25.9
			3.60										
Drilling													
Unit Corp	USD	US	1.90	9.2	7.9	5.9	5.8	6.5	5.7	nm	nm	18.9	9.5
			1.90										
Equipment & Services													
Halliburton Co	USD	US	3.60	37.6	24.5	14.7	16.5	15.9	12.5	33.3	nm	49.6	17.6
Helix Energy Solutions Group Inc	USD	US	1.86	13.4	14.7	5.2	4.2	7.2	4.0	46.0	nm	nm	34.8
Schlumberger Ltd	USD	US	3.56	28.7	28.3	21.6	18.7	16.4	14.1	23.3	67.6	44.6	23.1
			9.02										
Solar													
JA Solar Holdings Co Ltd	USD	US	0.71	nm	1.0	nm	nm	nm	7.7	3.9	9.1	33.2	8.7
Sunpower Corp	USD	US	0.31	5.3	4.2	74.4	40.7	4.3	4.6	3.1	nm	nm	20.4
			1.02										
Oil & Gas Refining & Marketing													
Valero Energy Corp	USD	US	3.53	nm	41.8	16.7	13.6	16.2	10.9	7.5	18.0	13.3	10.7
			3.53										
Research Portfolio													
Cluff Natural Resources PLC	GBP	GB	0.23	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm
EnQuest PLC	GBP	GB	0.62	nm	6.0	6.8	2.1	2.3	4.2	40.3	2.7	30.8	2.6
JKX Oil & Gas PLC	GBP	GB	0.10	0.5	0.6	0.7	1.0	1.8	5.1	nm	nm	nm	nm
Ophir Energy PLC	GBP	GB	0.04	nm	nm	nm	nm	nm	3.3	nm	nm	nm	nm
Shandong Molong Petroleum Machiner	HKD	HK	0.07	11.2	4.4	6.0	nm	nm	nm	nm	nm	nm	nm
Sino Gas & Energy Holdings Ltd	AUD	AU	0.12	nm	nm	nm	97.0	nm	97.0	nm	nm	32.3	6.9
WesternZagros Resources Ltd	CAD	CA	0.02	nm	nm	nm	nm	nm	nm	nm	nm	nm	21.6
			1.20										
		Cash	1.37										
		Total	100										
		PER		13.8	9.1	7.7	8.0	8.9	9.7	20.4	34.0	20.3	14.3
		Med. PER		13.3	9.2	7.8	8.7	9.1	9.8	25.1	30.5	22.8	15.1
		Ex-gas PER		14.2	9.3	7.8	7.7	8.7	9.6	18.7	30.8	19.4	13.7

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 13 years, together with IEA forecasts for 2017.

	2000	2001	2002	2003	2004	2005	2006	2007	2008	*2009*	2010	2011	2012	2013	2014	2015	2016	2017E
																	IEA	*IEA*
World Demand	**76.7**	**77.4**	**77.7**	**79.3**	**82.5**	**84.0**	**85.2**	**87.0**	**86.5**	**85.5**	**88.5**	**89.5**	**90.7**	***91.7***	***93.0***	***95.0***	***96.6***	***97.9***
Non-OPEC supply (includes Angola, Ecuador and Indonesia for periods when each country was outside OPEC[1])	**46.2**	**47.2**	**48.1**	**49.1**	**50.3**	**50.4**	**51.3**	**50.5**	**49.6**	**51.4**	**52.7**	**52.8**	**53.3**	***54.5***	***57.0***	***58.5***	***56.9***	***57.3***
Angola supply adjustment[1]	-0.8	-0.7	-0.9	-0.9	-1.0	-1.2	-1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ecuador supply adjustment[1]	-0.4	-0.4	-0.4	-0.4	-0.5	-0.5	-0.5	-0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Indonesia/Gabon supply adjustment[2]	1.2	1.2	1.1	1.0	1.0	0.9	0.9	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.8
Non-OPEC supply (ex. Angola/Ecuador and inc. Indonesia for all periods)	**46.2**	**47.3**	**47.9**	**48.8**	**49.8**	**49.6**	**50.3**	**51.0**	**50.6**	**51.4**	**52.7**	**52.8**	**53.3**	**54.5**	**57.0**	**58.5**	**57.7**	**58.1**
OPEC NGLs	3.1	3.4	3.7	3.9	4.2	4.3	4.3	4.3	4.5	5.1	5.5	5.9	6.4	*6.1*	*6.3*	*6.5*	*6.7*	*6.8*
Non-OPEC supply plus OPEC NGLs (ex. Angola/Ecuador and inc. Indonesia for all periods)	**49.3**	**50.7**	**51.6**	**52.7**	**54.0**	**53.9**	**54.6**	**55.3**	**55.1**	**56.5**	**58.2**	**58.7**	**59.7**	**60.6**	**63.3**	**65.0**	**64.4**	**64.9**
Call on OPEC-12[3]	27.4	26.7	26.1	26.6	28.5	30.1	30.6	31.7	31.4	29.0	30.3	30.8	31.0	31.1	29.7	30.0	32.2	33.0
Iraq supply adjustment[4]	-2.6	-2.4	-2.0	-1.3	-2.0	-1.8	-1.9	-2.1	-2.4	-2.4	-2.4	-2.7	-3.0	-3.1	-3.3	-4.0	-4.4	-4.2
Call on OPEC-11[5]	**24.8**	**24.3**	**24.1**	**25.3**	**26.5**	**28.3**	**28.7**	**29.6**	**29.0**	**26.6**	**27.9**	**28.1**	**28.1**	**28.0**	**26.4**	**26.0**	**27.8**	**28.8**

[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: April 2017 Oil market Report

Global oil demand in 2016 was nearly 10m b/day up on the pre-recession (2007) peak. This means the combined effect of the 2007/08 oil price spike and the 2008/09 recession was small and was shrugged off remarkably quickly. The IEA forecast a rise of 1.4m b/day in 2017, which would take oil demand to an all-time high of 98.0m 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:

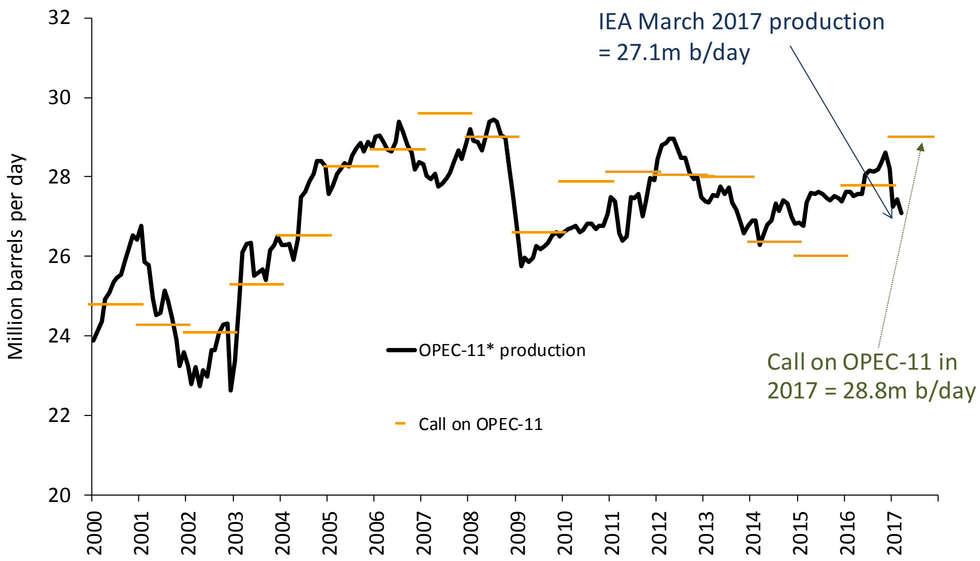
('000 b/day)	31-Dec-10	30-Nov-14	31-Mar-17	Change vs Dec 2010	Change vs Nov 2014
Saudi	8,250	9,650	**9,940**	**1,690**	**290**
Iran	3,700	2,780	**3,785**	85	**1,005**
Iraq	2,385	3,370	**4,430**	2,045	**1,060**
UAE	2,310	2,800	**2,915**	605	**115**
Kuwait	2,300	2,790	**2,705**	405	**-85**
Nigeria	2,220	1,970	**1,550**	-670	**-420**
Venezuela	2,190	2,350	**2,000**	-190	**-350**
Angola	1,700	1,640	**1,630**	-70	**-10**
Libya	1,585	580	**620**	-965	**40**
Algeria	1,260	1,100	**1,040**	-220	**-60**
Qatar	820	650	**610**	-210	**-40**
Ecuador	465	561	**530**	65	**-31**
OPEC-12	**29,185**	30,241	**31,755**	**2,570**	**1,514**

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+ 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 – 2016



Source: IEA Oil Market Report (April 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 'referenced' OPEC production, for October 2016, and used as a starting point for the cuts, was around 33.7m b/day, so 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 - well in excess of most expectations in the lead up to the meeting.

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 will be kept in place initially for six months, extendable for another six months depending on how the oil market evolves.

Clearly, OPEC economies are under significant stress, which is the near-term driver for the decision to cut. 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, well 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 have the ability to 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. Based on current forecasts of higher oil prices, the IEA forecasts that non-OPEC supply recovers by 0.4m b/day in 2017, as US onshore production swings from decline back to growth.

Looking further ahead to how global oil supply may evolve in the current oil price environment, we must consider in particular increases in supply from two regions: North America and Libya.

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 since, but now is returning 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 $50-60 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 3m 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 $50-60 world are far lower than in a $100 world, but with efficiency improvements, enough to see moderate growth returning.

With the recovery in Iranian production in 2016, the one country globally that still has the potential for a meaningful rebound is Libya. At its peak, Libya was producing around 1.6m b/day, but civil war since 2012 has reduced production to around 0.3-0.5m b/day for most of the last four years. If the country is able to re-open its key export facilities (Es Sider, Zawiya, Ras Lanuf and Zuetina), we believe it possible for production to recover by around 0.5m b/day to 0.8-1.0m b/day, however any further gains are likely to be muted given the extent of above-ground damage to oil infrastructure that has occurred. The National Minister indicated in January 2017 that he hoped Libyan oil production would reach 'pre-war levels' around 2021.

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 reported that oil demand grew in 2016 by around 1.6m b/day, and expect 2017 growth of 1.3m 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 growth forecast for 2017 comprises an increase in non-OECD demand of 1.5m b/day and a small decline OECD demand. The components of this non-OECD demand growth can be summarised as follows:

Figure 8: Non-OECD oil demand

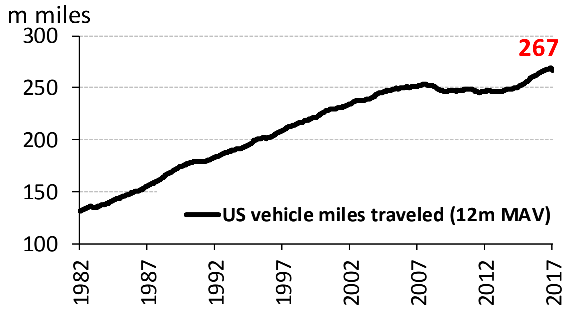
Non-OECD demand (source: IEA monthly report)

m b/day	Demand								Growth						
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016e**	**2017e**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016e**	**2017e**
Asia	19.7	20.3	21.4	22.1	22.8	24.0	25.0	26.0	0.6	1.1	0.7	0.7	1.2	1.0	1.0
Middle East	7.3	7.4	7.8	7.9	8.4	8.4	8.3	8.6	0.1	0.4	0.1	0.5	0.0	-0.1	0.2
Latin America	6	6.2	6.4	6.7	6.8	6.8	6.6	6.7	0.2	0.2	0.3	0.1	0.0	-0.1	0.0
FSU	4.1	4.4	4.6	4.7	4.66	4.6	4.8	4.9	0.3	0.2	0.1	0.0	0.0	0.2	0.1
Africa	3.5	3.5	3.8	3.9	3.8	4.1	4.2	4.3	0.0	0.3	0.1	-0.1	0.3	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	**41.3**	**42.5**	**44.7**	**46.0**	**47.2**	**48.6**	**49.62**	**51.1**	**1.2**	**2.2**	**1.3**	**1.16**	**1.39**	**1.1**	**1.5**

Source: IEA Oil Market Report (April 2017)

Asia has settled down into a steady pattern of growth since 2010, and accounts for the majority 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 2016 is forecast to be flat. 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 2-3% 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	53
Brent	30	32	35	46	64	75	82	103	67	84	115	112	108	99	52	45	55
Brent/WTI (12m MAV)	**30**	**33**	**37**	**48**	**65**	**75**	**82**	**104**	**68**	**84**	**107**	**103**	**103**	**96**	**51**	**45**	**54**
Brent/WTI y-on-y change (%)		8%	12%	30%	37%	15%	9%	26%	-35%	24%	27%	-4%	0%	-7%	-47%	-11%	20%
Brent/WTI (5yr MAV)	30	25	32	37	42	51	61	75	79	82	89	93	93	99	92	80	70

We expect oil to trade in a $50-60 range in the near term, supported at the lower end by OPEC. If this price range persists, we expect North American unconventional supply declines to flatten and subsequently deliver 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 during 2018.

Natural gas market

US supply & demand: recent past

On the demand side, industrial gas demand and electricity gas demand, each about a third of total US gas demand, are key. Commercial and residential demand, which make up the final third, 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 2016 to around 21.8 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 2015, 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.

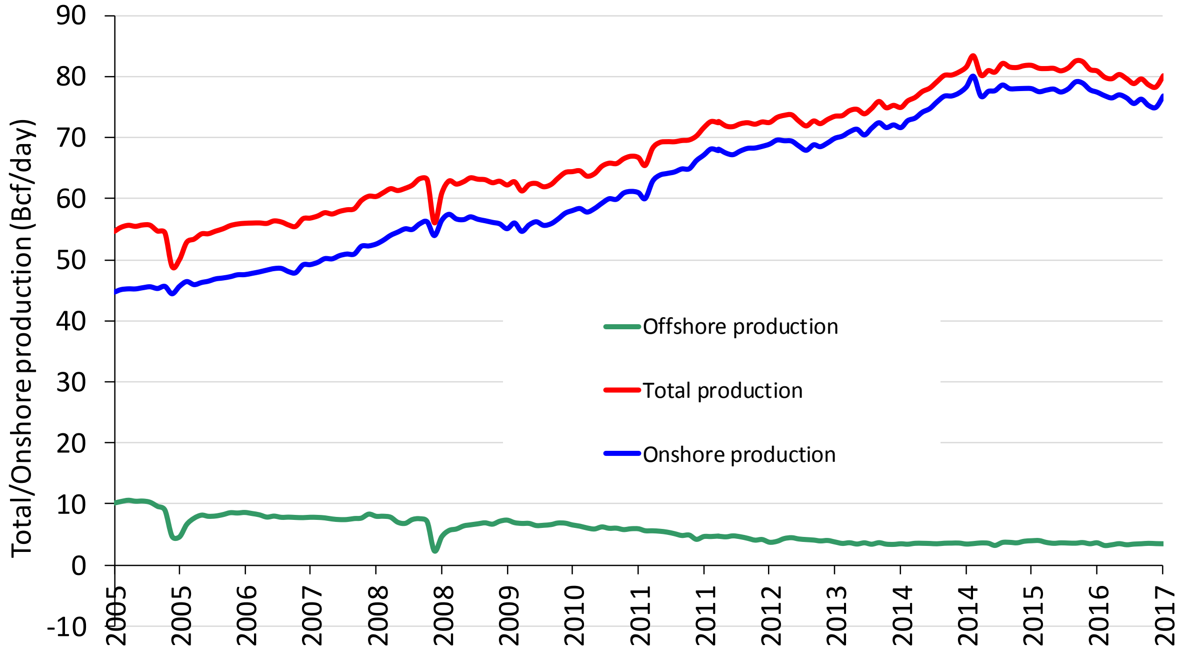
Total gas demand in 2016 (including Canadian and Mexican exports) was around 81.9 Bcf/day, up by 1.9 Bcf/day (2.4%) vs 2015 and up 4.2 Bcf/day (5%) vs the 3 year average. The biggest change in 2016 vs 2015 is exports to Mexico (+1.1 Bcf/day), as the network of gas pipelines from Texas into Mexico expands. Industrial demand (+0.5 Bcf/day) was made a positive contribution, as US GDP picked up.

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 5 main moving parts: onshore and offshore domestic production, net imports of gas from Canada, exports of gas to Mexico and imports of liquefied natural gas (LNG). Of these, onshore supply is the biggest component, making up over 85% of total supply.

Since the middle of 2008 the weaker gas price in the US reflects growing onshore US production driven by rising gas shale 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 171 at the end of April 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) is now at 76.8 Bcf/day, 19.4 Bcf/day (34%) above the 57.4 Bcf/d peak in 2009 before the rig count collapsed.

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



Source: EIA 914 data (February 2017 published in May 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.

The outlook for US oil production growth changed significantly over the last 12 months with the decline in the oil price. US onshore oil production peaked in March 2015 and is now declining, which has caused associated gas production to decline, though only a little (there has been a shift to gassier shale oil basins such as the Permian). And as US oil supply starts to grow again in 2017, so associated gas production will also pick 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 recent months. Then there is an expected decline in legacy gas fields, particularly if the gas drilling rig count stays low. Considering these factors together, we expect US onshore gas production to return to growth in 2017 (around 2 bcf/day) if the price remains in the $2.50-$3.50mcf range.

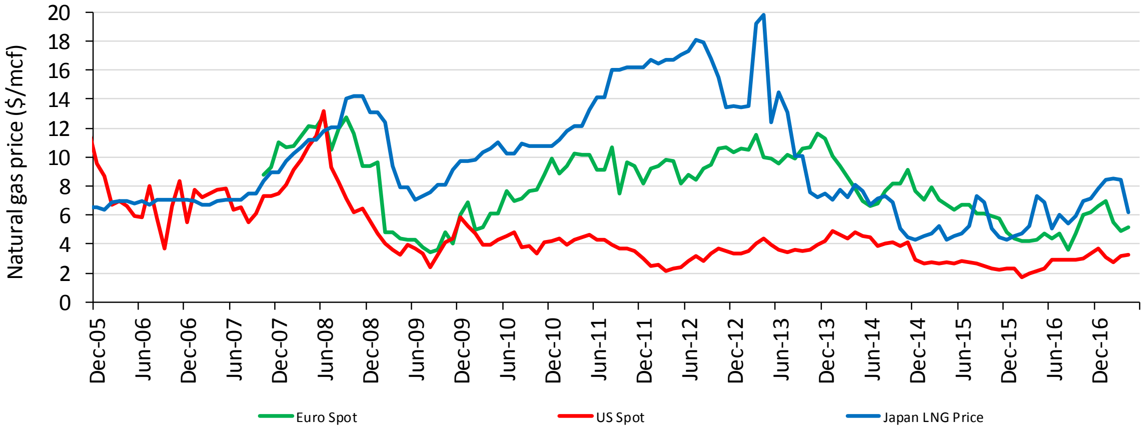
	2009	2010	2011	2012	2013	2014	2015	2016	2017E
Onshore production - average (Bcf/day)	55.9	58.6	64.6	68.4	70.2	75.3	77.8	77.1	79.0
Change (Bcf/day)	0.9	2.7	5.9	3.9	1.8	5.1	2.5	-0.7	1.9
Change (%)	*1.7%*	*4.8%*	*10.1%*	*6.0%*	*2.6%*	*7.2%*	*3.3%*	*-0.8%*	*2.5%*

Source: EIA; Guinness estimates

Liquid natural gas (LNG) arbitrage

The UK national balancing point (NBP) gas price – which serves as a proxy to the European traded gas price – strengthened in 2016, rising to around $7/mcf at the end of 2016, predominantly as a result of price-linkage to recovering oil prices. We note that current prices remain at a premium to the US gas price (c.$5 versus c.$3).

Asian spot LNG prices fell sharply down to around $4.50/mcf at the start of 2016 (pulled lower by lower oil prices and due to a negative demand response in Asian markets to previously higher natural gas prices) but have since recovered to around $6/mcf.



Demand outlook

US total demand in 2016 (including exports to Canada and Mexico) was around 81 Bcf/day, nearly 3 Bcf/day higher than 2014. We expect demand in 2017, assuming prices remain around $$3/mcf, to be about flat, with weaker power generation demand (coal to gas switching returning at our assumed price level) offset by stronger residential/commercial use (normalised weather) and a rise in exports to Mexico.

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 and Canada, many of which are still in the construction stages but will come online by 2020. Exports from the first project to come on-line, Sabine Pass, commenced in February 2016. Additional exports are slated to come from the following projects, but exports will ultimately depend on spot economics between Henry Hub and global prices:

Project	Location	2017E	2018E	2019E	2020E
Sabine Pass 3	LA	0.6			
Sabine Pass 4	LA	0.6			
Sabine Pass 5	LA			0.7	
Freeport 1	TX		0.5		
Freeport 2	TX			0.5	
Freeport 3	TX			0.5	
Cove Point LNG	MD		0.8		
Cameron 1	LA		0.6		
Cameron 2	LA		0.6		
Cameron 3	LA			0.6	
Corpus Christi 1	TX			0.8	
Corpus Christi 2	TX			0.8	
Sub-total		**1.2**	**2.5**	**3.9**	**0.0**
Total (cumulative)		**1.2**	**3.7**	**7.6**	**7.6**

Source: 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 large new Gulf Coast facilities planned for 2017, the first new crackers 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 0.8-1.5 Bcf/day per year, although this will be affected by actual gas prices.

Increased demand from natural gas vehicles (compressed natural gas typically for shorter haul and liquefied natural gas for longer haul journeys) is emerging, but starts from such a small base that it is unlikely to contribute meaningfully to the overall demand picture in the next 5 years.

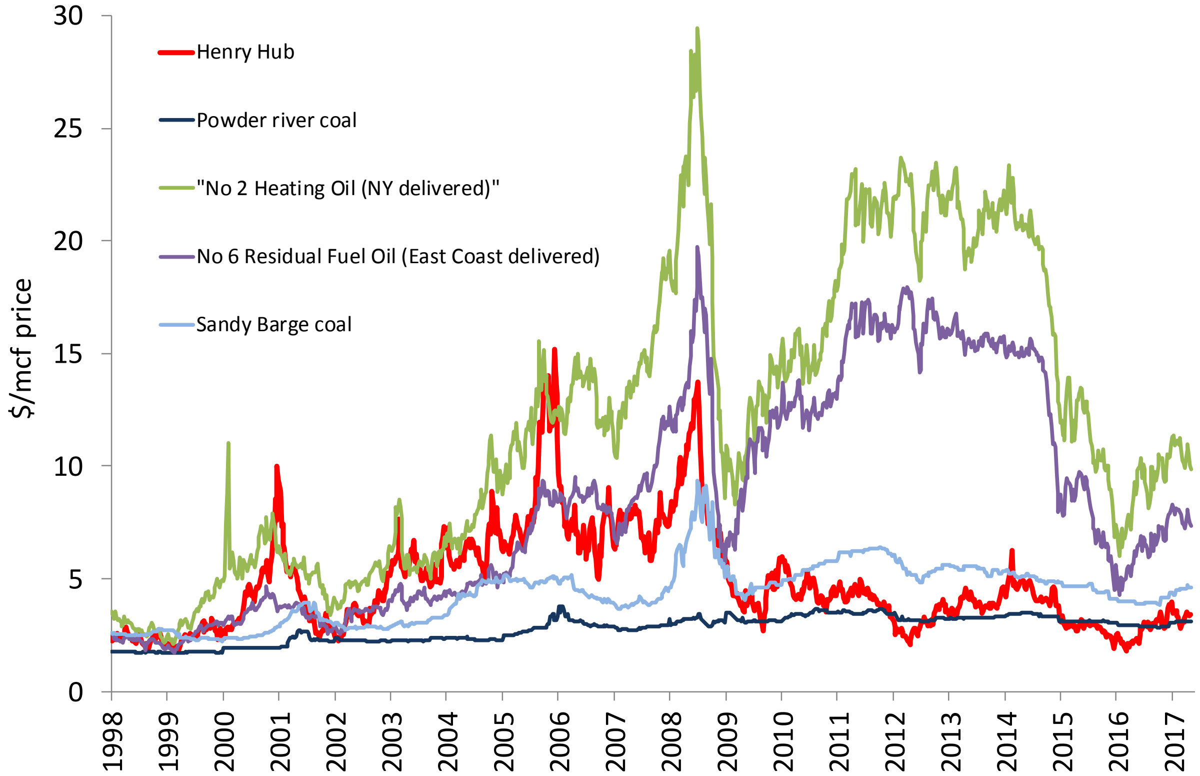
Other

The oil/gas price ratio ($ per bbl WTI/$ per mcf Henry Hub) of around 14x at the end of April continues well outside the long-term ratio of 6-9x. Recent weakness in both oil and natural gas prices has continued to keep the ratio elevated but, at $70 oil, this would imply the gas price at around $8 if the long-term ratio returned.

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. With the gas price trading below the coal price support level for the first 8 months of 2012, resulting coal to gas switching for power generation was significant. We have seen a similar switch in demand trends in the 2015/early 2016 period although note that recent increases in gas price towards $3/mcf will start to moderate the level of switching.

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

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



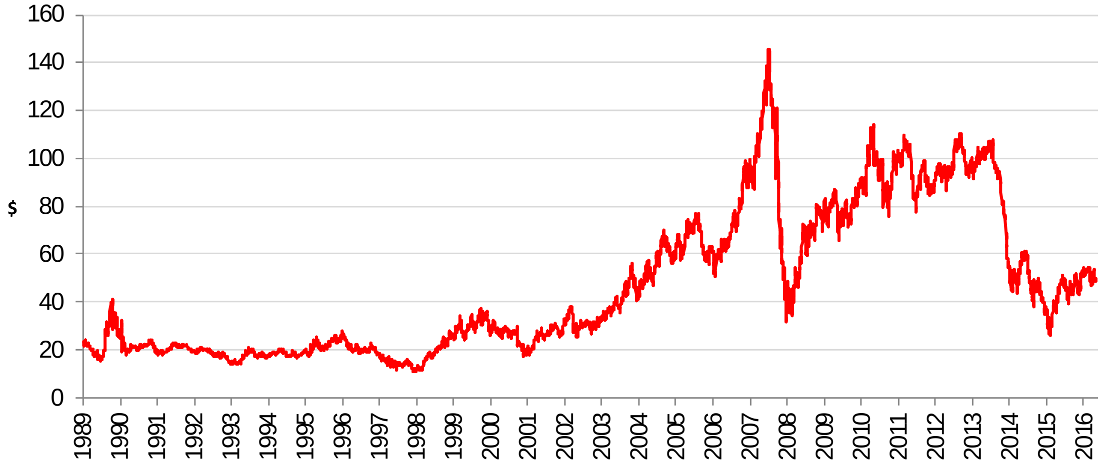
Source: Bloomberg LP (May 2017)

Conclusions about natural gas

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.

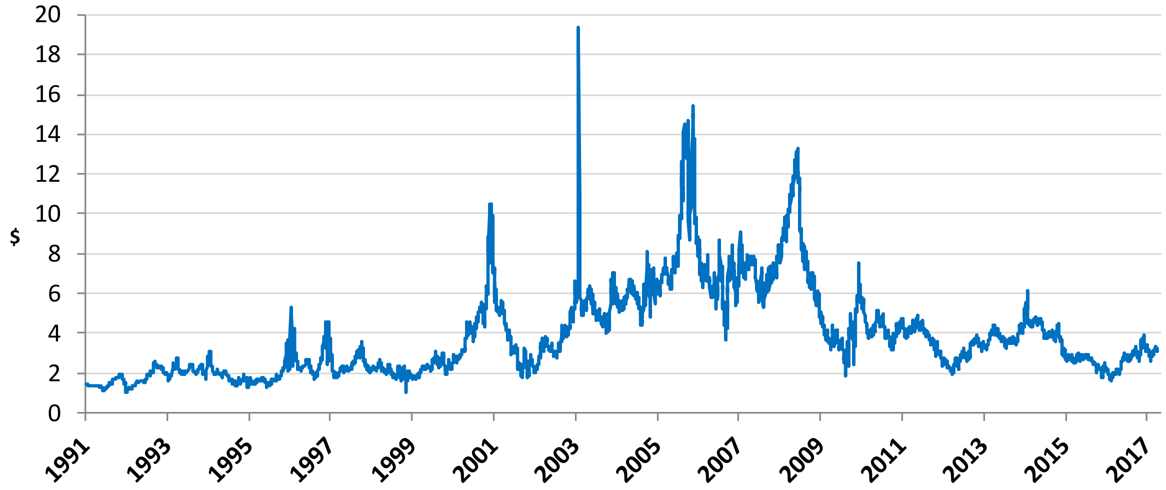
After 2005 we saw a further strong run-up in the oil price. Hurricanes Katrina and Rita, which devastated New Orleans, caused oil to spike up to $70 in August 2005, and it spiked up again in July 2006 to $78 after a three week conflict between Israel and Lebanon threatened supply from the Middle East. 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 strengthened sharply in 2016 as a result of OPEC cutting production again, supported by lower production levels from the US onshore.

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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