THE GUINNESS GLOBAL ENERGY REPORT

Developments and trends for investors in the global energy sector | February 2020

GUINNESS GLOBAL ENERGY FUND

Fund size: $166 m (31.01.2020)

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 JANUARY

OIL

Brent and WTI fell as coronavirus hit demand expectations

Brent and WTI were weaker over the month, down $11bl/$10bl to close at $52/56. Fears around the impact of the coronavirus on global oil demand were front and centre, with reports that Chinese oil demand has been curtailed by as much as 3m b/day (-20%). Overall demand in 2020 may be hit by 0.5m-1m b/day. OPEC are formulating a response to keep the oil market in balance.

NATURAL GAS

US, European and Asian gas prices weaker

Henry Hub prices were weaker over the month, falling hard in the last few days of January to close at $1.84/mcf. The US gas market is looking in better balance than in the fourth quarter of 2019, but coronavirus impact on demand is a concern in this market also.

EQUITIES

Energy underperforms the broad market in January

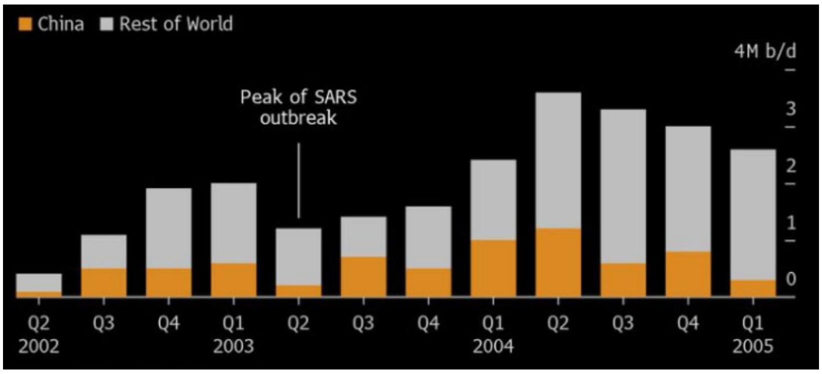
The MSCI World Energy Index (net return) fell by 9.1% in January, underperforming the MSCI World Index (net return) which fell by 0.6% over the month (all in US dollar terms).

CHART OF THE MONTH

Assessing the impact of the coronavirus on oil demand

The trajectory of the coronavirus and its ultimate impact on global oil demand is an unknown. Looking back at the SARS crisis in 2003, we can see that at the peak of the outbreak in Q2, oil demand growth fell from around 2.2m b/day to around 1.2m b/day – with seemingly a full recovery by the end of the year. At that time, Chinese oil demand accounted for about one quarter to one third of global oil demand growth. Today, around half of global demand growth comes China, and this, together with absolute Chinese oil demand having more than doubled since 2003, leads to the potential for a greater oil consumption shock on this occasion.

Global and China oil demand growth during the SARS crisis (m b/day)



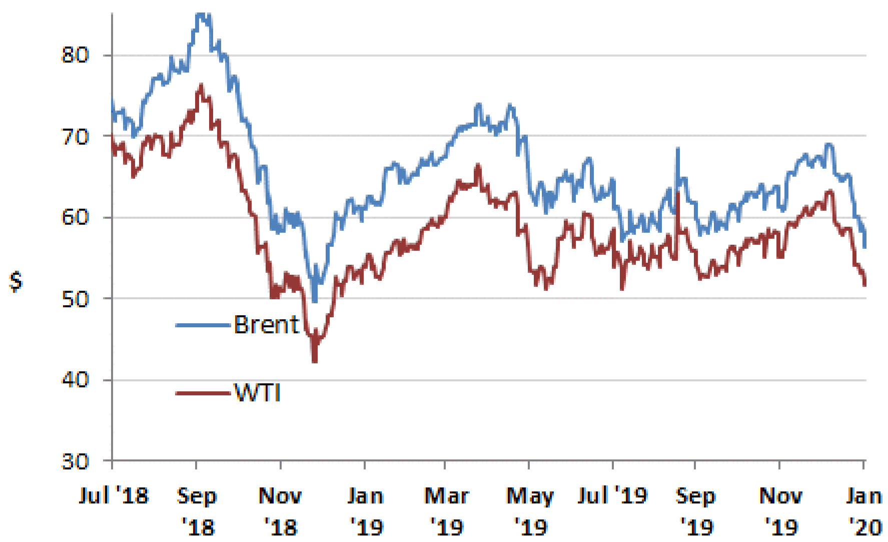
Source: Bloomberg; IEA; Guinness Asset Management

Contents

1. JANUARY IN REVIEW

i) Oil market

Figure 1: Oil price (WTI and Brent $/barrel) 18 months July 31 2018 to January 31 2020



Source: Bloomberg LP

The West Texas Intermediate (WTI) oil price started January at $61.1/bl, traded up over the first week of the month (reaching $63.3/bl on the 6th) before pulling back sharply to close at $51.6/bl. WTI averaged $58/bl in 2019, having averaged $65/bl in 2018, $51/bl in 2017 and $43/bl in 2016.

Brent oil traded in a similar shape, opening at $66.4/bl, trading up to over $69/bl before closing the month down at $56.3/bl. Brent averaged $64/bl in 2019, versus $72/bl in 2018. The gap between the WTI and Brent benchmark oil prices narrowed slightly over the month, ending January at around $4.8/bl, versus over $9/bl at some points in 2019.

Factors which strengthened WTI and Brent oil prices in January:

- **US/Iran political tensions**
  The strength in oil prices over the first few days in January can be attributed to an escalation of tensions between Iran and the US. On January 3, the US announced that they had carried out the assassination on Iraqi soil of Iranian General Qassim Suleimani. This action has raised fears of Iranian reprisals, including the possible targeting of oil facilities and oil transit in the region. There is also concern over a destabilisation of Iraq, where oil production is close to an all-time high.

- **Libyan production outages**
  Libya's conflict between Khalifa Haftar and his Libyan National Army and the UN-recognised Government of National Accord is again spilling over into the oil industry. Average production in January remained over 1m b/day, but in the last week of January, it is thought that production dropped to around 0.3m b/day. We are not aware that the conflict has caused any physical damage to oil facilities, so we would expect a swift recovery in export volumes when a resolution is found.

- **OPEC+ production cuts**
  At their December 2019 meeting, OPEC+ (OPEC plus select non-OPEC members) resolved to cut 0.5m b/day from production, starting in January. In the event, OPEC production for January, looks to be down by around 0.2m b/day, supported by a small reduction from Russia. It tends to take two to three months for production cuts to then filter through to imports on the US Gulf Coast.

Factors which weakened WTI and Brent oil prices in January:

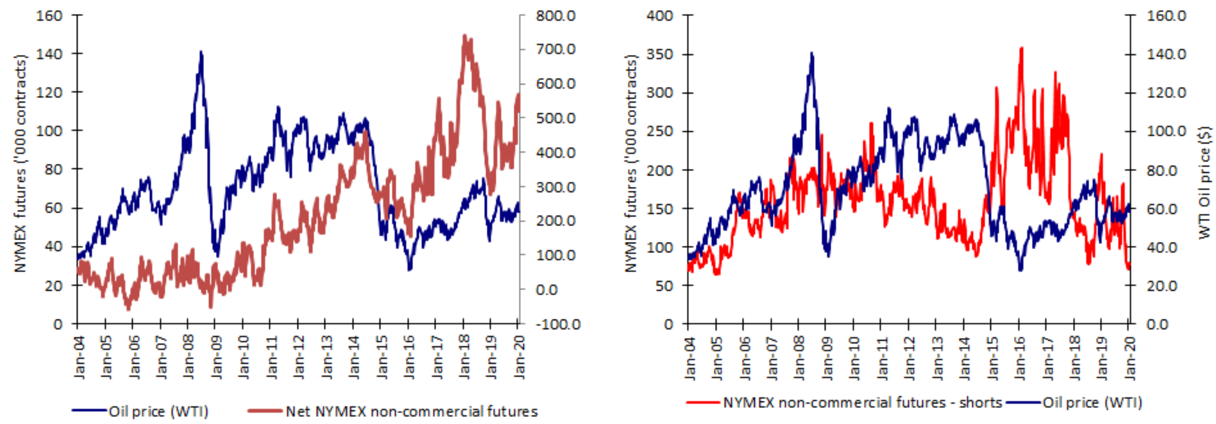
- **Fears around the impact on demand from the coronavirus**
  The major event in world markets in January was news of the spread of the novel coronavirus (2019-nCoV) in China and to other parts of the world. The spread of coronavirus has not been declared a pandemic, but appears to be the most serious new viral outbreak since SARS in 2003. The outbreak, which was first reported as coming from Wuhan in Hubei province, is causing major disruption to the Chinese economy, as authorities try to stop its spread. The impact on oil demand in China is likely to be pronounced, with consumption down as much as 20% (3m b/day) at the time of writing, jet fuel being the biggest casualty. As cases of coronavirus multiply elsewhere in the world, we would expect oil demand to slow elsewhere, particularly since preventive measures will slow the volume of travel in most regions. The overall impact of the coronavirus on oil demand is unknowable. By comparison, SARS dented Chinese oil demand in 2003 by around 0.3 b/day. Given the expansion of the Chinese economy since then, and the coordinated prevention measures now occurring elsewhere, it would not be surprising to see 2020 global oil demand dented by 0.5m-1m b/day.

- **US onshore supply growth staying strong in November (latest data)**
  The latest EIA production data showed a 101,000 b/day onshore oil production increase in November 2019 (latest data point), holding year-on-year growth at around 0.9m b/day. That said, the US oil directed rig count has dropped slightly since then, ending January at 675 rigs versus 678 rigs active on average in November.

Speculative and investment flows

The New York Mercantile Exchange (NYMEX) net non-commercial crude oil futures open position was 521,000 contracts long at the end of January versus 555,000 contracts long at the end of December. 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 contracted to 79,000 contracts at the end of January versus 72,000 at the end of the previous month.

Figure 2: NYMEX Non-commercial net and short futures contracts: WTI January 2004 – January 2020

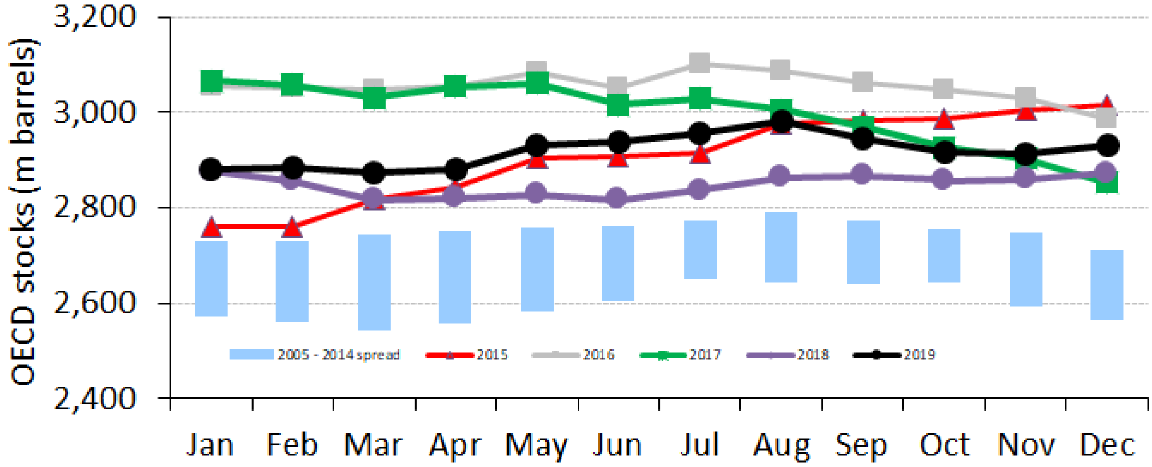


Source: Bloomberg LP/NYMEX/ICE (2020)

OECD stocks

OECD total product and crude inventories at the end of December (latest data point) were estimated by the IEA to be 2,931m barrels, up by 19m barrels versus the level reported for November. This compares to a 10-year average decrease for December of 34m barrels, implying that the market was oversupplied. Inventories built in 2019 overall by around 59m barrels (0.16m b/day).

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



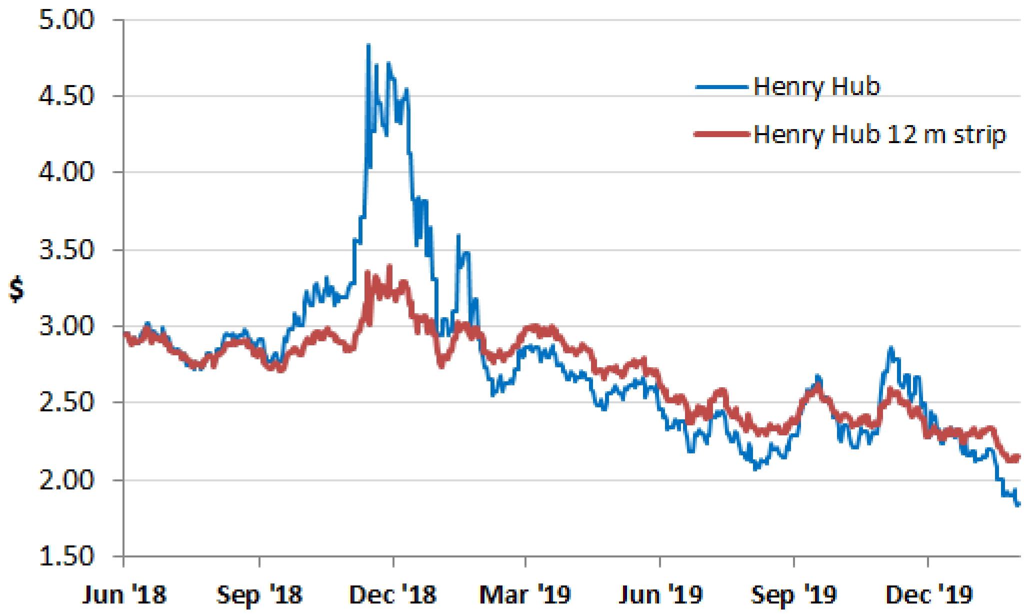
Source: IEA Oil Market Reports (January 2020 and older)

ii) Natural gas market

The US natural gas price (Henry Hub front month) opened January at $2.19/mcf (1,000 cubic feet), stayed reasonably flat for two weeks then fell sharply to end the month at $1.84/mcf. The spot gas price averaged $2.53/mcf so far in 2019, which compares to an average gas price of $3.07 in 2018 and $3.02 in 2017.

The 12-month gas strip price (a simple average of settlement prices for the next 12 months' futures prices) fell over the month, opening at $2.33/mcf and closing at $2.16 /mcf. The strip price averaged $2.60 in 2019, having averaged $2.90 in 2018 and $3.12 in 2017.

Figure 4: Henry Hub gas spot price and 12m strip ($/Mcf) 18 months July 31 2018 to January 31 2020



Source: Bloomberg LP

Factors which weakened the US gas price in January included:

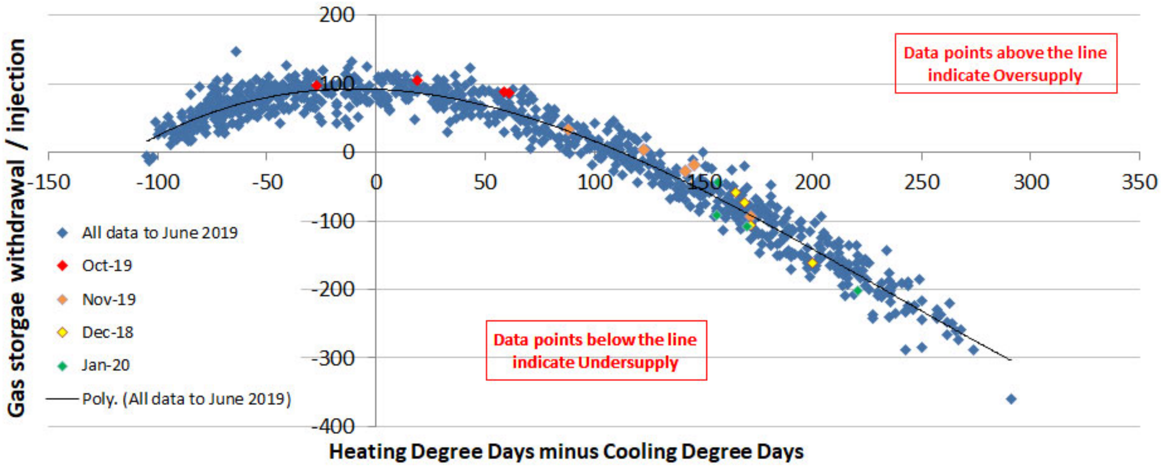
- **Increase in US onshore natural gas production**
  Onshore US natural gas production averaged 104.5 Bcf/day in November 2019 (the latest available data point), up by 0.9 Bcf/day versus the level reported for October and up by 8.7 Bcf/day since the start of the year. Rising associated gas supply from shale oil and a pickup of activity in the Marcellus basin are the key reasons for the increase in production this year.

- **Warm US winter dampening heating demand**
  The US has generally had a mild winter so far, dampening heating demand for gas. In aggregate, according to the American Gas Association, heating degree days have been 8.5 percent warmer than normal this winter (since October 1), and 3.9 percent warmer than last year. And every region has been warmer than normal.

Factors which strengthened the US gas price in January included:

- **Structurally undersupplied market**
  Adjusting for the impact of weather in January, the most recent movements of gas in storage suggest the market is, on average, operating at a deficit of around 2 Bcf/day (as indicated by the green dots on the graph below). Since September, the market has mainly been in surplus, so the swing to a deficit provides some respite.

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

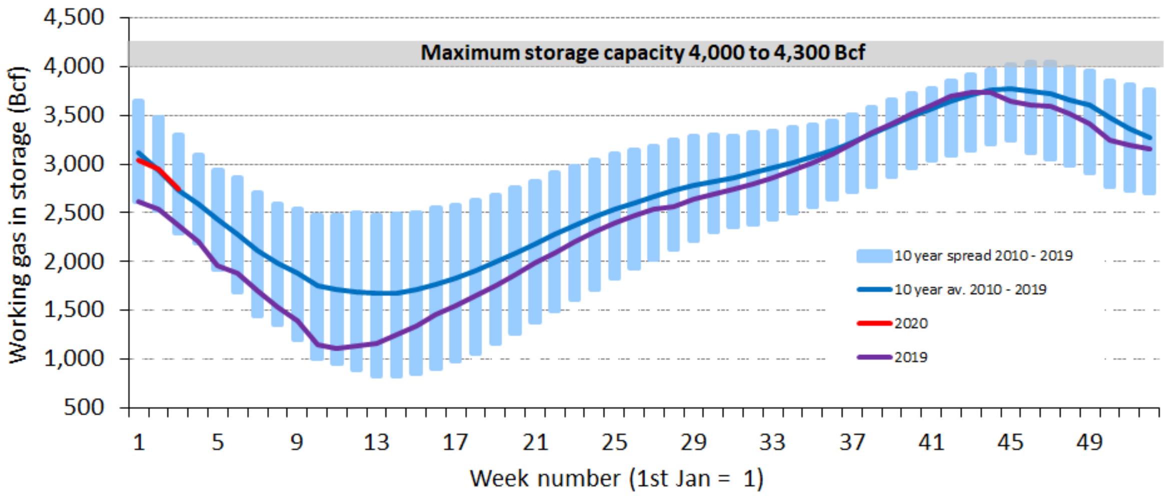


Source: Bloomberg LP; Guinness Asset Management

Natural gas inventories

Swings in the balance for US natural gas should, in theory, show up in movements in gas storage data. Natural gas inventories at the end of January were reported by the EIA to be 2.75 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 kept a cap on prices in 2019 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 (January 2020)

2. MANAGER'S COMMENTS

At the start of January we published an outlook piece for the year ahead. Here, we take the opportunity to provide updated comment on a number of the points made, in light of what we have seen so far this year:

- **We expect OPEC and their partners to remain disciplined in their pursuit of normalised oil inventories, and will seek to manage the Brent oil price at around $60/bl.** OPEC are striving to find a 'happy medium' for the oil market where their own economics are better satisfied, the world economy is kept stable and US oil supply grows in a controlled manner. Saudi are acting as the swing producer within OPEC, and will continue in this role in 2020.

  Reports for OPEC production suggest reasonable compliance with the quota cut that was enacted in January. Saudi will also be watching the supply situation in Libya closely, where exports have fallen sharply again thanks to political stand-off. However, OPEC's attention has of course moved on to the impact of the coronavirus – see comments that follow.

- **Global oil demand will depend on GDP growth, currently expected at around 1.2m b/day** if the IMF's GDP global forecast of 3.4% holds up. The non-OECD will deliver most of the growth in 2019, with China and India leading the way. We will see more than 3m electric vehicles sold this year but they will pose a negligible threat to oil demand growth.

  The major event in world markets in January was news of the spread of the novel coronavirus (2019-nCoV) in China and to other parts of the world. The spread of coronavirus has not been declared a pandemic, but appears to be the most serious new viral outbreak since SARS in 2003. The outbreak, which was first reported as coming from Wuhan in Hubei province, is causing major disruption to the Chinese economy, as authorities try to stop its spread. The impact on oil demand in China is likely to be pronounced, with consumption down as much as 20% (3m b/day), jet fuel being the biggest casualty. As cases of coronavirus multiply elsewhere in the world, we would expect oil demand to slow elsewhere, particularly since preventive measures will slow the volume of travel in most regions. The overall impact of the coronavirus on oil demand is unknowable. By comparison, SARS dented Chinese oil demand in 2003 by around 0.3 b/day. Given the expansion of the Chinese economy since then, and the coordinated prevention measures now occurring elsewhere, it would not be surprising to see 2020 global oil demand dented by 0.5m-1m b/day.

  The threat which the coronavirus poses to world oil demand has catalysed further discussion among OPEC members, with a view to a further production cut. However, with tanker export loadings already set for March, incremental cuts would only be effective from April at the earliest, potentially leaving an air pocket of inventory builds in China and elsewhere. At the time of writing, OPEC are recommending a further quota cut for OPEC+ of 0.6m b/day, though the group may wait until their scheduled meeting on 5/6 March to ratify any decision. Russia has been somewhat resistant to further, but we expect they will fall in with the OPEC group if the oil price slides further.

- **The US onshore shale system will grow again this year, albeit at a slower rate than 2019.** A lower average drilling rig count and the 'treadmill' challenge of overcoming high natural declines rates, will stunt US shale oil growth, which we expect at around 0.7m b/day (vs 1.2m b/day in 2019). We believe independent producers will remain more disciplined with their capital, with the market rewarding an appropriate balance of growth and free cashflow. Oil majors will remain more aggressively in 'shale oil growth' mode.

Initial indications are that US onshore oil production in 2020 will be consistent with the view described above, with growth slowing by around 0.5m b/day versus last year. The US oil directed drilling rig count at the end of January was reported at 675 rigs, down slightly from the start of the year, but well down on the late 2018 peak of 888 rigs. We would also stress the importance of natural decline rates on the prospects for 2020: by our estimation, the US will need to grow production by an additional 0.3m b/day versus 2019 simply to overcome the effect of additional declines.

- **Non-OPEC (ex US onshore) supply will grow by around 1m b/day in 2020 but major project additions then dry up.** Additions in 2020 come mainly from the start-up of the giant Johann Svedrup field offshore Norway, plus production coming through in sub-salt fields offshore Brazil. We see no repeat of this in 2021/22, even if oil prices rise from here, as upstream capex cuts from 2015-19 take effect.

  The Johann Svedrup field, which is expected to add 0.4m b/day of non-OPEC growth in 2020, has started up successfully and a little ahead of schedule. Brazilian production in December 2019 was reported at an all-time high of 3.1m b/day, up by 0.4m year-on-year. As expected, sub-salt field production has been particularly strong, up 0.6m b/day.

- **OECD oil inventories likely to be similar to end-2019** but the path will be bumpy. Looking further ahead, we believe that continued oil demand growth, and a softening of non-OPEC supply growth, will allow OPEC greater control of the market.

  As things stand, achieving flat oil inventories over the year looks now to rely on OPEC cutting production to counter the negative impact which the coronavirus will likely have on demand growth.

- **Global gas demand will grow handsomely again in 2020** led by strong Asian GDP growth and a shift in the region from coal to gas consumption by power utilities, though international gas prices will remain muted as oversupply persists.

  International gas prices have started the year particularly weakly, with European prices dropping close to $3/mcf and Asian prices close to $4/mcf. In addition to demand concerns arising from the Coronavirus, prices have been pressured by another mild winter across the Northern hemisphere, which has dampened the use of gas in heating.

- **Free cash flow for energy companies remains a priority in 2020.** Shareholder pressure for energy companies to live within cash flow, cover dividends and buyback shares should keep free cash flow in sharp focus. We expect improvements here even in a static oil price environment.

  Results from the large and mid-cap integrateds have been mixed so far in this reporting season, with earnings in some cases held back by the weak refining and chemicals environment in the fourth quarter of 2019. However, particularly in Europe, there has been a consistent message of dividend raises (e.g. BP; Total; Equinor; OMV) which we believe demonstrates confidence in the high level of dividend cover available.

- **Energy equity valuations remain at depressed levels.** On a relative price-to-book (P/B) basis (versus the S&P500), the valuation of energy equities sit at a 50 year low, at 0.5x, just below level that it was at in February 2016 when Brent oil was $29/bl. We believe that improving ROCE (we forecast 7% for our portfolio in 2019 assuming $60 Brent prices, up from 1% in 2016) should drive a higher P/B ratio.

  At the start of the year, we estimated that the oil price implied in the valuation of energy equity sector was around $50/bl. The sector fell by around 10% in January, reducing the long-term implied oil price to around $47/bl. At a long-term oil price of $60/bl, which we consider to be OPEC's 'baseline', we believe there is now around 45% valuation upside.

1) PERFORMANCE Guinness Global Energy Fund

The main index of oil and gas equities, the MSCI World Energy Index (net return), fell by 9.1% in January, while the MSCI World Index (net return) fell by 0.6%. The Fund was down by 11.1% (class E) in the month, underperforming the MSCI World Energy index by 2.0% (all in US dollar terms).

Within the Fund, January's strongest performers were Enquest, BP, Occidental, Enbridge and while the weakest performers were Uvintiv, Oasis, Noble, Tullow and Schlumberger.

Performance (in USD) **31/01/2020**

Annualised

% returns	1 month	3 months	6 months	1 year	2 years	3 years	Fund launch
Guinness Global Energy Fund (Class E)	-11.1%	-4.7%	-9.7%	-13.3%	-24.8%	-20.7%	-67.3%
MSCI World Energy NR Index	-9.1%	-3.0%	-7.5%	-8.2%	-17.1%	-7.7%	-11.6%
MSCI World Small Cap Energy Index	-16.4%	-5.5%	-18.1%	-29.1%	-44.3%	-49.5%	-67.1%
50/50 Mix of World Enegy and Small Cap Index	-12.8%	-4.2%	-12.8%	-18.7%	-30.7%	-28.6%	-39.3%
Outperformance/Underperformance	1.7%	-0.5%	3.0%	5.4%	5.8%	7.9%	-27.9%

Calendar year

% returns	YTD	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Guinness Global Energy Fund (Class E)	-11.1%	9.8%	-19.7%	-1.3%	27.9%	-27.6%	-19.1%	24.4%	3.0%	-13.7%	15.3%	61.8%	-67.2%
MSCI World Energy NR Index	-9.1%	11.4%	-15.8%	5.0%	26.6%	-22.8%	-11.6%	18.1%	1.9%	0.2%	11.9%	26.2%	-38.1%
MSCI World Small Cap Energy Index	-16.4%	-2.3%	-31.3%	-12.0%	37.0%	-37.3%	-33.1%	16.4%	1.4%	-9.2%	34.8%	77.5%	-55.5%
50/50 Mix of World Enegy and Small Cap Index	-12.8%	4.6%	-23.6%	-3.5%	31.8%	-30.1%	-22.3%	17.3%	1.6%	-4.5%	23.3%	51.9%	-46.8%
Outperformance/Underperformance	1.7%	5.2%	3.9%	2.2%	-3.9%	2.5%	3.3%	7.1%	1.4%	-9.2%	-8.0%	9.9%	-20.4%

Source: Guinness Asset Management and Bloomberg, 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 **January 31 2020**.

Asset allocation as %NAV	Current	*Change*	Last year end	Previous year ends							
	Jan-20		Dec-19	Dec-18	Dec-17	Dec-16	Dec-15	Dec-14	Dec-13	Dec-12
Oil & Gas	**99.6%**	***1.3%***	**98.3%**	**96.7%**	**98.4%**	**96.7%**	**95.1%**	**93.7%**	**93.6%**	**98.6%**
Integrated	52.8%	*1.6%*	51.1%	46.4%	42.9%	46.4%	41.5%	37.3%	38.4%	39.1%
Exploration & Production	28.7%	*-0.9%*	29.6%	35.8%	36.9%	35.8%	36.5%	36.2%	35.2%	41.6%
Drilling	0.1%	*0.0%*	0.1%	2.2%	1.9%	2.2%	1.5%	3.3%	7.0%	7.4%
Equipment & Services	9.4%	*-0.1%*	9.6%	8.6%	9.5%	8.6%	11.4%	13.4%	9.8%	7.1%
Storage & Transportation	4.7%	*0.7%*	4.0%	0.0%	3.5%	0.0%	0.0%	0.0%	0.0%	0.0%
Refining & Marketing	3.9%	*0.1%*	3.8%	3.7%	3.7%	3.7%	4.2%	3.5%	3.1%	3.4%
Solar	0.9%	*0.2%*	0.7%	0.9%	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%	0.0%
Construction & Engineering	0.0%	*0.0%*	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.2%	0.6%
Cash	-0.5%	*-1.5%*	1.1%	2.4%	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 January 31 2020 was on a price to earnings ratio (P/E) for 2019 of 11.8x versus the S&P 500 Index at 20.5x as set out in the following table:

	2018	2019	2020
Fund P/E	9.9	11.8	10.3
S&P 500 P/E	21.3	20.5	18.5
Premium (+) / Discount (-)	*-53%*	*-43%*	*-44%*
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.53%) 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 January 31 2020 the median P/E ratio of this group was 11.6x 2019 earnings. We also have two Canadian integrated holdings, Suncor and Imperial Oil. Both companies have significant exposure to oil sands in addition to downstream assets.

Our exploration and production holdings (c.29%) 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 (EOG, 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 Pharos Energy). Gazprom is the Russian national oil and gas company which produces approximately a quarter of the European Union gas demand and trades on 4.0x 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. Pharos Energy 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 10% 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 December 31 2019 (for compliance reasons disclosed one month in arrears)

Guinness Global Energy Fund (31 December 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	4.0%	228,531	-1%	15%	15%	15%	32%	15.0x	18.6x	17.7x	5.9x	6.8x	6.3x
Royal Dutch Shell PLC	3.9%	233,324	-7%	6%	6%	29%	22%	11.4x	13.1x	11.2x	5.4x	5.5x	5.2x
BP PLC	3.9%	128,044	-7%	5%	5%	20%	35%	10.5x	12.8x	11.6x	5.0x	5.1x	4.8x
Total SA	4.0%	144,713	0%	9%	9%	24%	39%	11.0x	12.3x	10.7x	5.5x	5.4x	4.9x
ENI SpA	4.0%	56,838	-4%	5%	5%	12%	17%	n/a	n/a	n/a	n/a	n/a	n/a
Equinor ASA	4.1%	67,448	4%	0%	0%	24%	44%	n/a	n/a	n/a	n/a	n/a	n/a
Repsol SA	3.9%	24,710	3%	4%	4%	32%	13%	9.1x	9.2x	7.5x	4.6x	4.7x	4.2x
OMV AG	3.9%	18,365	15%	33%	33%	74%	151%	n/a	n/a	n/a	n/a	n/a	n/a
	31.6%								12.77	11.21			
Integrated / Oil & Gas E&P - Canada													
Suncor Energy Inc	4.0%	50,485	7%	22%	22%	11%	22%	15.2x	13.0x	14.1x	6.2x	6.1x	6.1x
Canadian Natural Resources Ltd	4.1%	37,705	23%	39%	39%	13%	24%	15.0x	12.6x	14.2x	6.8x	6.4x	6.3x
Imperial Oil Ltd	4.1%	19,774	-3%	7%	7%	-19%	-33%	12.5x	13.0x	15.5x	6.6x	7.8x	7.5x
	12.2%												
Integrated Oil & Gas - Emerging market													
PetroChina Co Ltd	4.0%	147,164	-7%	-16%	-16%	-26%	-48%	11.2x	13.0x	11.8x	4.5x	4.9x	4.8x
Gazprom PJSC	4.0%	99,618	20%	99%	99%	97%	136%	4.3x	4.5x	5.1x	3.6x	4.1x	4.1x
	8.0%												
Oil & Gas E&P													
Occidental Petroleum Corp	3.5%	37,761	-15%	-28%	-28%	-32%	-35%	8.3x	23.9x	48.0x	9.9x	10.2x	7.9x
ConocoPhillips	4.0%	71,663	8%	7%	7%	38%	8%	14.6x	17.2x	19.5x	5.0x	5.0x	6.0x
EOG Resources Inc	3.1%	48,804	-9%	-3%	-3%	-15%	-5%	14.6x	17.5x	16.7x	6.4x	6.8x	6.3x
Devon Energy Corp	3.2%	9,887	-8%	17%	17%	-41%	-55%	17.2x	20.2x	16.6x	4.3x	5.0x	5.1x
Noble Energy Inc	3.3%	11,594	12%	35%	35%	-31%	-43%	25.7x	n/a	134.3x	6.7x	8.6x	6.6x
EnCana Corp	3.1%	6,080	-8%	-18%	-18%	-59%	-64%	7.0x	8.5x	8.3x	6.6x	4.2x	3.9x
Oasis Petroleum Inc	1.3%	1,019	-43%	-41%	-41%	-78%	-80%	11.6x	n/a	n/a	4.1x	4.1x	4.6x
	21.6%												
International E&Ps													
CNOOC Ltd	4.2%	74,395	0%	14%	14%	55%	58%	9.5x	9.1x	8.9x	3.3x	3.6x	3.4x
Tullow Oil PLC	0.6%	1,102	-68%	-62%	-62%	-74%	-84%	7.6x	5.5x	10.6x	2.7x	3.0x	3.7x
Pharos Energy PLC	0.5%	280	-22%	-13%	-13%	-59%	-81%	21.0x	n/a	27.7x	3.1x	2.5x	2.1x
	5.4%												
Midstream													
Enbridge Inc	4.0%	80,066	14%	36%	36%	12%	-1%	19.7x	19.2x	19.5x	14.5x	13.7x	13.3x
	4.0%												
Equipment & Services													
Halliburton Co	3.9%	21,449	10%	-5%	-5%	-52%	-31%	13.2x	20.2x	18.3x	7.3x	8.5x	8.2x
Helix Energy Solutions Group Inc	1.7%	1,424	12%	78%	78%	9%	-56%	43.8x	27.8x	23.4x	11.3x	9.9x	8.3x
Schlumberger Ltd	4.0%	55,701	4%	18%	18%	-46%	-44%	24.7x	27.5x	23.3x	10.4x	10.7x	10.3x
	9.5%												
Oil & Gas Refining & Marketing													
Valero Energy Corp	3.8%	38,794	12%	30%	30%	54%	128%	15.2x	18.7x	9.5x	8.1x	8.9x	6.1x
	3.8%												
Research Portfolio													
Cluff Natural Resources PLC	0.3%	30	-3%	-30%	-30%	-32%	-65%	n/a	n/a	n/a	n/a	n/a	n/a
EnQuest PLC	0.8%	491	14%	2%	2%	-36%	-34%	5.7x	3.2x	4.1x	4.0x	3.2x	3.5x
JKX Oil & Gas PLC	0.1%	55	-34%	-35%	-35%	-13%	74%	16.2x	n/a	n/a	2.2x	n/a	n/a
Reabold Resources PLC	0.5%	66	-29%	6%	6%	7%	-80%	n/a	n/a	n/a	n/a	n/a	n/a
Shandong Molong Petroleum Machinery Co Ltd	0.1%	334	-24%	-23%	-23%	-63%	-68%	n/a	n/a	n/a	n/a	n/a	n/a
Sunpower Corp	0.7%	1,317	-27%	57%	57%	18%	-70%	n/a	n/a	49.7x	24.5x	19.6x	14.0x
Unit Corp	0.1%	39	-92%	-95%	-95%	-97%	-98%	0.7x	n/a	n/a	2.9x	3.9x	3.6x
Diversified Gas & Oil Company	0.5%	908	6%	4%	4%	n/a	n/a	9.2x	7.8x	8.3x	10.6x	5.9x	6.1x
	2.9%												
Cash	**1.1%**												

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*	*64.9*	*67.0*
OPEC NGLs	*5.2*	*5.4*	*5.5*	*5.5*	*5.5*	*5.5*
Non-OPEC supply plus OPEC NGLs	**65.0**	**64.6**	**65.6**	**68.4**	**70.4**	**72.5**
Call on OPEC (crude oil)	**30.3**	**31.8**	**32.6**	**30.9**	**29.9**	**29.0**
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	28.4

Source: Bloomberg; IEA; Guinness Asset Management

Global oil demand in 2019 was 13m 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 1.2m b/day in 2020, which would take oil demand to a new high of 101.5m 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.

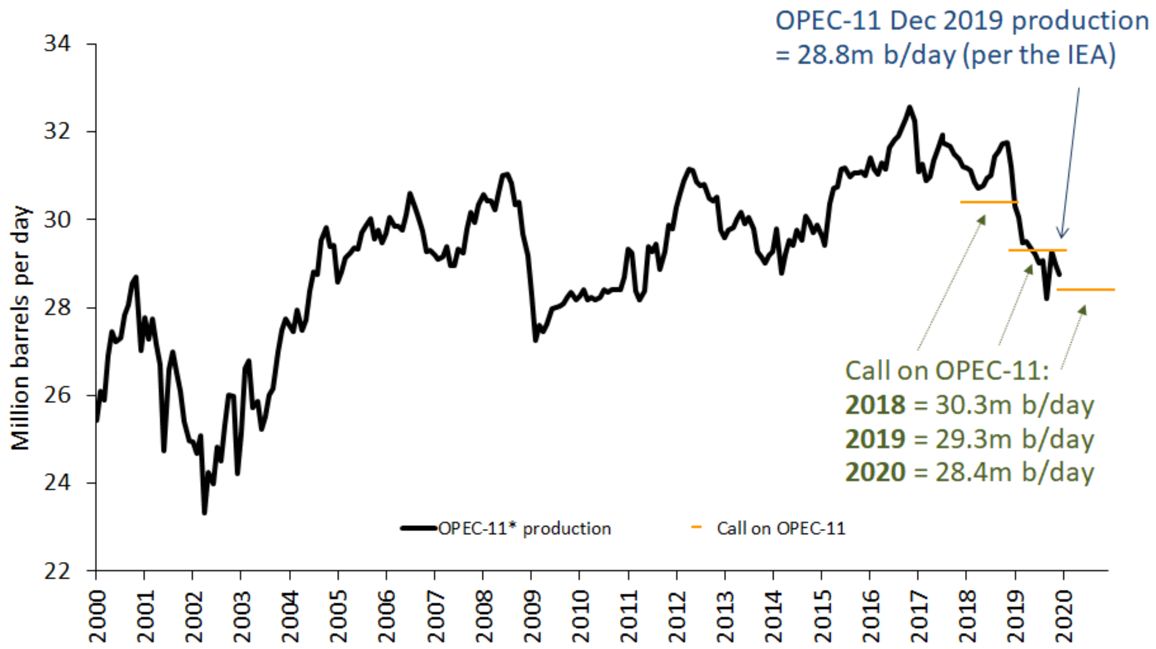
('000 b/day)	30-Nov-14	31-Dec-16	31-Jan-20	Current vs Nov 2014 (OPEC hold mkt share)	Current vs Dec 2016 (OPEC cut production)
Saudi	9,650	10,480	**9,700**	50	-780
Iran	2,780	3,730	**1,990**	-790	-1,740
Iraq	3,370	4,630	**4,580**	1,210	-50
UAE	2,800	3,070	**3,010**	210	-60
Kuwait	2,790	2,860	**2,670**	-120	-190
Nigeria	1,970	1,500	**1,830**	-140	330
Venezuela	2,350	2,080	**840**	-1,510	-1,240
Angola	1,640	1,670	**1,320**	-320	-350
Libya	580	630	**790**	210	160
Algeria	1,100	1,110	**1,010**	-90	-100
Ecuador	561	550	**530**	-31	-20
OPEC-11	**29,591**	**32,310**	**28,270**	**-1,321**	**-4,040**

Source: Bloomberg; Guinness Asset Management

The last two years 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, those quota cuts were extended to March 2020.

At the conclusion of their latest meeting in December 2019, OPEC+'s headline announcement was an agreement to deepen production cuts (still extending to March 2020) from 1.2m b/day to 1.7m b/day. Despite two days of negotiations to reach this agreement, no formal country quotas were announced but we estimate that OPEC's share of the production cuts expanded from 0.8m b/day to 1.2m b/day, whilst non-OPEC 'partners' expanded their cuts from just under 0.4m b/day to 0.5m b/day. In addition to their reduced formal production quota, Saudi committed until March 2020 to a further 0.4m b/day of voluntary cuts, taking the total OPEC+ cut since December 2018 to 2.1m b/day. However, Saudi stated that the voluntary deeper cuts were contingent on 100% compliance from other OPEC+ members.

Figure 7: OPEC-11 apparent production vs call on OPEC 2000 – 2020



Source: IEA Oil Market Report (January 2020 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:

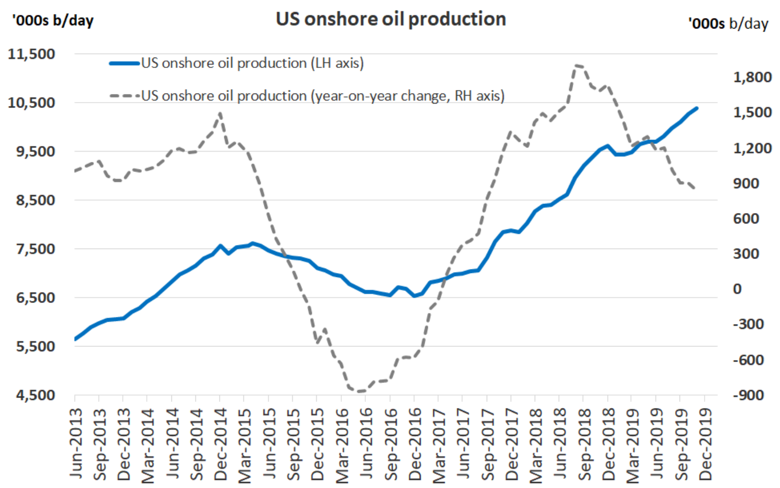
1. Saudi is interested in the average price of oil that they get, they have a longer investment horizon than most other market participants
2. Saudi wants to maintain a balance between global oil supply and demand to maintain a price that is acceptable to both producers and consumers

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 1.8% p.a. from 2008-2019.

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 8m 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.

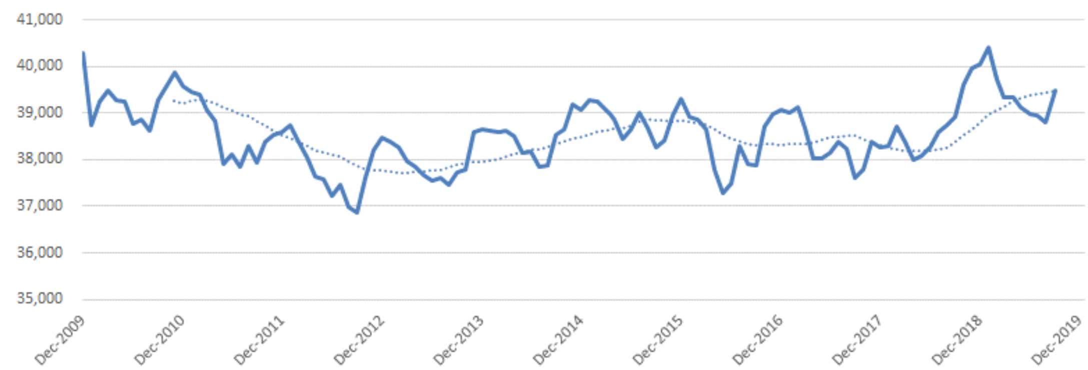


Source: EIA; Guinness Asset Management

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 initially peaked in 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. 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. During 2019, we started to see increased pressure on US E&P companies to improve their capital discipline and to cut their reinvestment rates, and this evidenced by higher costs of capital being charged to the US E&P companies. Whether this greater capital discipline affects production growth will not become clear until later in 2020.

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 was 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, though 2019 saw the reverse.

The IEA's global demand estimate for 2020 comprises an increase in non-OECD demand of 0.9m b/day and an increase in OECD demand of 0.3m 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	25.2	26.2	27.0	27.9	28.7	0.7	0.7	1.3	1.1	1.0	0.8	0.9	0.8
Middle East	7.9	8.4	8.5	8.4	8.4	8.3	8.4	8.3	0.1	0.5	0.1	-0.1	0.0	-0.1	0.1	-0.1
Latin America	6.7	6.8	6.7	6.5	6.5	6.4	6.4	6.4	0.3	0.1	-0.1	-0.2	0.0	-0.1	0.0	0.0
FSU	4.7	4.66	4.6	4.4	4.6	4.7	4.8	4.9	0.1	0.0	-0.1	-0.1	0.2	0.1	0.1	0.1
Africa	3.9	3.8	4.2	4.2	4.2	4.2	4.3	4.4	0.1	-0.1	0.4	0.0	0.0	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**	**49.3**	**50.6**	**51.4**	**52.5**	**53.4**	**1.3**	**1.2**	**1.6**	**0.7**	**1.2**	**0.8**	**1.2**	**0.9**

Source: IEA Oil Market Report (January 2020)

Asia has settled down into a steady pattern of growth since 2010, and accounts for much of the expected growth in 2020. 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 2020 is forecast to be up by 0.3m b/day. In the US, the sharp fall in gasoline prices since 2014 has stimulated a reversal in improving fuel efficiency, as drivers switch back to purchasing larger vehicles, and a rise in total vehicle miles travelled. 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 2019/20 is capping OECD demand growth at a low level.

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 1.2m in 2019, up from 1.8m in 2018. We expect to see EV sales accelerate in 2020 to around 2.8m, or 3% of total global sales. Even applying an aggressive growth rate to EV sales, we see EVs comprising only around 0.9% of the global car fleet by the end of

2020. Looking further ahead, we expect the penetration of EVs to accelerate, causing global gasoline demand to peak at some point in the middle 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 early 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	2020
WTI	30	33	38	49	66	75	82	104	68	84	99	94	98	93	49	45	51	65	57	57
Brent	30	32	35	46	64	75	82	103	67	84	115	112	108	99	52	45	54	72	60	60
Brent/WTI (12m MAV)	**30**	**33**	**37**	**48**	**65**	**75**	**82**	**104**	**68**	**84**	**107**	**103**	**103**	**96**	**51**	**45**	**53**	**68**	**59**	**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%	0%
Brent/WTI (5yr MAV)	30	25	32	37	42	51	61	75	79	82	89	93	93	99	92	80	69	63	55	57

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.

Figure 11: US natural gas demand

Bcf/day	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019E	2020E
US natural gas demand:													
Residential/commercial	22.0	21.6	21.6	21.6	19.2	22.4	23.4	21.4	20.5	20.9	23.4	23.9	23.3
Power generation	18.2	18.8	20.2	20.8	24.9	22.3	22.3	26.5	27.3	25.3	29.0	30.7	30.8
Industrial	18.2	16.9	18.5	19.0	19.7	20.3	20.9	20.6	21.1	21.6	23.0	23.0	23.2
Pipeline exports (Mexico)	1.0	0.9	0.9	1.4	1.8	1.9	1.9	2.7	3.8	4.0	4.6	5.1	5.7
LNG exports	-	-	-	-	-	-	-	0.1	1.0	2.6	3.4	5.6	8.6
Pipeline/plant/other	5.3	5.5	5.6	5.8	6.1	6.7	6.3	6.5	6.4	6.5	7.1	7.7	8.0
Total demand	**64.7**	**63.7**	**66.8**	**68.6**	**71.7**	**73.6**	**74.8**	**77.8**	**80.1**	**80.9**	**90.5**	**96.0**	**99.6**
Demand growth	**- 0.7**	**- 1.0**	**3.1**	**1.8**	**3.1**	**1.9**	**1.2**	**3.0**	**2.3**	**0.8**	**9.6**	**5.5**	**3.6**
Demand growth		***-2%***	***5%***	***3%***	***5%***	***3%***	***2%***	***4%***	***3%***	***1%***	***12%***	***6%***	***4%***

Source: Guinness estimates, Simmons, GS (January 2020)

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.

Total gas demand in 2019 (including Mexican and LNG exports) was around 96 Bcf/day, up by 5.5 Bcf/day (6%) versus 2018 and 15 Bcf/day (19%) higher than the 5 year average. The biggest contributors to the growth in demand in 2019 were power generation (hot summer and start-up of numerous gas plants increasing gas' share over coal) and LNG exports (opening of new export terminals).

We expect US demand in 2020, assuming prices remain around $2.50/mcf, to exhibit further strong growth of around 3.6 Bcf/day. Normalised weather would keep a cap on power generation demand, but there should be another surge in LNG exports (c.3 Bcf/day in 2019), as a wave of new export terminals come into service.

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.

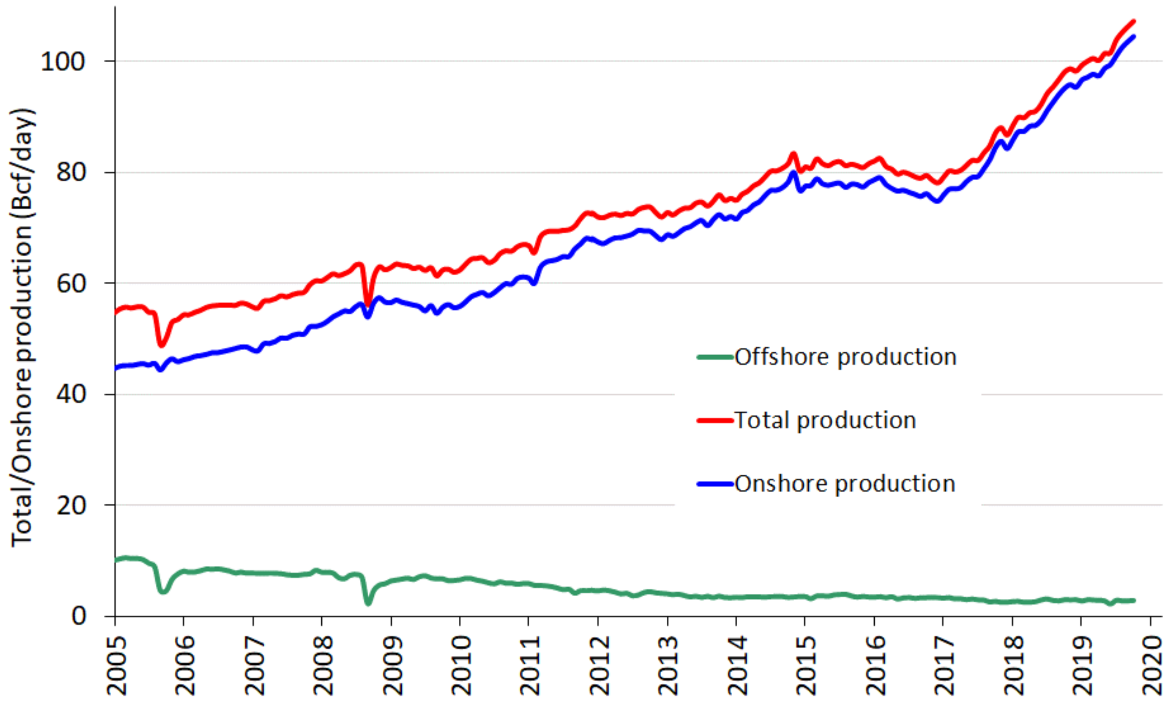
The supply side fundamentals for natural gas in the US are driven by 3 main moving parts: onshore and offshore domestic production, pipeline imports of gas from Canada and net LNG imports. Of these, onshore supply is the biggest component, making up over 85% of total supply.

Bcf/day	2008	*2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019E	2020E
US natural gas supply:													
US (onshore & offshore)	55.1	56.5	58.4	62.7	65.7	66.3	70.9	74.2	73.4	73.6	84.0	91.9	95.6
Net imports (Canada)	8.3	7.1	7.0	5.8	5.4	5.0	4.9	4.9	5.5	5.8	5.4	4.9	4.8
LNG imports & other	1.2	1.4	1.4	1.0	0.8	0.6	0.5	0.5	0.4	0.3	0.1	0.1	0.1
Total supply	**64.6**	**65.0**	**66.8**	**69.5**	**71.9**	**71.9**	**76.3**	**79.6**	**79.3**	**79.7**	**89.5**	**96.9**	**100.5**
Supply growth		**0.4**	**1.8**	**2.7**	**2.4**	**-**	**4.4**	**3.3**	**- 0.3**	**0.4**	**9.8**	**7.4**	**3.6**
Demand growth		***1%***	***3%***	***4%***	***3%***	***0%***	***6%***	***4%***	***0%***	***1%***	***12%***	***8%***	***4%***
(Supply)/demand balance	**0.1**	**- 1.3**	**-**	**- 0.9**	**- 0.2**	**1.7**	**- 1.5**	**- 1.8**	**0.8**	**1.2**	**1.0**	**- 0.9**	**- 0.9**

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 January 2020. 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 (November 2019) at 104.5 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 (Nov 2019 published in Feb 2020)

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.

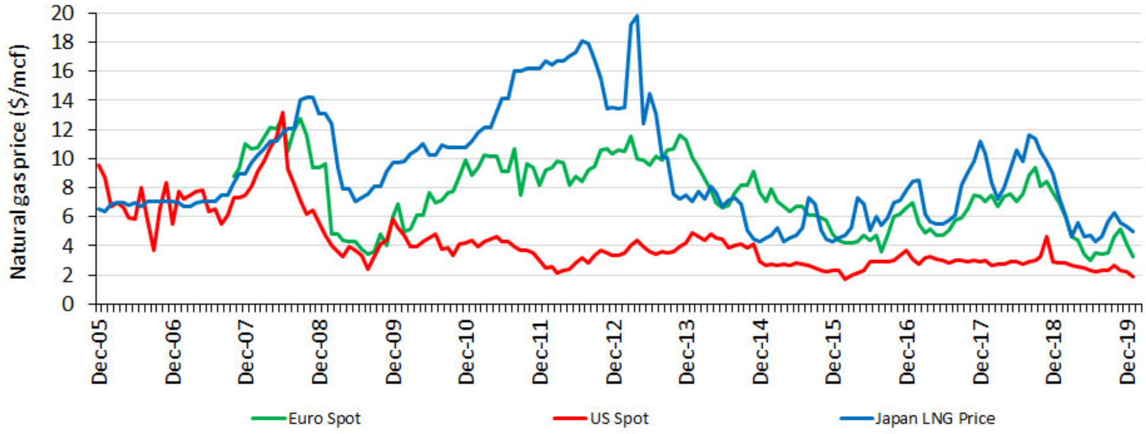
Associated gas production declined in 2016 with the fall of shale oil production, but with US oil supply now growing well again, so associated gas production has picked up. Generally, we expect to see rates of around 2-3 Bcf/day of associated gas per 1m b/day of oil production growth.

The Marcellus/Utica region, which includes the largest producing gas field in the US and the surrounding region, reached production of around 32 Bcf/day in 2020, but growth likely slows in 2020 with prices so low.

Overall, if the price remains in the $2.50-$3/mcf range, we expect another strong rise in onshore gas supply in 2020, up by around 3-4 Bcf/day versus 2019.

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.



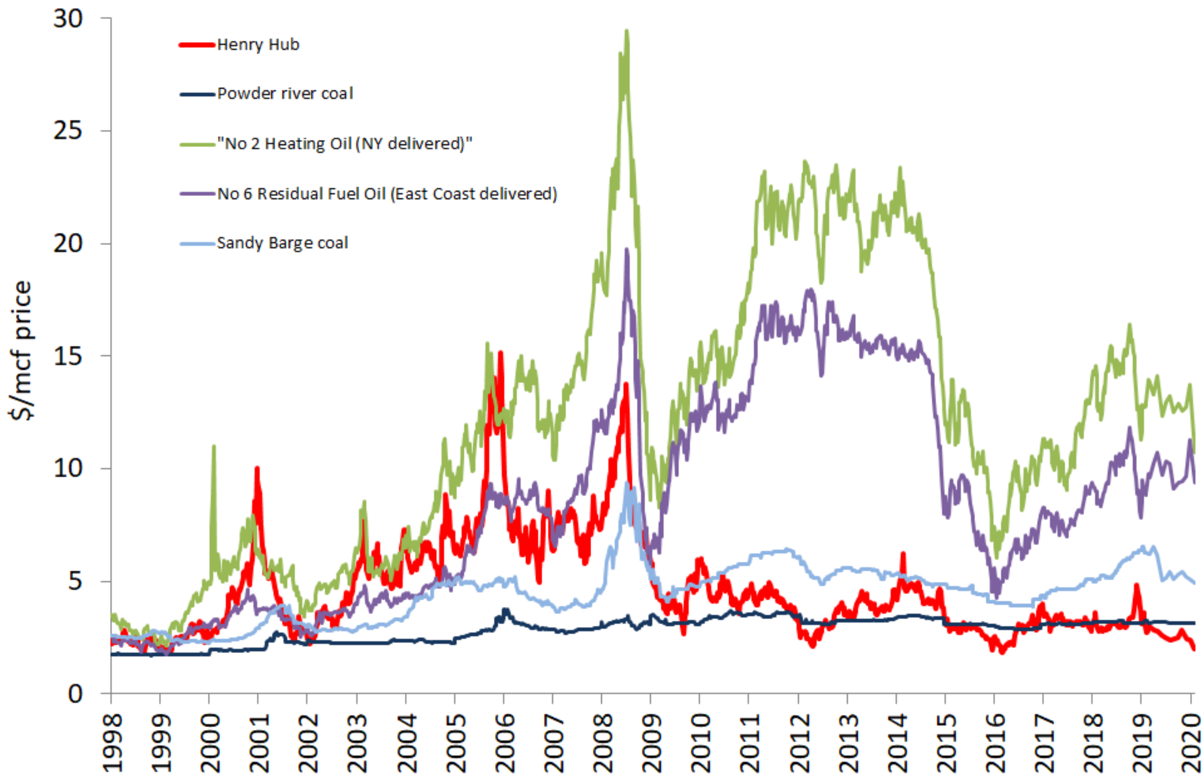
Source: Bloomberg (Jan 2020)

Relationship with oil and coal

The oil/gas price ratio ($ per bbl WTI/$ per mcf Henry Hub) of around 28x at the end of January 2020 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 (Jan 2020)

Conclusions about US natural gas

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 2019 natural gas prices (at $2.53) were around 40% 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.

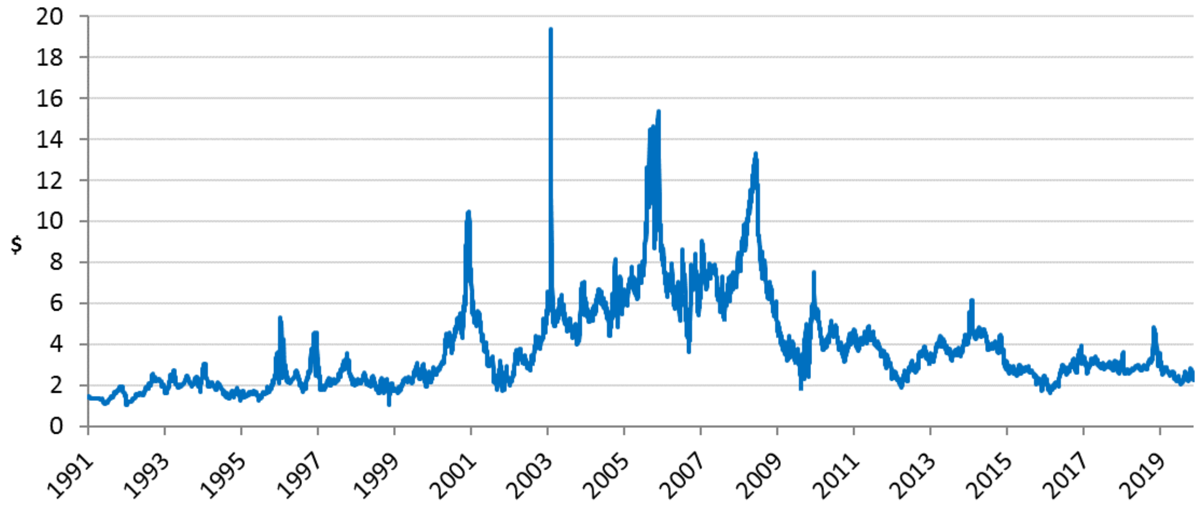
Continued expectations of a supply crunch by the end of the decade, coupled with increased speculative activity in oil markets, contributed to the oil price surging past $90 in the final months of 2007 and as high as $147 by the middle of 2008. This spike was brought to an abrupt end by the collapse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

IMPORTANT INFORMATION AND RISK FACTORS

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

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

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

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

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

- the Manager: Link Fund Manager Solutions (Ireland) Ltd, 2 Grand Canal Square, Grand Canal Harbour, Dublin 2, Ireland; or,
- the Promoter and Investment Manager: Guinness Asset Management Ltd, 18 Smith Square, London, SW1P 3HZ

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

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

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

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

Telephone calls will be recorded and monitored.