THE GUINNESS GLOBAL ENERGY REPORT

Developments and trends for investors in the global energy sector | November 2019

GUINNESS GLOBAL ENERGY FUND

Fund size: $204m (31.10.2019)

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 flat; demand concerns weigh on prices

Brent and WTI broadly flat over the month at $60/$54. Saudi has recovered rapidly from the September 14th attacks and now pushing ahead with the Aramco IPO as a local listing. Global oil demand expectations for 2019 edging down – IEA lowered their forecast to growth of 1.0m b/day (from 1.1m b/day). US oil directed drilling rig count down to 691, 22% lower than last year's peak.

NATURAL GAS

US, European and Asian gas prices slightly higher

Henry Hub prices strengthened in the last few days of October to close at $2.63/mcf – short term spike driven by colder weather. Market still looks oversupplied by around 2 Bcf/day on a weather adjusted basis. Asian and European gas prices are broadly unchanged (at c.$5/mcf and c.$4/mcf), with the market well supplied.

EQUITIES

Energy underperforms the broad market in October

The MSCI World Energy Index (net return) declined by 1.6% in October, underperforming the MSCI World Index (net return) which rose by 2.5% over the month (all in US dollar terms).

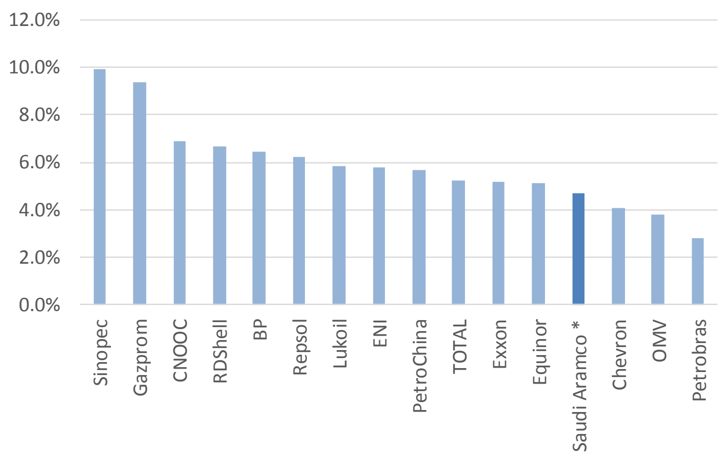
CHART OF THE MONTH

Saudi Aramco IPO launched

The IPO of Saudi Aramco launched at the start of November. In our Managers Comments we review some of the key things that we have learnt in reviewing the IPO documentation. Numerous press reports indicate a wide valuation range of around $1.2trn to $2.3trn with a mid point of around $1.6trn. Based on a $1.6trn valuation, we present below the dividend yield for 2020 (based on $60/bl Brent) for Saudi Aramco and a range of its global peer integrated oil companies

Dividend Yield 2020 at $60/bl Brent for global integrated oils

** Assumes Saudi Aramco valuation at $1.6trn*



Source: Bloomberg, Guinness Asset Management estimates

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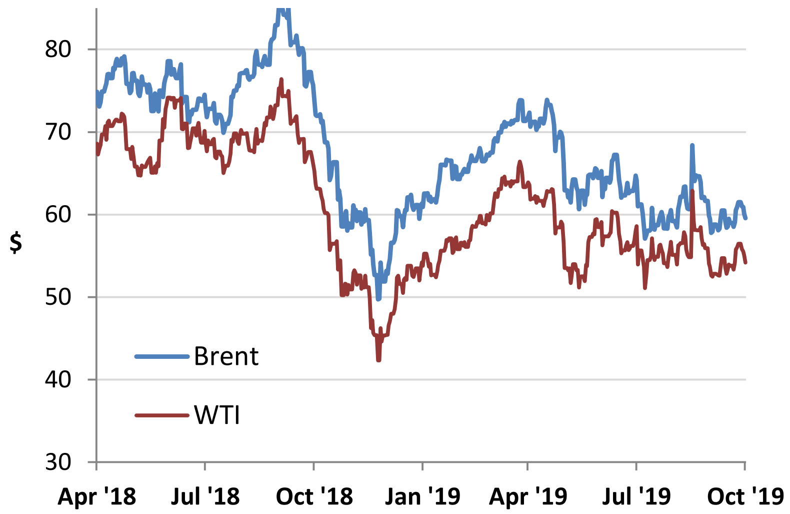
1. OCTOBER IN REVIEW

i) Oil market

Figure 1: Oil price (WTI and Brent $/barrel) 18 months April 30 2018 to October 31 2019



Source: Bloomberg LP

The West Texas Intermediate (WTI) oil price started October at $54.1/bl, and traded in a tight range between around $53 and $56/bl, throughout the month, before closing at $54.2/bl. WTI has averaged $57/bl so far in 2019, having averaged $65/bl in 2018, $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 $59.9/bl, trading between $57 and $61/bl, before closing at $59.6/bl. Brent has averaged $64/bl so far in 2019, versus $72/bl in 2018. The gap between the WTI and Brent benchmark oil prices narrowed slightly over the month, ending October at around $5.4/bl, versus over $9/bl at the end of May.

Factors which strengthened WTI and Brent oil prices in October:

- **Attacks on Saudi oil production and processing facilities causing lower OPEC production**
  Following the attacks on Saudi Arabia's Khurais oilfield and its Abqaiq oil processing facility, September saw Saudi production down by an average of 1.6m b/day versus the month before. This disruption had some impact on global flows of oil in October. That said, Saudi appears to have recovered rapidly from the attacks, with October production averaging 9.9m b/day, so back to August levels. With the upcoming IPO of Saudi Aramco, it is likely that some of this recovery in production comes from 'other sources' to Abqaiq, but even so it seems far to conclude that the attacks have had limited lasting impact.

- **Slowing US onshore drilling and fracturing activity**
  The US oil directed rig count continued to fall (from 713 rigs to 691 rigs over the month and now down 197 rigs (22%) from the peak of 888 rigs in November 2018. While the US onshore continues to grow, full year growth expectations are being moderated and it is now likely, in our opinion, that the US disappoints on production growth relative to expectations at the beginning of the year.

Factors which weakened WTI and Brent oil prices in October:

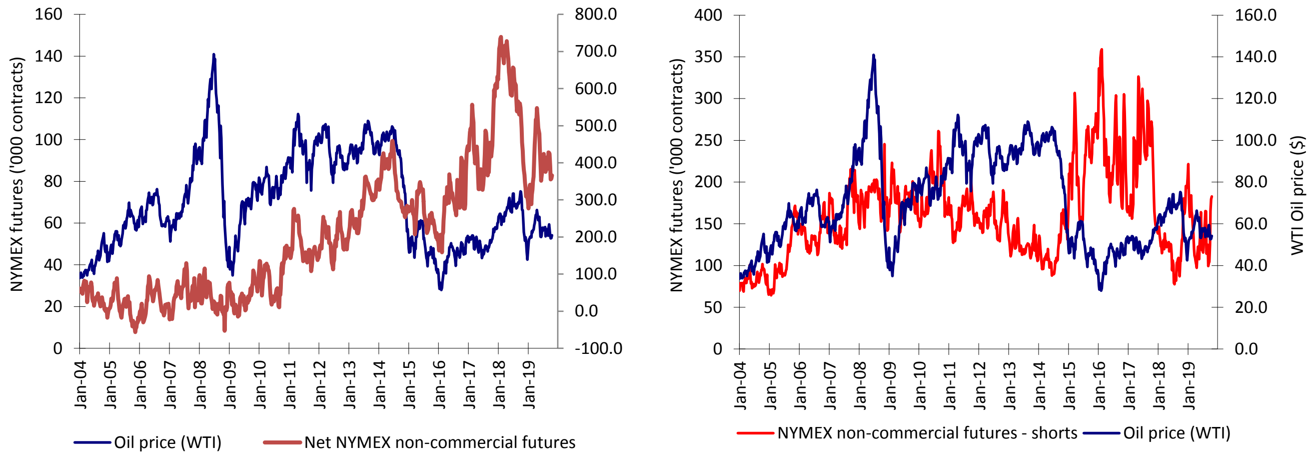
- **Global oil demand expectations remaining under pressure**
  The IEA released its October Oil Market Report, and lowered 2019 oil demand growth expectations to 1.0m b/day (from 1.1m b/day). This coincided with the IMF lowering their global GDP forecast for 2019 to 3.0%, its lowest level since 2008-09 and a 0.3% downgrade from the outlook presented in April 2019. Oil demand growth in 2020 is expected to be 1.2m b/day, corresponding to the IMF's GDP forecast for next year of 3.4%.

- **US onshore supply growth rebounding in August (latest data)**
  The latest EIA production data showed a 191,000 b/day onshore oil production increase in August 2019 (latest data point), taking year-on-year growth down to 1.0m b/day. Onshore rig operators in the US have signalled that they expect a further decline in the rig count over the next few months, increasing expectations that US shale oil production growth will start to falter. There is typically a 5-6 month lag from rig count change to production change.

Speculative and investment flows

The New York Mercantile Exchange (NYMEX) net non-commercial crude oil futures open position was 366,000 contracts long at the end of October versus 424,000 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 rose to 183,000 contracts at the end of October versus 104,000 at the end of September.

Figure 2: NYMEX Non-commercial net and short futures contracts: WTI January 2004 – October 2019

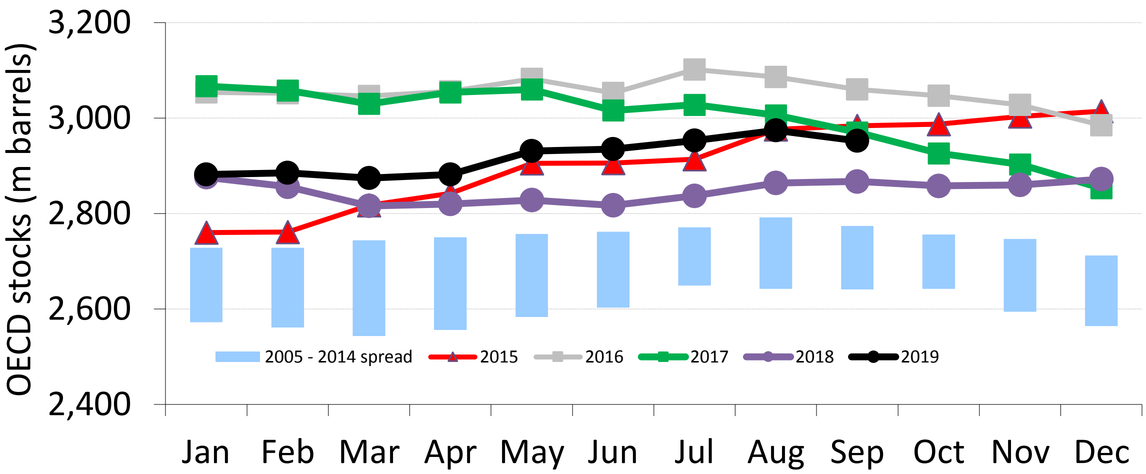


Source: Bloomberg LP/NYMEX/ICE (2019)

OECD stocks

OECD total product and crude inventories at the end of September (latest data point) were estimated by the IEA to be 2,952m barrels, down by 22m barrels versus the level reported for August. This compares to a 10-year average decrease for September of 10m barrels, implying that the market was undersupplied in September by around 0.4m b/day. Inventories have built since the start of the year by around 80m barrels.

Figure 3: OECD total product and crude inventories, monthly, 2004 to 2019



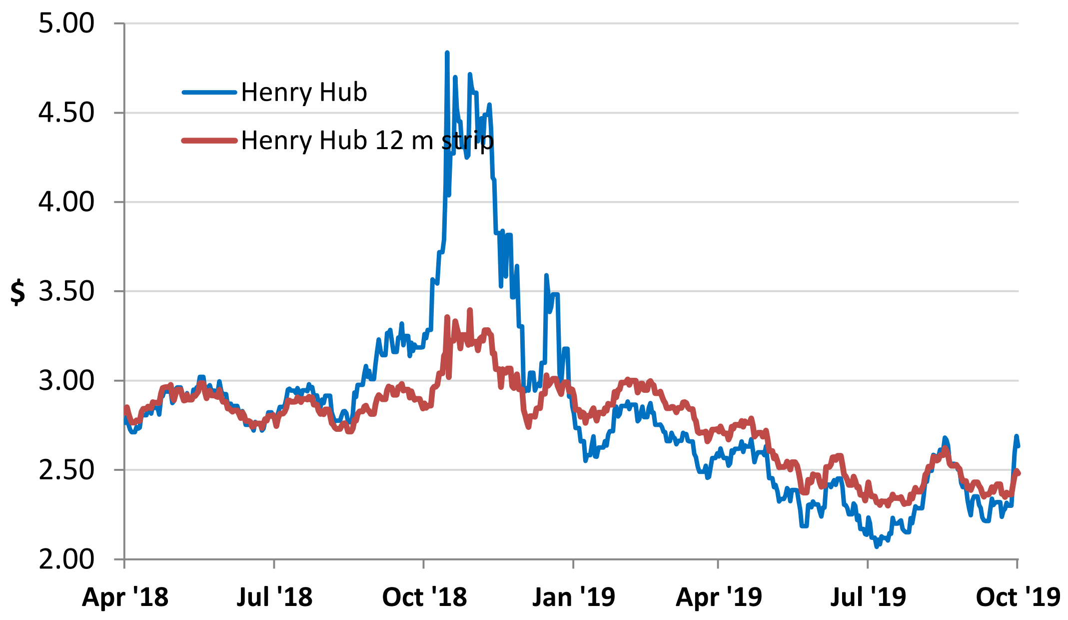
Source: IEA Oil Market Reports (October 2019 and older)

ii) Natural gas market

The US natural gas price (Henry Hub front month) opened October at $2.33/mcf (1,000 cubic feet), dipped to $2.21/mcf in the middle of the month, before rallying hard to close at $2.63/mcf. The spot gas price has averaged $2.54/mcf so far in 2019, which compares to an average gas price of $3.07 in 2018, $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) rose slightly over the month, opening at $2.40/mcf and closing at $2.48 /mcf. The strip price averaged $2.90 in 2018, $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 2019 to October 31 2019



Source: Bloomberg LP

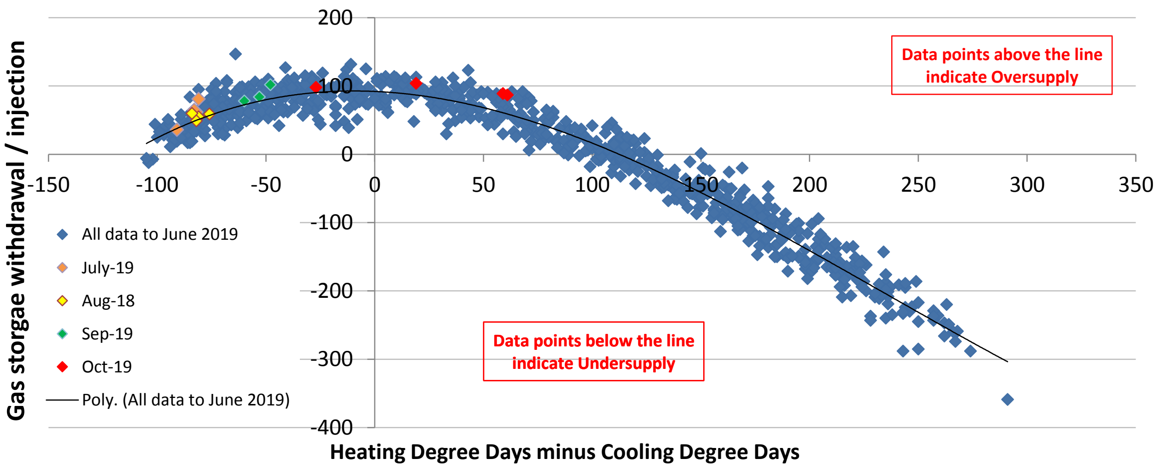
Factors which weakened the US gas price in October included:

- **Structurally oversupplied market**
  Adjusting for the impact of weather in October, the most recent movements of gas in storage suggest the market is, on average, operating at a surplus of around 2 Bcf/day (as indicated by the red dots on the graph below).

- **Increase in US onshore natural gas production**
  Onshore US natural gas production averaged 101.4 Bcf/day in August 2019 (the latest available data point), up by 1.9 Bcf/day versus the level reported for July. Onshore gas production is now 10.2 Bcf/day up on the level reported twelve months earlier. 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 while a slowdown in US natural gas demand growth will also put further pressure on the supply/demand balance.

  It is worth noting that this level of production growth is being achieved despite the natural gas oriented drilling rig count falling to 130, down 67 rigs (33%) from the same period in 2018. In addition, the level of US LNG exports continues to grow, now at 4.5 Bcf/day in October 2019, over 50% higher than the level achieved in October 2018.

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



Source: Bloomberg LP; Guinness Asset Management

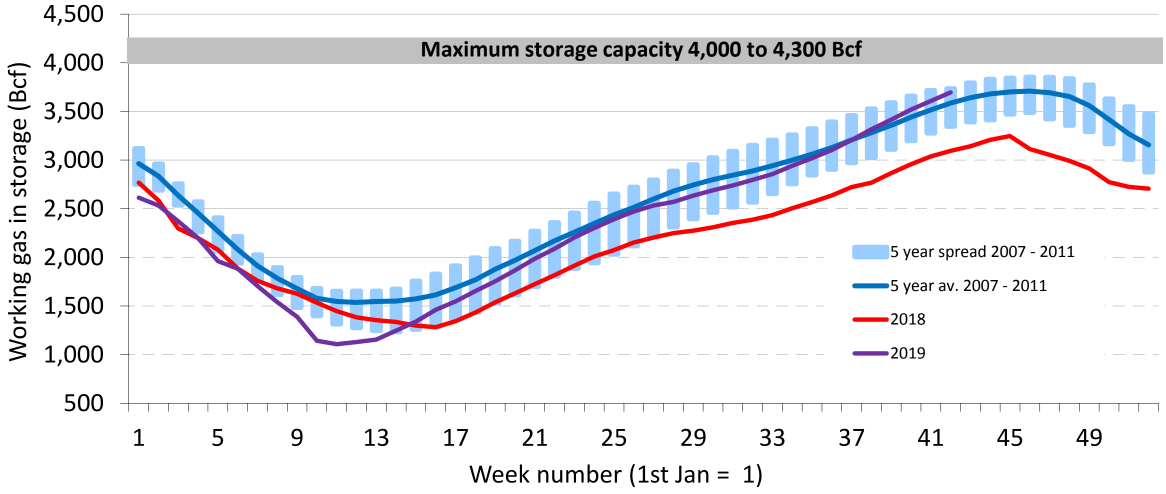
Factors which strengthened the US gas price in October included:

- **Coal to gas switching**
  With gas prices below $2.50/mcf over the summer, we believe there has been significant gas to coal switching by US power utilities. Rystad Energy forecasts that natural gas-fueled generation will hit a record 38% share of total US electrical power generated in 2019. This is almost two and a half times the level seen in 2008.

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 3.7 Tcf. Current gas in storage is in line with the 10 year average as a result of strong demand plus increasing volumes of gas exported via LNG offsetting strong onshore production growth. The high visibility of low cost supply growth for 2019 is keeping a cap on prices despite the fact that inventories have spent much of the year below the 10 year average level.

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



Source: Bloomberg; EIA (November 2019)

2. MANAGER'S COMMENTS

Ten things that we learnt from researching the Saudi Aramco IPO

After several years of waiting, the IPO of Saudi Aramco has recently been launched. We have reviewed some of the IPO documentation and pre-IPO research and comment here on we learnt from the process.

The size and scale of Saudi Aramco

The IPO documentation has confirmed that Saudi Aramco is a 'one of a kind' company.

- It is comfortably the **largest oil company in the world** and one of the largest corporates globally. It has 227 billion barrels of oil/NGL reserves, equivalent to over 20% of global oil reserves (according to the BP Statistical Review of World Energy) and equal to 5x the proved oil/NGL reserves of the 'super-majors' combined (Exxon; Chevron; Royal Dutch Shell; Total; BP). With oil production of around 9.9m b/day and NGL production of around 1.2m b/day, its proved reserves will last for over 50 years (versus around 12 years for the super-majors). The operating cost of producing a barrel of oil is less than $3/bl, putting the company at the bottom of the industry's cost curve. Indeed, Saudi Aramco is amongst the biggest or lowest cost oil and natural gas producers on nearly all operating metrics.

- Saudi Aramco has **particularly high exposure to the upstream (exploration and production) business**, with 98% of 2018 EBIT coming from the production of oil and gas and only 2% coming from downstream operations. We note that the company is in the process of acquiring a 70% stake in SABIC (a Saudi Petrochemicals company) and that future growth capex is focussed towards downstream oil, chemicals and the production of natural gas and that these investments will reduce the relative exposure to upstream operations. Nonetheless, Saudi Aramco is substantially more upstream-oriented than the super-majors.

Financial and operating metrics

The IPO materials have provided us with financial and operating data for 2017 and 2018 and has allowed us to make our own 'first stab' estimates for 2019 and 2020.

- With low capital and operating costs, we see that Saudi Aramco is a **highly free cash flow generative** company. Based on an oil price of $60/bl, we see Saudi Aramco generating a free cash flow return versus capital employed in 2020 of around 22%. This is noticeably higher than the super-majors (who average around 8%), and reflects the lower cost of production and lower capital intensity.

- Saudi Aramco has a **pristine balance sheet** and will essentially have zero net debt over 2019 and 2020 if Brent oil prices average around $60/bl Brent. This is cleaner than the peer group of global integrated oil companies, though most peers are also running reasonably conservative balance sheets.

- Despite producing around 11m b/day of oil/NGLs, the capital employed in Saudi Aramco is very low (at $300bn on our calculations) and thus the company is currently delivering a **very high return on capital employed** relative to its peer group. We note Saudi Aramco has $61m of capital employed per produced barrel versus the super-majors at around $165m. On our assumption of $60/bl Brent oil, we seeing ROCE falling back towards 25-30% over the next five years but it still being much higher than the Super Majors (at around 7%).

- Saudi Aramco is subject to a **royalty regime that limits profitability at higher oil prices**. From next year, the company will pay a production royalty of 15% for Brent oil prices up to $70 per barrel, a royalty of 45% for prices between $70/bl and $100/bl and then 80% royalty for prices in excess of $100/bl. These royalties are paid in addition to a flat income tax rate of 50%. The combined effect is that the oil price sensitivity of the company likely ends up similar to that of the super-majors as the greater upstream exposure is offset by the progressive taxation regime.

Summary financial and operating metrics comparison

Source: Guinness Asset Management estimates, Bloomberg

	Upstream volume growth		ROCE		Net Debt/Net Debt+Equity		Net debt/EBITDA	
	2019	2020	2019	2020	2019	2020	2019	2020
BP	4.9%	5.3%	6.3%	6.9%	0.3x	0.3x	1.3x	1.0x
Chevron	5.5%	4.3%	6.4%	7.3%	0.1x	0.0x	0.4x	0.1x
ENI	2.3%	3.9%	4.7%	5.9%	0.2x	0.2x	0.9x	0.7x
Equinor	2.3%	5.0%	8.5%	10.1%	0.3x	0.2x	0.6x	0.4x
Exxon	2.2%	4.3%	8.0%	8.1%	0.1x	0.1x	0.8x	0.7x
OMV	14.8%	5.4%	7.8%	9.6%	0.3x	0.2x	0.9x	0.5x
RDShell	1.8%	1.3%	6.7%	7.0%	0.2x	0.2x	1.1x	1.1x
Repsol	0.3%	1.0%	4.8%	6.1%	0.2x	0.2x	1.5x	1.1x
TOTAL	5.8%	4.1%	7.5%	9.0%	0.1x	0.1x	0.6x	0.3x
CNOOC	3.0%	2.8%	8.3%	8.1%	0.1x	0.1x	0.6x	0.5x
Gazprom	1.8%	1.8%	7.7%	6.9%	0.2x	0.2x	1.4x	1.6x
Lukoil	-3.0%	1.6%	15.3%	12.2%	-0.1x	-0.1x	-0.3x	-0.6x
Petrobras	6.2%	6.0%	7.1%	8.4%	0.4x	0.4x	2.2x	1.6x
PetroChina	3.1%	2.8%	3.9%	4.2%	0.3x	0.3x	1.5x	1.4x
Sinopec	1.2%	1.3%	4.5%	6.2%	0.0x	0.0x	0.1x	0.0x
Saudi Aramco	-4.2%	0.9%	29.6%	29.1%	0.0x	0.1x	-0.1x	0.1x
Guinness Fund	**3.7%**	**7.8%**	**6.2%**	**6.8%**	**0.3x**	**0.2x**	**1.4x**	**1.2x**

Impact on the global oil macro outlook

As far as we can see, Saudi Aramco is not going to be an ‘oil growth story’. The information that we have seen leads us to believe that the global oil supply/demand outlook is not going to be negatively affected in any respect by this IPO.

- Saudi Aramco **remains the vehicle for Saudi oil policy** and thus it will be subject to OPEC quota controls and will continue to maintain a buffer of spare production capacity. The company currently has 10m b/day of oil production with estimated total oil production capacity of around 12m b/day.

- We believe that **Saudi Aramco will not deliver much oil production capacity growth** in the coming years. We understand that Saudi Aramco is planning to spend around 31% of its capital expenditure on oil/NGL production, implying a total spend of around $12.5bn pa. On the assumption that Saudi Aramco maintains its production capacity at current levels and develops reserves to replace those that are produced, we can make the following calculations:

    1. Saudi Aramco produces around 4 billion barrels of oil/NGL every year, so the company would need to develop its existing proved reserves to replace these produced barrels at a capital cost of around $3/bl based on this budget. It is plausible that Saudi Aramco can achieve this but we note that this cost is very much an industry leading aspiration and that it is very much lower than the underlying oil/NGL replacement costs of the super-majors or the Russian oils (estimated at $10-15/bl). At best, we estimate that Saudi Aramco is likely to maintain rather than grow its inventory of barrels available for production.

    2. Every year, Saudi Aramco’s oil fields will suffer a natural production capacity decline. Most oil companies suffer a 4-6% natural decline rate but we understand that many Saudi Aramco oil fields are still reasonably early in their development phase (i.e. ramp-up), so Saudi Aramco’s decline is likely to be at the lower end of the range. Assuming the $12.5bn of oil/NGL capex and a 4% decline, Saudi Aramco would need to replace existing capacity at a cost of around $27k per flowing barrel. This, again, is an industry leading cost level and lower, for example,

than the industry leading new non-OPEC oil field Johan Svedrup.

Valuation and equity story

The IPO process for Saudi Aramco will result in a final valuation for the company's shares. We do not intend to express a view on the valuation here but note numerous press reports indicating a wide valuation range of around $1.2trn to $2.3trn with a mid point of around $1.6trn. For illustration, here we present some key valuation metrics for Saudi Aramco and various large integrated oil company peers based on the reported mid point of $1.6 trn.

Summary valuation metrics based on $1.6trn market cap for Saudi Aramco

Source: Guinness Asset Management estimates, Bloomberg

	EV/EBITDA		P/E		P/B		Dividend yield		Free cash flow yield	
	2019	2020	2019	2020	2019	2020	2019	2020	2019	2020
BP	5.3x	4.9x	12.8x	11.6x	1.2x	1.2x	6.4%	6.4%	9.3%	10.6%
Chevron	6.0x	5.4x	18.6x	16.6x	1.4x	1.4x	4.0%	4.1%	7.9%	9.0%
ENI	4.2x	3.6x	15.1x	11.6x	1.0x	0.9x	5.8%	5.8%	7.1%	9.0%
Equinor	3.3x	2.7x	11.7x	9.3x	1.4x	1.3x	4.9%	5.1%	8.7%	11.3%
Exxon	7.5x	7.1x	15.6x	14.9x	1.4x	1.4x	5.0%	5.2%	3.7%	5.4%
OMV	4.9x	4.0x	10.1x	8.2x	1.4x	1.2x	3.6%	3.8%	13.7%	15.2%
RDShell	6.0x	5.8x	13.5x	12.6x	1.2x	1.2x	6.6%	6.7%	6.9%	7.8%
Repsol	5.1x	4.1x	11.6x	8.6x	0.7x	0.7x	6.2%	6.2%	4.7%	7.4%
TOTAL	5.7x	4.8x	12.6x	10.1x	1.4x	1.3x	5.1%	5.2%	7.9%	9.6%
CNOOC	4.4x	4.1x	10.2x	9.7x	1.0x	0.9x	6.7%	6.9%	7.1%	8.2%
Gazprom	4.0x	4.0x	4.0x	3.4x	0.4x	0.3x	7.2%	9.4%	4.1%	3.4%
Lukoil	2.7x	2.2x	5.2x	4.9x	0.8x	0.6x	4.3%	5.8%	15.0%	15.1%
Petrobras	6.2x	5.1x	11.1x	8.3x	1.1x	1.0x	2.8%	2.8%	8.7%	15.1%
PetroChina	3.9x	3.8x	10.3x	10.2x	0.5x	0.5x	5.7%	5.7%	4.1%	5.5%
Sinopec	3.7x	3.1x	10.6x	7.7x	0.6x	0.6x	10.0%	10.0%	8.3%	11.8%
Saudi Aramco (at $1.6trn)	8.3x	8.0x	17.3x	16.7x	5.5x	5.6x	4.5%	4.7%	4.4%	4.5%

- We see **Saudi Aramco's valuation as looking quite rich** versus the super-majors and also versus our modelled group of Emerging Market integrated oils and to the Guinness Global Energy fund as a whole (on our initial assessment based on a $60/bl Brent oil price).

- In terms of 2020 EV/EBITDA and P/E ratios, Saudi Aramco would likely be trading at around 8x and 17x. For reference, the Super Majors would be in a range of 5-7x and 10-17x respectively, whilst the Emerging Market integrated oils would be at only 2-5x and 4-10x respectively.

- **Saudi Aramco would be trading at just under a 5% dividend yield** for 2020. The Super Majors currently offer a range of 4-7% and the Emerging Market Oils offer 3-10%.

In conclusion, our research has confirmed that Saudi Aramco is definitely a 'one of a kind' company. Relative to our initial expectations, we find the company to be less oil price sensitive than expected (as a result of the progressive royalty regime and its lower oil production growth outlook) and more growth-oriented towards chemicals, downstream and natural gas production. Despite its size and dominance, Saudi Aramco is not immune to global economic realities and its success will rely on its ability to balance the needs of its majority shareholder in maintaining a global oil balance together with shareholders requirements of balancing annual cash flows, dividends and acceptable levels of reinvestment.

1) PERFORMANCE Guinness Global Energy Fund

The main index of oil and gas equities, the MSCI World Energy Index (net return), fell by 1.6% in October, while the MSCI World Index (net return) rose by 2.5%. The Fund was down by 2.4% (class E) in the month, underperforming the MSCI World Energy index by 0.8% (all in US dollar terms).

Within the Fund, October's strongest performers were Gazprom, Valero Energy Corp, OMV, Helix and Enbridge while the weakest performers were Unit Corp, Oasis, Sunpower, Devon and Encana.

Performance (in USD) 31/10/2019

Annualised

% returns	1 year	3 years	5 years	10 years	1999 to date
Guinness Global Energy	-15.0	-4.1	-8.6	-2.0	8.3
MSCI World Energy Index	-9.0	0.3	-4.0	1.1	5.4

Calendar year

% returns	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007
Guinness Global Energy	2.5	-19.7	-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	4.5	-15.8	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 position switches during the month but the portfolio was actively rebalanced.

Sector Breakdown

The following table shows the asset allocation of the Fund at **October 31 2019**.

Asset allocation as %NAV	Current	Last year end	*Change*	Previous year ends					
	Oct-19	Dec-18		Dec-17	Dec-16	Dec-15	Dec-14	Dec-13	Dec-12
Oil & Gas	**98.0%**	**96.7%**	***1.3%***	**98.4%**	**96.7%**	**95.1%**	**93.7%**	**93.6%**	**98.6%**
Integrated	52.2%	46.4%	*5.8%*	42.9%	46.4%	41.5%	37.3%	38.4%	39.1%
Exploration & Production	28.3%	35.8%	*-7.5%*	36.9%	35.8%	36.5%	36.2%	35.2%	41.6%
Drilling	0.3%	2.2%	*-1.9%*	1.9%	2.2%	1.5%	3.3%	7.0%	7.4%
Equipment & Services	8.8%	8.6%	*0.2%*	9.5%	8.6%	11.4%	13.4%	9.8%	7.1%
Storage & Transportation	4.1%	0.0%	*4.1%*	3.5%	0.0%	0.0%	0.0%	0.0%	0.0%
Refining & Marketing	4.3%	3.7%	*0.6%*	3.7%	3.7%	4.2%	3.5%	3.1%	3.4%
Solar	0.7%	0.9%	*-0.2%*	1.4%	0.9%	4.7%	3.7%	2.6%	1.2%
Coal & Consumable Fuels	0.0%	0.0%	*0.0%*	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Construction & Engineering	0.0%	0.0%	*0.0%*	0.0%	0.0%	0.0%	0.0%	1.2%	0.6%
Cash	1.3%	2.4%	*-1.1%*	0.2%	2.4%	0.2%	2.6%	2.6%	-0.4%

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

The Fund at October 31 2019 was on a price to earnings ratio (P/E) for 2019 of 12.3x versus the S&P 500 Index at 19.1x as set out in the following table:

	2018	2019	2020
Fund P/E	10.8	12.3	11.7
S&P 500 P/E	20.0	19.1	17.1
Premium (+) / Discount (-)	*-46%*	*-36%*	*-32%*
Average oil price (Brent/WTI $/bbl)	68	61	

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

Portfolio holdings

Our integrated and similar stock exposure (c.52%) 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, Equinor, Repsol and OMV. At October 31 2019 the median P/E ratios of this group were 12.6x/10.2x 2019/2020 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.28%) 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 (EnCana, Devon and Oasis), with four other names (Apache, Occidental, ConocoPhillips, Noble Energy) having a mix of US and international production and one (Tullow) which is African focused. One of the key metrics behind a number of the E&P stocks held is low enterprise value / proven reserves. Almost all of the US E&P stocks held also provide exposure to North American natural gas.

We have exposure to four (pure) emerging market stocks in the main portfolio, though one is a half-position, and in total represent 12% of the portfolio. Two are classified as integrateds (Gazprom and PetroChina) and two as E&P companies (CNOOC and SOCO International). Gazprom is the Russian national oil and gas company which produces approximately a quarter of the European Union gas demand and trades on 4.1x 2019 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 modest exposure to oil service stocks, which comprise around 9% of the portfolio. The stocks we own are mainly diversified 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 30 2019 (for compliance reasons disclosed one month in arrears)

Guinness Global Energy Fund (30 September 2019)			Total return (USD)					P/E			EV/EBITDA		
Stock	% of NAV	Market Cap USD	3 months	6 months	1 year	3 years	5 years	2018	2019E	2020E	2018	2019E	2020E
Integrated Oil & Gas													
Chevron Corp	3.7%	220,236	-2%	1%	12%	30%	22%	14.7x	17.1x	15.0x	5.9x	6.6x	6.1x
Royal Dutch Shell PLC	3.8%	228,125	-4%	-9%	5%	42%	6%	11.4x	12.4x	10.3x	5.5x	5.5x	5.1x
BP PLC	3.9%	126,357	-10%	-12%	5%	31%	19%	10.7x	12.1x	10.9x	5.3x	4.9x	4.6x
Total SA	4.1%	135,641	-3%	-15%	3%	29%	5%	10.7x	10.8x	9.5x	5.4x	5.0x	4.7x
ENI SpA	3.8%	54,802	-8%	-14%	3%	25%	-14%	11.6x	12.9x	10.7x	3.4x	3.6x	3.4x
Equinor ASA	4.2%	62,538	-11%	-29%	-6%	30%	-11%	9.4x	11.8x	10.2x	2.9x	3.1x	2.7x
Repsol SA	4.1%	24,784	-5%	-16%	1%	37%	-11%	9.4x	9.0x	7.5x	4.7x	4.6x	4.2x
OMV AG	3.9%	17,675	3%	-1%	28%	105%	91%	10.3x	9.3x	8.6x	4.7x	4.3x	4.0x
	31.4%												
Integrated / Oil & Gas E&P - Canada													
Suncor Energy Inc	4.0%	47,654	-1%	-15%	16%	25%	3%	15.0x	12.2x	13.5x	6.2x	6.0x	6.1x
Canadian Natural Resources Ltd	4.2%	30,594	-1%	-15%	14%	-8%	-19%	12.6x	10.1x	13.6x	6.1x	5.9x	6.1x
Imperial Oil Ltd	3.9%	19,365	-3%	-17%	5%	-12%	-40%	12.6x	12.9x	14.6x	6.8x	7.5x	7.3x
	12.2%												
Integrated Oil & Gas - Emerging market													
PetroChina Co Ltd	3.9%	151,083	-17%	-34%	-14%	-14%	-54%	11.8x	11.9x	11.1x	4.7x	5.0x	4.9x
Gazprom PJSC	3.6%	80,395	64%	48%	67%	98%	31%	3.7x	3.5x	3.8x	3.1x	3.4x	3.4x
	7.5%												
Oil & Gas E&P													
Occidental Petroleum Corp	3.8%	39,151	-31%	-43%	-24%	-29%	-39%	9.0x	16.1x	18.4x	5.1x	5.1x	3.4x
ConocoPhillips	4.0%	61,224	-14%	-25%	-7%	39%	-14%	12.8x	13.9x	13.4x	4.6x	4.8x	4.9x
Apache Corp	3.2%	9,125	-25%	-45%	0%	-57%	-70%	15.3x	159.0x	40.8x	4.1x	5.1x	4.8x
Devon Energy Corp	3.1%	9,353	-23%	-39%	8%	-44%	-62%	15.9x	17.5x	13.1x	3.7x	4.1x	4.0x
Noble Energy Inc	3.1%	10,235	-8%	-27%	22%	-34%	-65%	23.3x	n/a	41.5x	6.3x	7.6x	5.6x
EnCana Corp	2.7%	5,786	-36%	-65%	-20%	-55%	-77%	6.8x	7.6x	7.3x	6.6x	4.1x	3.8x
Oasis Petroleum Inc	1.3%	1,085	-43%	-76%	-37%	-70%	-92%	12.3x	101.8x	n/a	4.3x	4.3x	4.3x
	21.1%												
International E&Ps													
CNOOC Ltd	3.8%	67,530	-14%	-18%	5%	43%	13%	8.9x	8.7x	8.6x	3.0x	3.4x	3.3x
Tullow Oil PLC	1.8%	3,607	-14%	-22%	18%	-4%	-70%	23.7x	15.6x	11.9x	5.4x	5.4x	5.3x
Soco International PLC	0.5%	310	-5%	-24%	-2%	-47%	-84%	23.8x	28.1x	21.8x	3.8x	2.9x	2.3x
	6.1%												
Midstream													
Enbridge Inc	3.8%	71,120	0%	16%	18%	-6%	-7%	17.8x	17.5x	17.4x	13.5x	12.9x	12.4x
	3.8%												
Drilling													
Unit Corp	0.5%	173	-76%	-87%	-76%	-82%	-94%	3.4x	n/a	5.6x	3.2x	4.1x	3.3x
	0.5%												
Equipment & Services													
Halliburton Co	3.2%	16,275	-35%	-52%	-27%	-55%	-68%	10.2x	14.5x	11.7x	6.3x	7.1x	6.5x
Helix Energy Solutions Group Inc	1.8%	1,148	2%	-18%	49%	-1%	-63%	36.6x	27.0x	20.6x	10.1x	9.1x	7.4x
Schlumberger Ltd	3.3%	45,224	-19%	-41%	-1%	-52%	-61%	21.0x	23.0x	17.9x	9.2x	9.3x	8.5x
	8.2%												
Solar													
Sunpower Corp	0.9%	1,481	69%	50%	121%	23%	-68%	n/a	n/a	51.0x	28.7x	22.7x	12.9x
	0.9%												
Oil & Gas Refining & Marketing													
Valero Energy Corp	3.9%	35,315	3%	-22%	18%	80%	121%	13.9x	17.1x	8.9x	7.6x	8.4x	5.8x
	3.9%												
Research Portfolio													
Cluff Natural Resources PLC	0.2%	27	-39%	-33%	-37%	-70%	-70%	n/a	n/a	n/a	n/a	n/a	n/a
EnQuest PLC	0.6%	391	-5%	-49%	-16%	-13%	-83%	4.7x	2.7x	2.3x	3.9x	3.1x	3.2x
JKX Oil & Gas PLC	0.1%	62	-48%	-23%	-26%	61%	-53%	18.6x	n/a	n/a	2.7x	n/a	n/a
Reabold Resources PLC	0.6%	53	77%	16%	41%	36%	-78%	n/a	n/a	n/a	n/a	n/a	n/a
Shandong Molong Petroleum Machinery Co Ltd	0.1%	341	-28%	-19%	-19%	-69%	-79%	n/a	n/a	n/a	n/a	n/a	n/a
Diversified Gas & Oil Company	0.5%	859	-16%	-8%	-3%	n/a	n/a	8.8x	6.8x	8.0x	10.8x	5.5x	5.6x
	2.0%												
Cash	**2.3%**												
Portfolio	**100.0%**							**11.2x**	**12.4x**	**11.3x**	**5.1x**	**5.2x**	**4.8x**

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 since 2015:

	2015	2016	2017	2018	2019E	2020E
					IEA	*IEA*
World Demand	***95.3***	***96.4***	***98.2***	***99.3***	***100.3***	***101.5***
Non-OPEC supply (inc NGLs)	*59.8*	*59.2*	*60.1*	*62.9*	*64.8*	*67.0*
OPEC NGLs	*5.2*	*5.4*	*5.5*	*5.5*	*5.6*	*5.6*
Non-OPEC supply plus OPEC NGLs	**65.0**	**64.6**	**65.6**	**68.4**	**70.4**	**72.6**
Call on OPEC (crude oil)	**30.3**	**31.8**	**32.6**	**30.9**	**29.9**	**28.9**
Congo supply adjustment	0.3	0.3	0.3	0.3	0.3	0.3
Gabon supply adjustment	0.2	0.2	0.2	0.2	0.2	0.2
Eq Guinea supply adjustment	0.1	0.1	0.1	0.1	0.1	0.1
Call on OPEC-11 (crude oil)	**29.7**	**31.2**	**32.0**	**30.3**	**29.3**	**28.3**

Source: 2006 - 2014: IEA oil market reports; 2015 - 19: October 2019 Oil market Report
OPEC-11 = Algeria; Angola; Ecuador; Iran; Iraq; Kuwait; Libya; Nigeria; Saudi Arabia; UAE; Venezuela

Global oil demand in 2018 was 12m 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 1.0m b/day in 2019, which would take oil demand to an all-time high of 100.3m b/day.

OPEC

The last five years have proved a testing time for OPEC. They have tried to keep prices strong enough that OPEC economies are not running excessive deficits, whilst not pushing the price too high and over-stimulating non-OPEC supply.

The effect of $100+ bbl oil, enjoyed for most of the 2011-2014 period, emerged in 2014 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. OPEC met in late 2014 and responded to rising non-OPEC supply with a significant change in strategy to one that prioritised market share over price. Post the November 2014 meeting, OPEC not only maintained their quota but also raised production significantly, up over 18 months by 2.5m b/day. This contributed to an oversupplied market in 2015 and 2016.

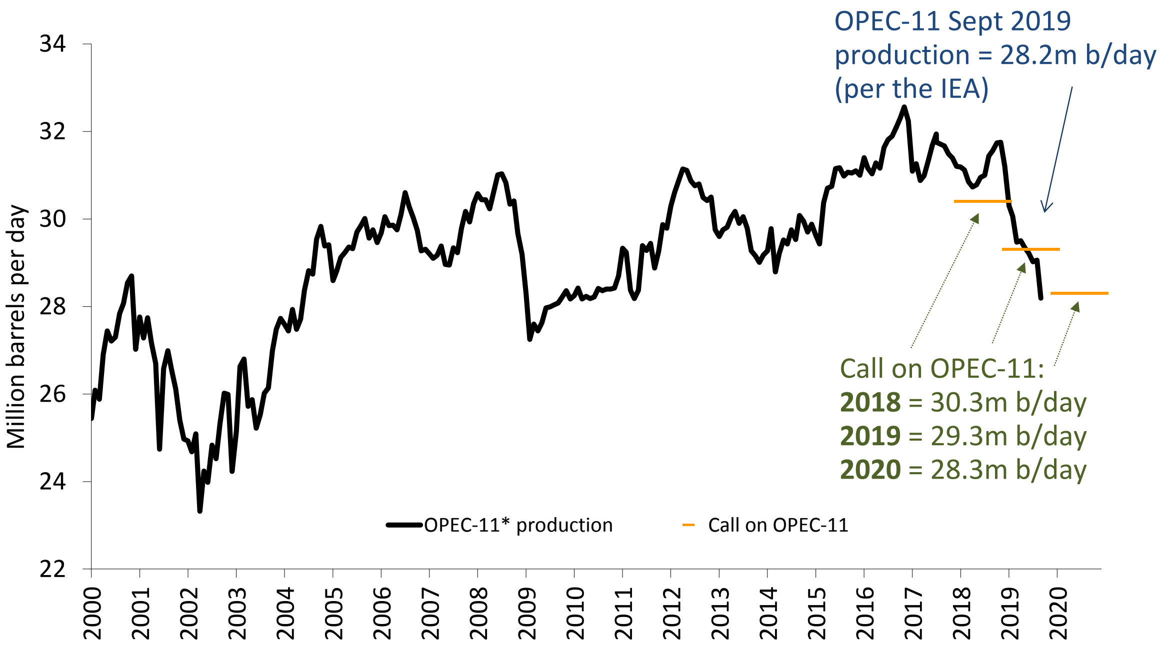
In November 2016, faced with sharply lower oil prices, OPEC stepped back from their market share stance, announcing plans for the first production cut since 2008, opting for a new production limit of 32.5m b/day. The announcement represented a cut of 1.2m b/day. There was also an understanding that non-OPEC, including Russia, would cut production by 0.6m b/day, taking the total reduction to 1.8m b/day. 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.

('000 b/day)	30-Nov-14	31-Dec-16	31-Oct-19	Current vs Nov 2014 (OPEC hold mkt share)	Current vs Dec 2016 (OPEC cut production)
Saudi	9,650	10,480	**9,880**	230	-600
Iran	2,780	3,730	**2,110**	-670	-1,620
Iraq	3,370	4,630	**4,680**	1,310	50
UAE	2,800	3,070	**3,070**	270	0
Kuwait	2,790	2,860	**2,670**	-120	-190
Nigeria	1,970	1,500	**1,910**	-60	410
Venezuela	2,350	2,080	**690**	-1,660	-1,390
Angola	1,640	1,670	**1,340**	-300	-330
Libya	580	630	**1,180**	600	550
Algeria	1,100	1,110	**1,080**	-20	-30
Ecuador	561	550	**420**	-141	-130
OPEC-11	**29,591**	**32,310**	**29,030**	**-561**	**-3,280**

Source: Bloomberg; Guinness Asset Management

The last eighteen months has continued to be a volatile time for OPEC. For the first half of 2018, a steep production decline from Venezuela and the promise of lower Iranian exports lead other OPEC members to raise supply, designed to prevent oil prices spiking too high. Towards the end of the year, it became apparent that OPEC had over-compensated and risked oversupplying the market in 2019. In December 2018, OPEC met in Vienna and, together with non-OPEC, announced a proposed cut of 1.2m b/day starting in January 2019 and lasting for an initial period of six months. It was proposed that OPEC (excluding Libya, Venezuela and Iran) cut total production by 0.8m b/day while non-OPEC (led predominantly by Russia) cut a total of 0.4m b/day. In July 2019, the existing quota cuts were extended to March 2020.

Figure 7: OPEC-12 apparent production vs call on OPEC 2000 – 2019



Source: IEA Oil Market Report (October 2019 and prior); Guinness estimates

OPEC's actions in recent years demonstrate a commitment 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 ($75-80/bl is needed to close the gap fully), whilst not spiking the oil price too high and over-stimulating non-OPEC supply. Longer term, we believe that Saudi seek a 'good' oil price, in excess of current levels to balance their fiscal needs, but they realise that patience is required to achieve that goal.

Overall, we reiterate two important criteria for Saudi:

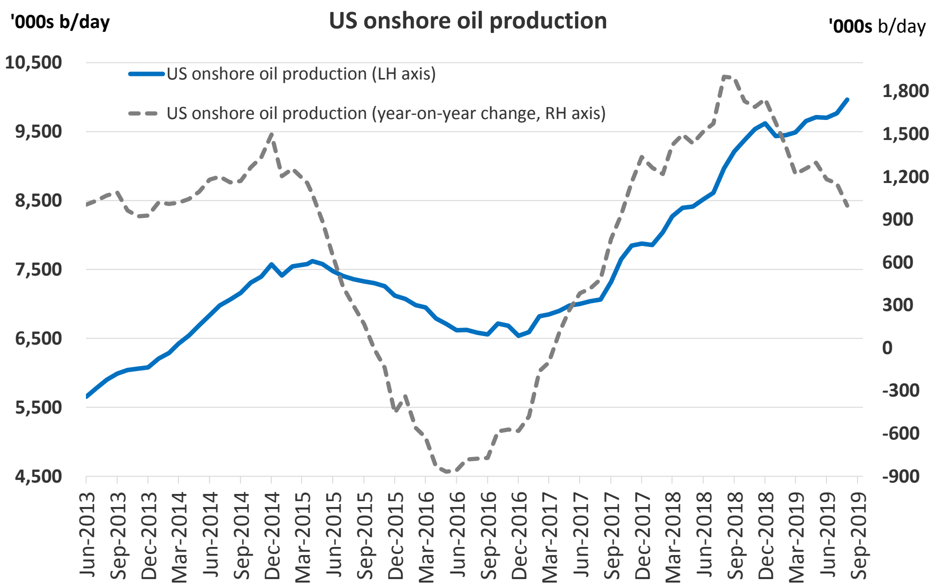
1. Saudi is interested in the average price of oil that they get, they have a longer investment horizon than most other market participants
2. Saudi wants to maintain a balance between global oil supply and demand to maintain a price that is acceptable to both producers and consumers

Nothing in the market in recent years has changed our view that OPEC can put a floor under the price – as they did in 2016, 2008, 2006, 2001, 1998 – and again in late 2018. 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 2008-2018.

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 7m 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.

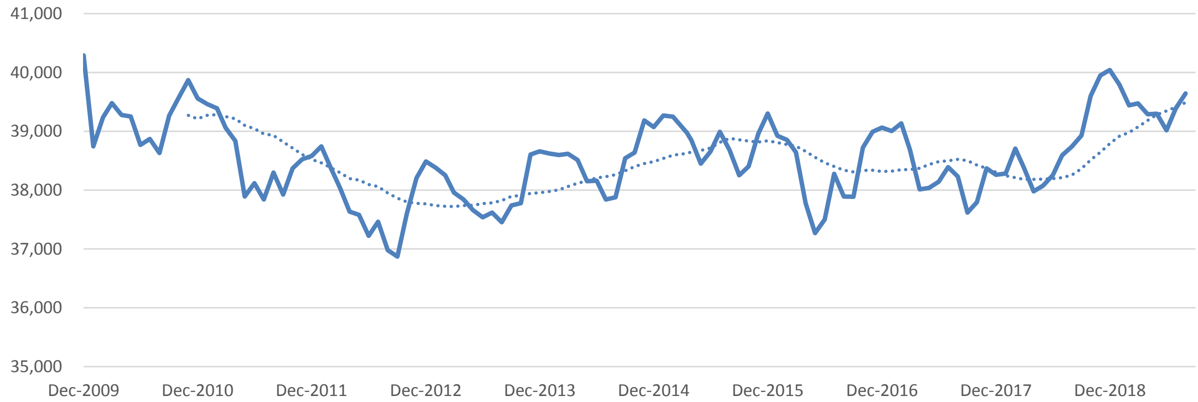


Source: EIA; Guinness Asset Management

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 it is now well above 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 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 $50-60/bl world are far lower than in a $100/bl world, but with efficiency improvements, enough to see growth sustaining.

Offsetting US onshore shale oil growth, we expect to see non-OPEC supply growth outside the US slow, 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/bl+) have continued to come onstream. However, the slowdown in investment post 2014 creates the likelihood that non-OPEC (ex US) production will struggle to grow into the start of the 2020s. On a ten year view, it is interesting to note that non-OPEC (ex US) has essentially been flat, as new investment has simply offset the decline profiles of existing production:

Figure 8: Non-OPEC (ex US onshore) oil production



Source: PIW; Guinness Asset Management

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 2019 oil demand growth will be 1.0m b/day, taking demand to over 100m 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 2019 comprises an increase in non-OECD demand of 1.1m b/day and a decline in OECD demand of 0.1m b/day. The components of this non-OECD demand growth can be summarised as follows:

Figure 9: Non-OECD oil demand

m b/day	Demand								Growth							
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019e**	**2020e**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019e**	**2020e**
Asia	22.1	22.8	24.1	25.0	26.2	27.0	27.8	28.6	0.7	0.7	1.3	0.9	1.2	0.8	0.8	0.8
Middle East	7.9	8.4	8.5	8.5	8.4	8.3	8.3	8.3	0.1	0.5	0.1	0.0	-0.1	-0.1	0.0	0.0
Latin America	6.7	6.8	6.7	6.4	6.5	6.4	6.4	6.4	0.3	0.1	-0.1	-0.3	0.1	-0.1	0.0	0.0
FSU	4.7	4.66	4.6	4.5	4.6	4.7	4.9	4.9	0.1	0.0	-0.1	0.0	0.1	0.1	0.2	0.0
Africa	3.9	3.8	4.2	4.3	4.2	4.2	4.3	4.4	0.1	-0.1	0.4	0.1	-0.1	0.0	0.1	0.1
Europe	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
Total	**46.0**	**47.2**	**48.7**	**49.5**	**50.6**	**51.5**	**52.5**	**53.5**	**1.3**	**1.2**	**1.6**	**0.7**	**1.2**	**0.8**	**1.1**	**0.9**

Source: IEA Oil Market Report (October 2019)

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 will also grow rapidly.

OECD demand in 2019 is forecast to be down by 0.2m 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% per year. Nonetheless, general global economic weakness in the early part of 2019 is steadily being reflected in lower expectations of OECD demand growth in 2019.

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, the development of alternative fuels 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.

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 1.8m in 2018, up from 1.2m in 2017. We expect to see EV sales accelerate in 2019 to around 2.5m, or 3% of total global sales. Even applying an aggressive growth rate to EV sales, we see EVs comprising only around 0.7% of the global car fleet in 2020. Looking further ahead, we expect the penetration of EVs to accelerate, causing global gasoline demand to peak at some point in the second half of the 2020s. However, owing to the weight of oil demand that comes from sources other than passenger vehicles (around 70%), which we expect to continue growing linked to GDP, we expect total oil demand not to peak until the mid 2030s.

Conclusions about oil

The table below summarises our view by showing our oil price forecasts for WTI and Brent in 2019 against their historic levels, and rises/falls in percentage terms that we have seen in the period from 2002 to 2018.

Figure 10: 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	2019
WTI	30	33	38	49	66	75	82	104	68	84	99	94	98	93	49	45	51	65	58
Brent	30	32	35	46	64	75	82	103	67	84	115	112	108	99	52	45	54	72	60
Brent/WTI (12m MAV)	**30**	**33**	**37**	**48**	**65**	**75**	**82**	**104**	**68**	**84**	**107**	**103**	**103**	**96**	**51**	**45**	**53**	**68**	**59**
Brent/WTI y-on-y change (%)		8%	12%	30%	37%	15%	9%	26%	-35%	24%	27%	-4%	0%	-7%	-47%	-11%	17%	30%	-14%
Brent/WTI (5yr MAV)	30	25	32	37	42	51	61	75	79	82	89	93	93	99	92	80	69	63	55

We expect Brent oil to trade in a $55-65/bl range in the near term, supported at the lower end by OPEC. If this price range persists, we expect North American unconventional supply to sustain growth. We believe that the 'call' on unconventional supply, however, is likely to grow over the next few years as conventional non-OPEC supply declines.

The world oil bill at around $70/bl represents 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, something around $70/bl.

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 2018, 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	2018	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) was 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 were 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 $2.50/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 to 2025, 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. Beyond the mid-2020s, we expect power generation from gas to face stronger competition from renewables.

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.

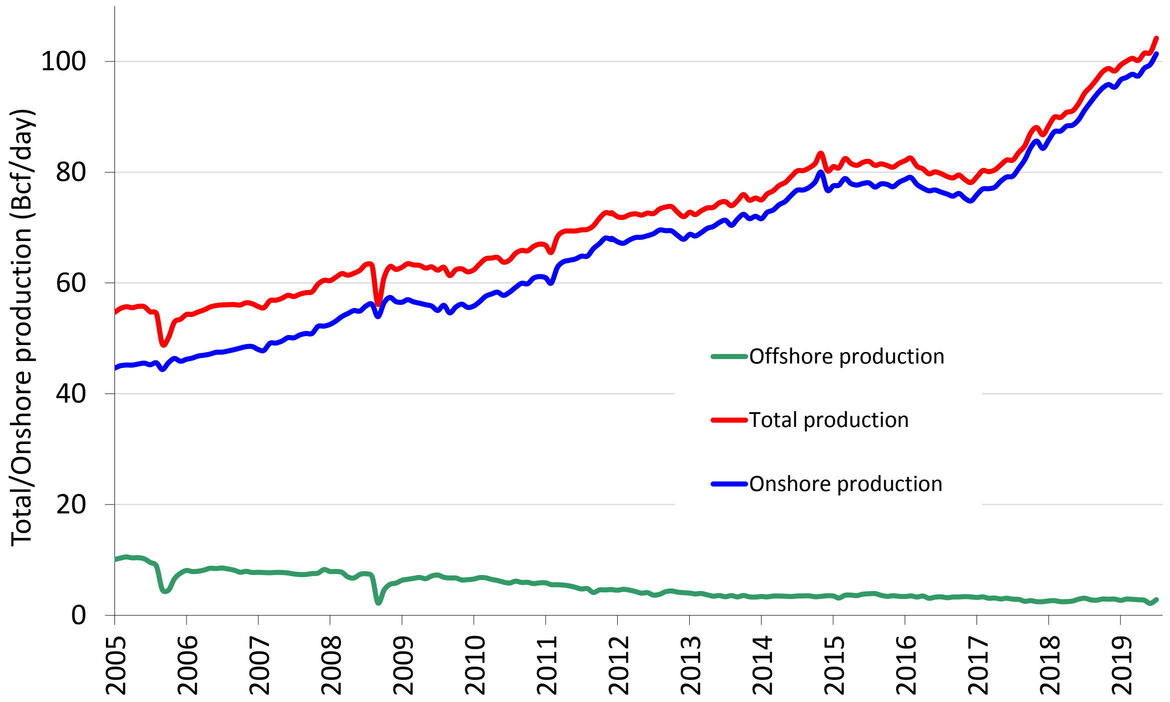
The supply side fundamentals for natural gas in the US are driven by 3 main moving parts: onshore and offshore domestic production, and pipeline imports of gas from Canada. Of these, onshore supply is the biggest component, making up over 85% of total supply.

Bcf/day	2007	2008	*2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018	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 130 at the end of October 2019. 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 (July 2019) at 99.2 Bcf/day, far above the 57.4 Bcf/day peak in November 2008 before the rig count collapsed.

Figure 11: US natural gross gas production 2005 – 2019 (Lower 48 States)



Source: EIA 914 data (August 2019 published in October 2019)

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.

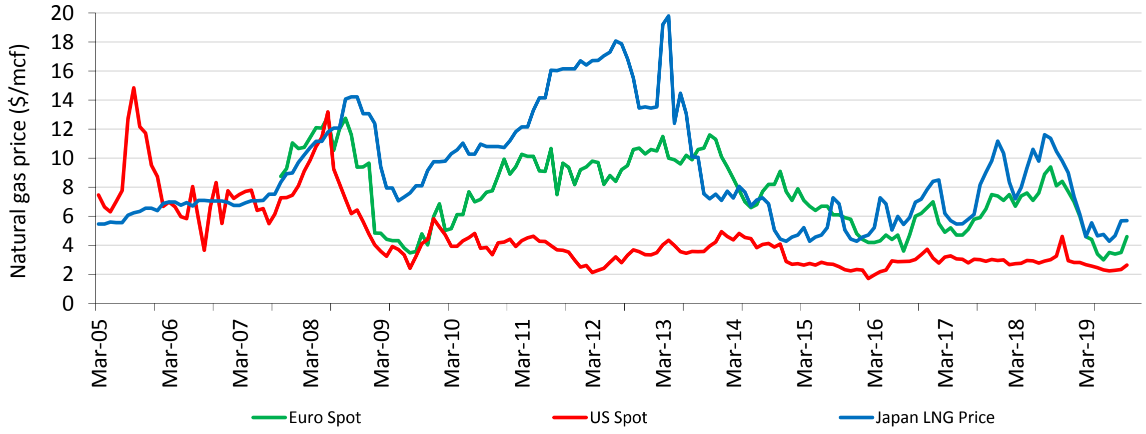
Associated gas production declined in 2016 with the fall of shale oil production, but with US oil supply now growing well again, so associated gas production has picked up. Generally, we expect to see rates of around 2-3 Bcf/day of associated gas per 1m b/day of oil production growth.

The Marcellus/Utica region, which includes the largest producing gas field in the US and the surrounding region, reached production of around 29 Bcf/day in 2018, with growth accelerating further in 2019 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/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 small premium to the US gas price (c.$4/mcf versus c.$2.30/mcf). Asian spot LNG prices fell sharply down to around $4.50/mcf at the start of 2016 but have since averaged around $8/mcf (though currently around $5/mcf on seasonal weakness) as Chinese gas demand strengthens. The implied economics for US LNG exports into Europe and Asia are reasonably attractive assuming international prices are over $5/mcf.



Source: Bloomberg (Oct 2019)

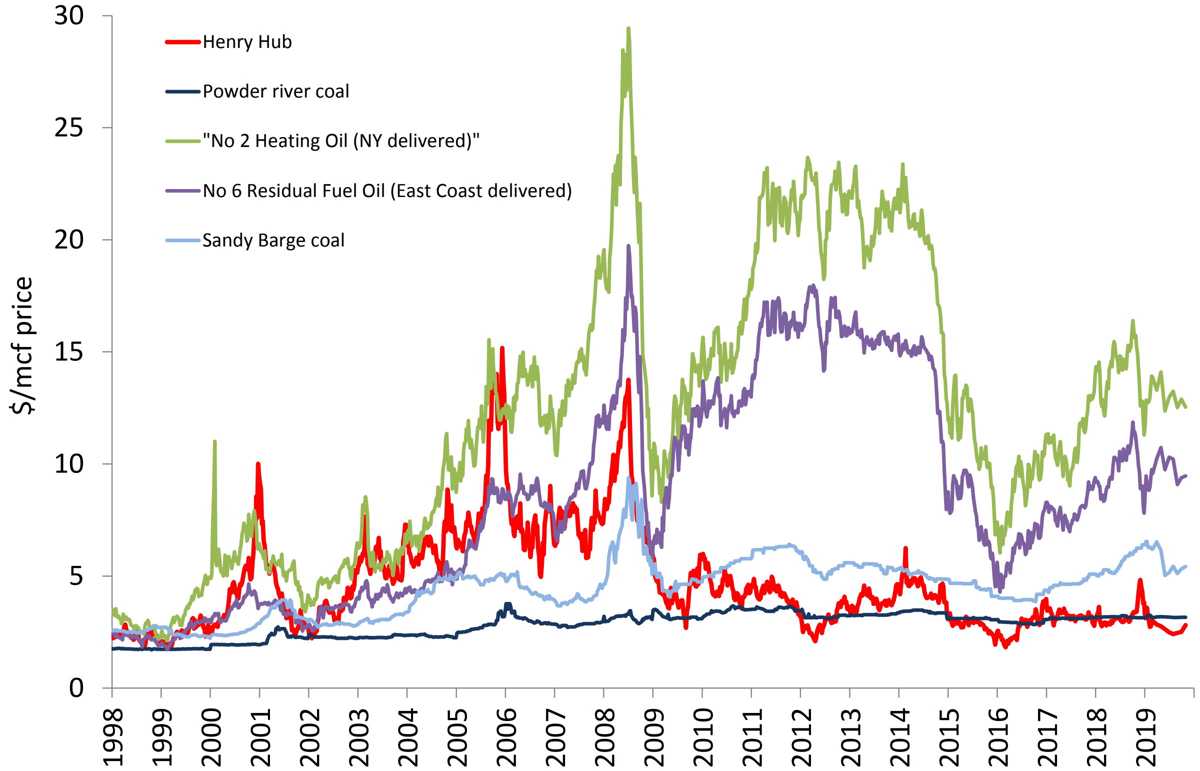
Relationship with oil and coal

The oil/gas price ratio ($ per bbl WTI/$ per mcf Henry Hub) of around 20x at the end of October 2019 sits well above 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 12: 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 (October 2019)

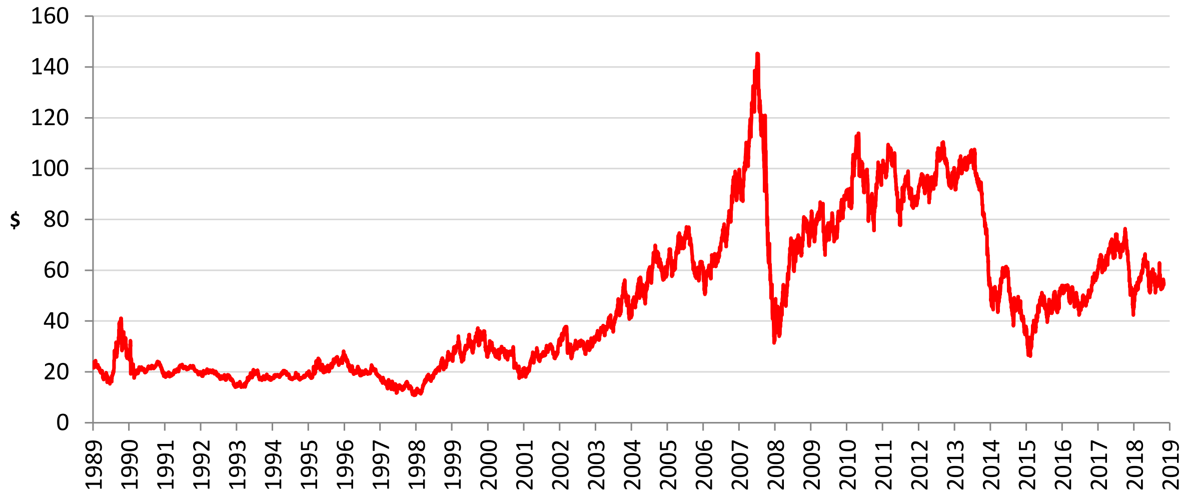
Conclusions about US natural gas

Bcf/day	2007	2008	*2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018	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 any 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 2018 natural gas prices (at $3.07) were around 75% higher the April 2012 low, and we suspect that the (full cycle) marginal cost of supply is now around $3/mcf. However, the continued growth of associated gas (from shale oil) will probably pin the price closer to $2.50/mcf for the foreseeable future. Longer term we expect the price to normalise to nearer $3/mcf.

3. APPENDIX Oil and gas markets historical context

Figure 13: 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.

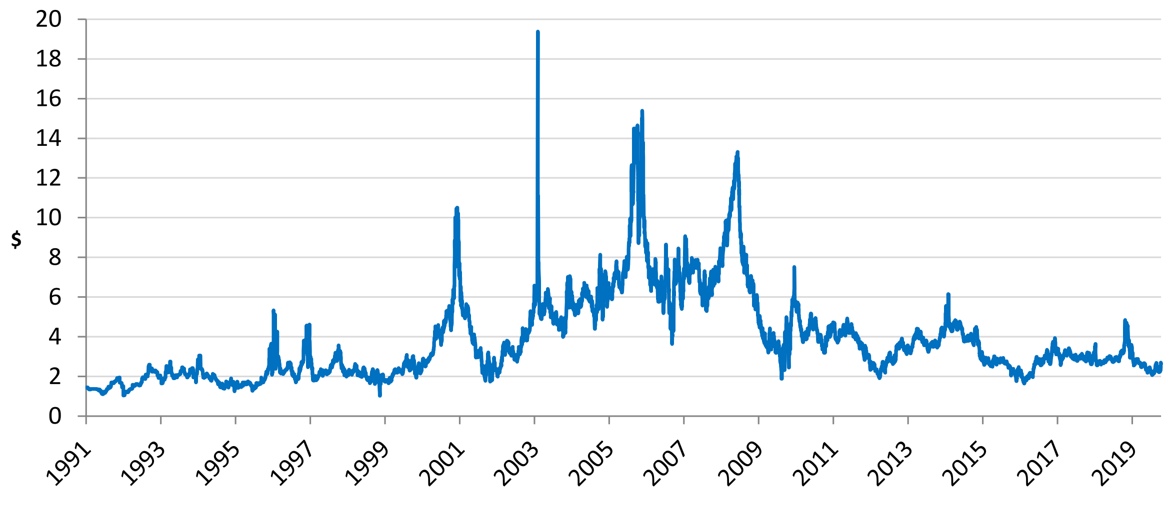
Continued expectations of a supply crunch by the end of the decade, coupled with increased speculative activity in oil markets, contributed to the oil price surging past $90 in the final months of 2007 and as high as $147 by the middle of 2008. This spike was brought to an abrupt end by the collapse 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, the new oil cycle is characterised by good demand growth but a reduced cost curve which has stimulated non-OPEC supply, pinning average prices in the $50-70/bl range once again.

Figure 14: 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, though the development of the LNG industry is creating a greater linkage.

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