THE GUINNESS GLOBAL ENERGY REPORT

Developments and trends for investors in the global energy sector | May 2021

GUINNESS GLOBAL ENERGY FUND

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 co-managers Will Riley, Jonathan Waghorn and Tim Guinness, supported by Jamie Melrose (analyst). The investment philosophy, methodology and style which characterise the Guinness approach have been applied to the management of energy equity portfolios since 1998.

Important information about this report

This report is primarily designed to inform you about recent developments in the energy markets invested in by the Guinness Global Energy Fund. It also provides information about the Fund's portfolio, including recent activity and performance. This document is provided for information only and all the information contained in it is believed to be reliable but may be inaccurate or incomplete; any opinions stated are honestly held at the time of writing, but are not guaranteed. The contents of the document should not therefore be relied upon. It is not an invitation to make an investment nor does it constitute an offer for sale.

HIGHLIGHTS FOR APRIL

OIL

WTI/Brent up on stronger demand outlook; risks remain

Brent and WTI both up in April. WTI closed the month up $4/bl at $63.5/bl, whilst Brent also rose $4/bl to $67/bl. Global oil demand for 2021 was upgraded by 0.2m b/day in the month with non-OPEC supply reduced by 0.2m b/day, increasing the call on OPEC by 0.4m b/day. Concerns continue around the level of unofficial oil exports leaving Iran and the potential effects of COVID on emerging market demand.

NATURAL GAS

US gas price up; European and Asian gas prices up

Henry Hub price rose over the month, moving from $2.61/mcf to $2.94/mcf. The US market tightened in April but remained oversupplied by around 0.5 Bcf/day. European and Asian gas prices rose, both reaching around $8/mcf, reflecting lower inventories and stronger demand.

EQUITIES

Energy underperforms the broad market in April

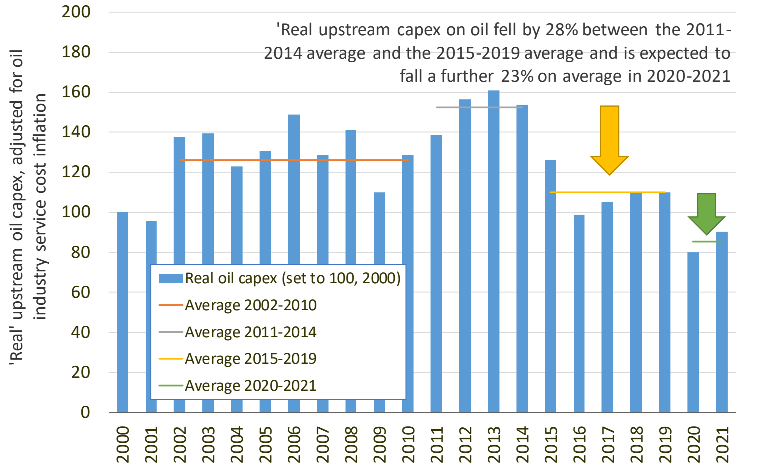
The MSCI World Energy Index (net return) rose by 0.4% in April, underperforming the MSCI World Index (net return) which rose by 4.7% over the month (all in US dollar terms).

CHART OF THE MONTH

Upstream oil and gas investment suffers under COVID

As discussed in our manager's comments, COVID contributed to oil and gas industry investment falling by 28% in 2020, to the lowest level since 2005. On our analysis, investment into oil projects in 2020/2021 (adjusted for the effects of industry cost inflation) is likely to fall by 23% versus the levels seen in 2015-2019 and by 44% versus the peak levels in 2011-2014, taking 'real investment' into oil field projects back to the levels last seen in 2000/2001, at the start of the last super-cycle.

Oil project capital investment (adjusted for oil industry inflation)



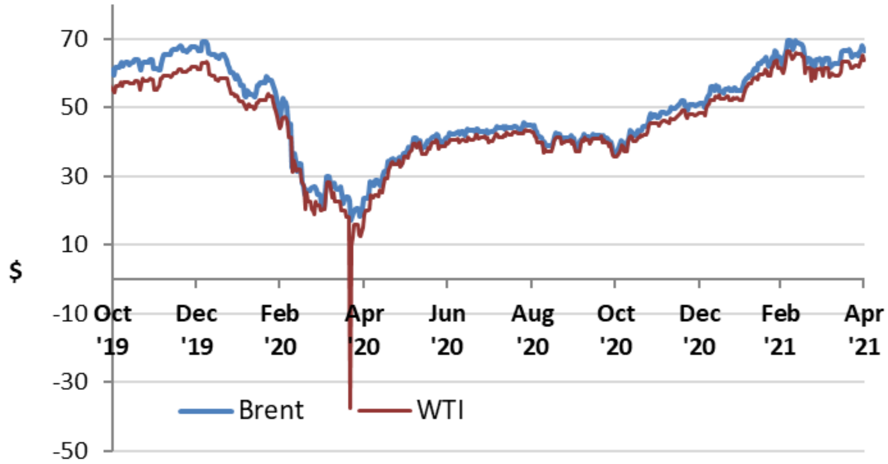
Source: IHS Markit, JP Morgan, Wood Mackenzie, Guinness Asset Management

Contents

1. APRIL IN REVIEW

i) Oil market

Figure 1: Oil price (WTI and Brent $/barrel): Oct 2019 to April 2021



Source: Bloomberg LP

The West Texas Intermediate (WTI) oil price started April at $59.2/bl and traded broadly flat for the first half of the month before steadily increasing to end the month close to its highs at $63.5/bl. WTI has averaged $58.8/bl so far in 2021, having averaged $40/bl in 2020, $58/bl in 2019 and $65/bl in 2018.

Brent oil traded in a similar shape, opening at $63/bl and closing the month close to its highs at $67.3/bl. Brent has averaged $61.7/bl so far in 2021, having averaged $42/bl in 2020, $64/bl in 2019 and $72/bl in 2018. The gap between the WTI and Brent benchmark oil prices expanded slightly over the month, ending April at nearly $4/bl, versus nearly $3/bl on average in 2020.

Factors which strengthened WTI and Brent oil prices in April:

- **Tightening supply/demand outlook**
  In its April Oil Market Report, the IEA increased its outlook for 2021 oil demand by 0.2m b/day and reduced its outlook for non-OPEC supply by 0.2m b/day for 2021, thus increasing the call on OPEC from 26.7m b/day to 27.1m b/d for the year. While the outlook for demand in 2021 remains volatile, as a result of COVID, the supply/demand balance improved over the month.

- **Limited growth from US shale oil; cold weather impact in February now reported**
  Latest data published by the EIA implies that US shale oil production continued to fall with a very sharp decline being registered in February as a result of exceptionally cold weather conditions in that month.

While the February impact was only short term, the US rig count is still around a quarter below the level needed to stabilise output from the US onshore system, with shale companies' presentations and communications still indicating strong focus on free cash flow generation in 2021.

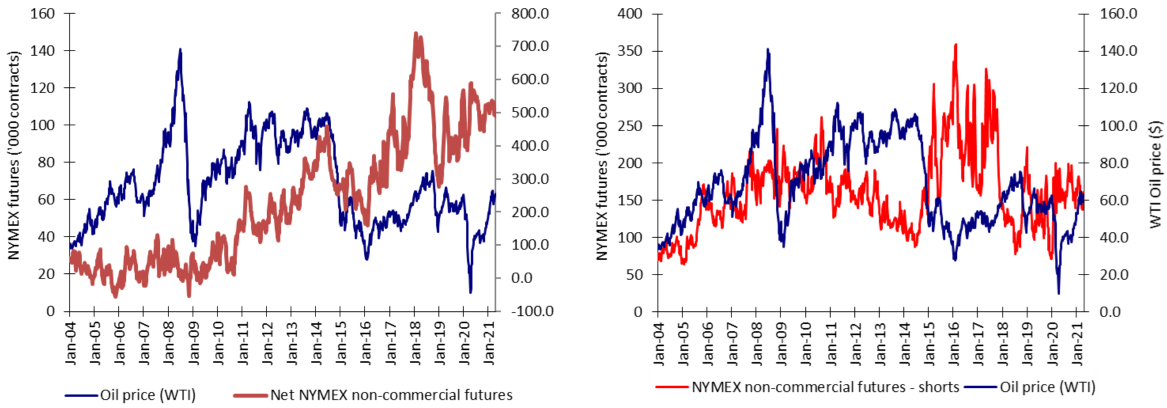
Factors which weakened WTI and Brent oil prices in April:

- **Rising Iranian exports**
  In line with market rumours at the time, it appears that Iranian oil exports are steadily increasing. In March, according to the IEA, Iran produced 2.35m b/d (up 0.06m b/day on the February level and up 0.33m b/day on the December 2019 level). It is thought that many of the country's state-owned oil tankers have turned off their satellite tracking systems to cloak their shipments, and Iran is also using ship-to-ship transfers to sell its oil at ports in the Persian Gulf and parts of Southeast Asia around Malaysia and Indonesia. Talks around the JCPOA nuclear agreement continued throughout the month in Vienna.

Speculative and investment flows

The New York Mercantile Exchange (NYMEX) net non-commercial crude oil futures open position was 489,000 contracts long at the end of April versus 531,000 contracts long at the end of March. 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 increased to 160,000 contracts at the end of April versus 140,000 at the end of the previous month.

Figure 2: NYMEX Non-commercial net and short futures contracts: WTI January 2004 – April 2021

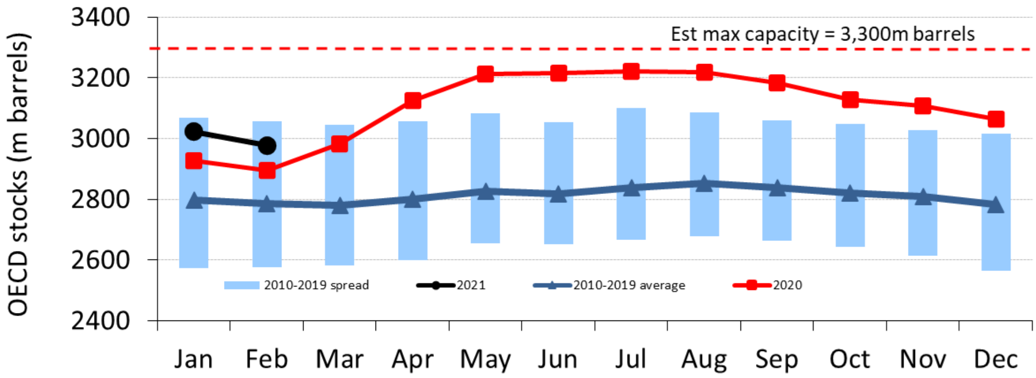


Source: Bloomberg LP/NYMEX/ICE (2021)

OECD stocks

OECD total product and crude inventories at the end of February (latest data point) were estimated by the IEA to be 2,977m barrels, down by 46m barrels versus the level reported for January. This compares to a 10-year average decrease for January of 15m barrels, implying that the OECD market was undersupplied by around 1 million barrels per day. The significant oversupply situation in 2020 pushed OECD inventory levels close to maximum capacity in August (c3.3m barrels), with a tightening thereafter.

Figure 3: OECD total product and crude inventories, monthly, 2004 to 2021



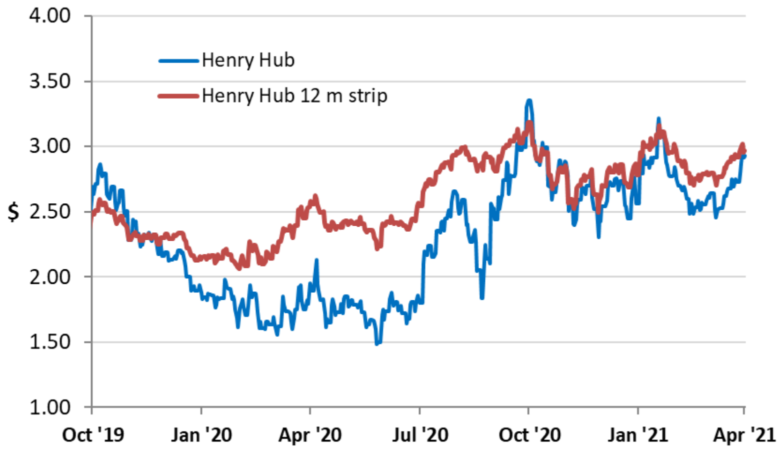
Source: IEA Oil Market Reports (April 2021 and older)

ii) Natural gas market

The US natural gas price (Henry Hub front month) opened April at $2.60/mcf (1,000 cubic feet) and, after dipping slightly at the start of the month, steadily increased to end the month on its highs at $2.94/mcf. The spot gas price has averaged $2.71/mcf so far in 2021, having averaged $2.13/mcf in 2020, $2.53/mcf in 2019 and $3.07 in 2018.

The 12-month gas strip price (a simple average of settlement prices for the next 12 months' futures prices) also rose over the month, opening at $2.78/mcf and closing at $2.97/mcf. The strip price averaged $2.54 in 2020 having averaged $2.60 in 2019, $2.90 in 2018 and $3.12 in 2017.

Figure 4: Henry Hub gas spot price and 12m strip ($/Mcf) 18 months Oct 2019 to April 2021



Source: Bloomberg LP

Factors which strengthened the US gas price in April included:

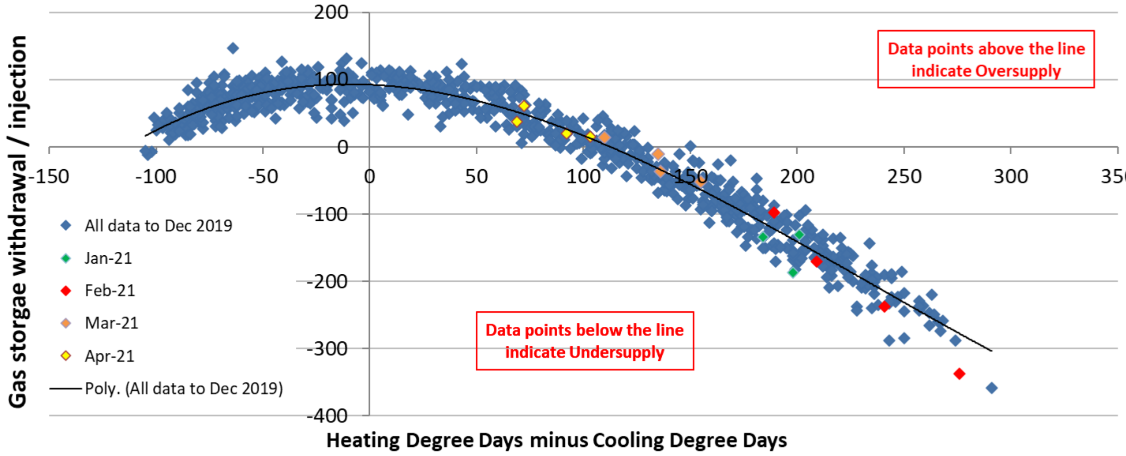
- **Lower than normal international gas inventories and stronger international demand**
  The outlook for international natural gas markets (Asia and Europe) in the remainder of summer 2021 continues to strengthen as European natural gas inventories are currently running 25% below the 5yr average (and around 50% below the 2020 levels), while Asian demand continues to rebound overall. In addition, exports of US natural gas to Mexico are surprisingly strong.

Factors which weakened the US gas price in April included:

- **Market oversupplied, although less than in March**

Withdrawals from US natural gas inventories during April were lower than expected for the time of year. Adjusting for the impact of weather, the builds implied that the US gas market was, on average, around 0.5 Bcf/day oversupplied. The market was slightly less oversupplied in April than it had been in March, having previously seen several months of market tightening.

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

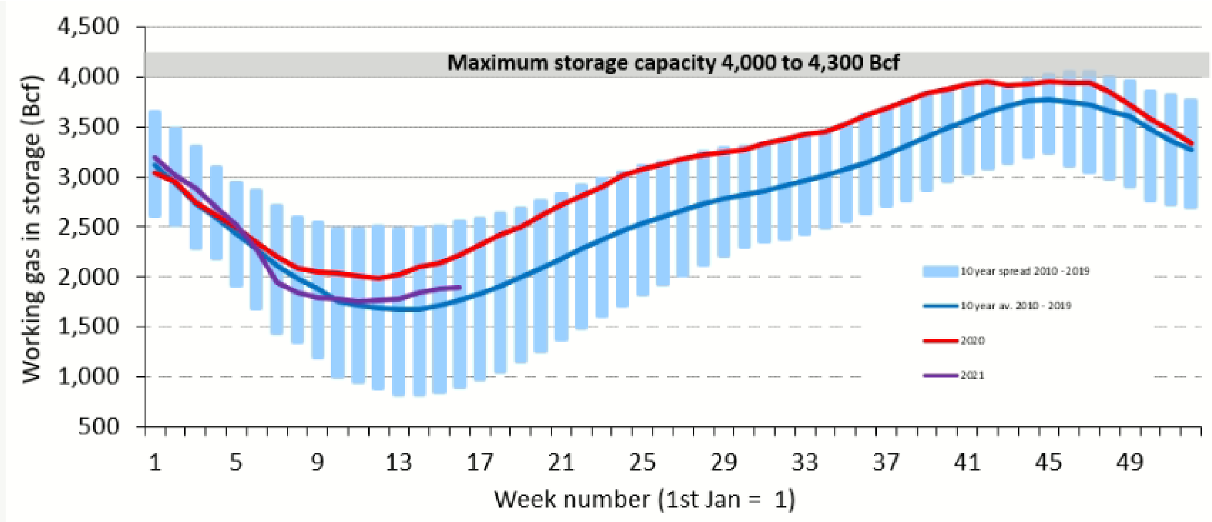


Source: Bloomberg LP; Guinness Asset Management

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 April were reported by the EIA to be 1.9 Tcf. Current gas in storage is around 140 Bcf higher than the 10-year average.

Figure 6: Deviation from 5yr gas storage norm



Source: Bloomberg; EIA (April 2021)

2. MANAGER'S COMMENTS

Effect of COVID on upstream investment and the long-term oil supply outlook

While oil prices have recovered post COVID, the effects of the pandemic will be felt in the industry for a number of years. Investment in oil and gas projects fell nearly 30% in 2020 and there are signs of only limited increases in 2021. Here we review the investments into new oil projects and assess the potential impact on future production and oil prices.

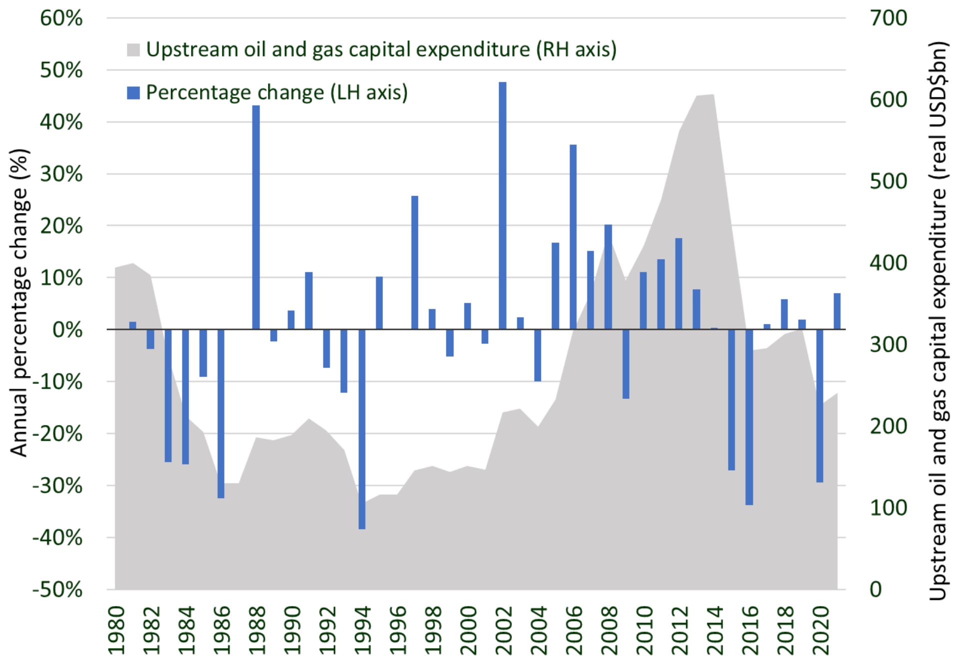
Upstream oil and gas capital expenditure fell in 2020 by 28% to US$225bn, the lowest level since 2005, as sharply lower oil prices reduced operating cash flow for oil and gas companies. This is the third reduction in excess of 25% that the industry has suffered in the last six years, bringing the 2020 spend a level that is 60% lower than the 2014 peak of $553bn.

At the start of 2020, capital investment was forecast to go up around 5%, in line with the average increases of the previous three years, but the onset of COVID-related transportation lockdowns caused oil and gas companies to reduce their planned expenditure levels by nearly one third.

Looking into 2021, the outlook remains muted as a result of the continuing COVID concerns, with total upstream investment expected to recover only marginally, 7%, reaching around US$240bn.

Upstream oil and gas capital expenditure (US$bn)

source: JP Morgan, IEA, Wood Mackenzie, Guinness Asset Management estimates



Looking at how various companies, regions and projects have been affected:

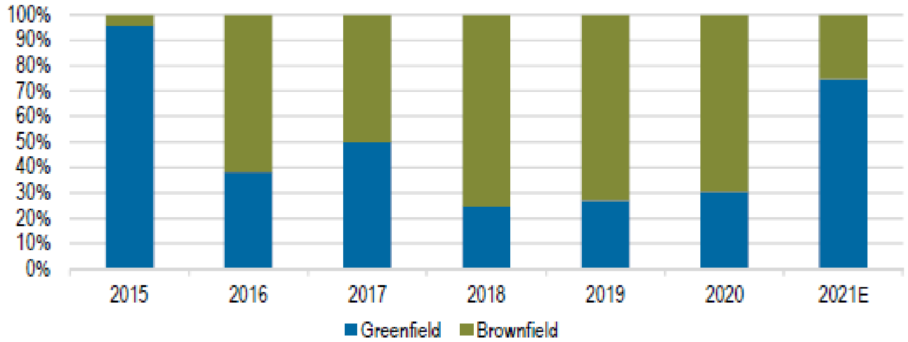
- The **five super majors** reduced their upstream capex by 30% in 2020 and their recent guidance indicates that spending will likely increase by around 20% (to a level that is 15% below the 2019 spend) while focus continues on debt control, dividends, buybacks and the opportunities within the energy transition.
- The **US shale E&Ps** reacted harder, cutting 2020 capital expenditure by around 50% in an effort to maximise their net cash generation and to defend their balance sheets. Historically, the capital expenditure of this group of companies has been heavily driven by the oil price but the outlook is less

clear currently. While WTI oil has recovered sharply to average $58/bl in 1Q2021, the US oil directed rig count has only recovered by around 160 rigs from the trough (reaching 324 rigs currently), giving an initial indication that this group of companies may be becoming more capital disciplined. Current guidance suggests that capital expenditure for the group will increase in 2021 by around 5% but we remain wary that US shale projects economics are currently attractive and that the companies are still incentivised to grow their production.

- The **National Oil Companies (NOCs)** as a group cut capex less, by around 20%, as a result of national demands to sustain investment programmes and access required resources. As a result of their resilience, this group now represents nearly half of all global upstream capital expenditure (47% in 2021, having been 39% in 2014) while the Majors represent only 18% (down from 21% in 2014).
- It appears that **all regions globally** have been affected by the investment decline, with the US suffering more than half of the total decline in 2020. South America appears to have performed the strongest overall, with 2021 capital investment likely to rebound back to around 2019 levels.
- In terms of **project type**, the focus of investment was maintained towards 'brownfield' projects (including projects such as satellite developments, subsea tiebacks and enhanced oil recovery) at the expense of new 'greenfield' projects that are typically more capital intensive in their initial years. The switch to brownfield projects came in 2016, after the 2015 oil price collapse, allowing the industry to deliver greater near-term efficiencies. However, these opportunities appear to have been exhausted and a return to greenfield projects is now inevitable.

Investment into greenfield oil/liquids projects versus brownfield

source: JP Morgan, Wood Mackenzie

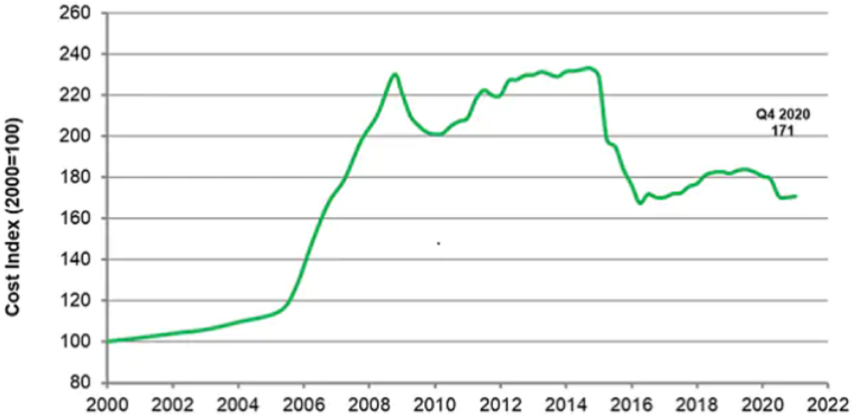


The 'downcycle' silver lining – lower activity means lower unit costs

The oil and gas industry is a typical capital-intensive industry in that it exhibits unit cost inflation when the investment cycle is improving and unit cost deflation when investment cycle is declining. According to the IHS Markit upstream capital cost index, cost inflation was particularly extreme in the 2000 to 2008 period (costs rose by around 130% over the period) and then cost deflation took effect in the 2014-2016 period (costs fell by around 25%). While small versus the previous periods, we did see further cost deflation in 2020 as a result of COVID, with the IHS index at the end of the year reading a level of 171, a fall of around 5% in 2019 levels.

IHS Markit upstream capital cost index

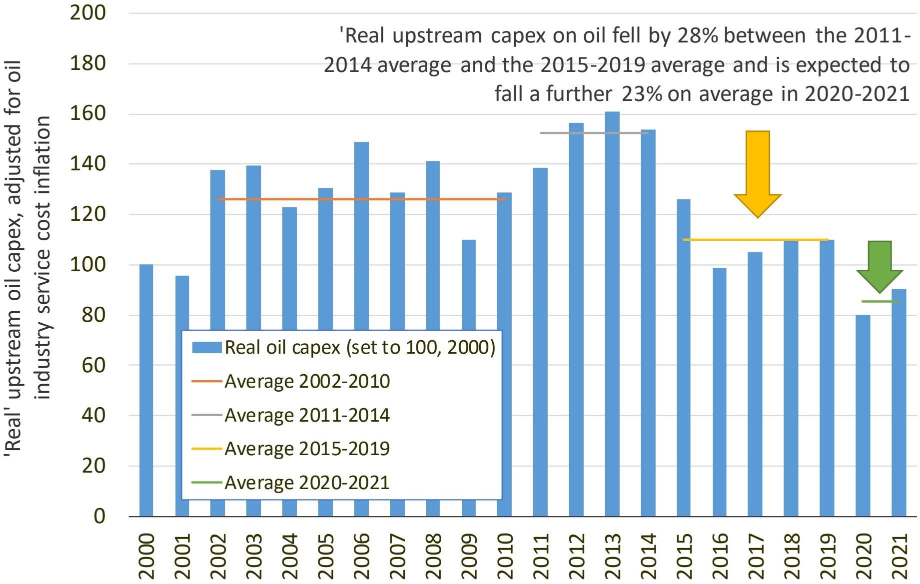
source: IHS Markit



Combining the IHS cost index together with actual capital investment levels, we find that 'real' upstream capex on oil/liquids projects is likely to be down around 23% on average in 2020-2021 versus the level seen in 2015-2019 and 44% down on the peak level seen in 2011-2014 period. The scale of the reduction in real terms is significant and it takes 'real investment' into oil field projects back to the levels last seen in 2000/2001, at the start of the last super-cycle. Global oil production is 22% higher today than it was in 2000/2001, so the relative underinvestment is arguably more extreme now than it was back then.

Upstream oil/liquids capital investment (adjusted for oil industry inflation)

source: IHS Markit, JP Morgan, Wood Mackenzie, Guinness Asset Management estimates



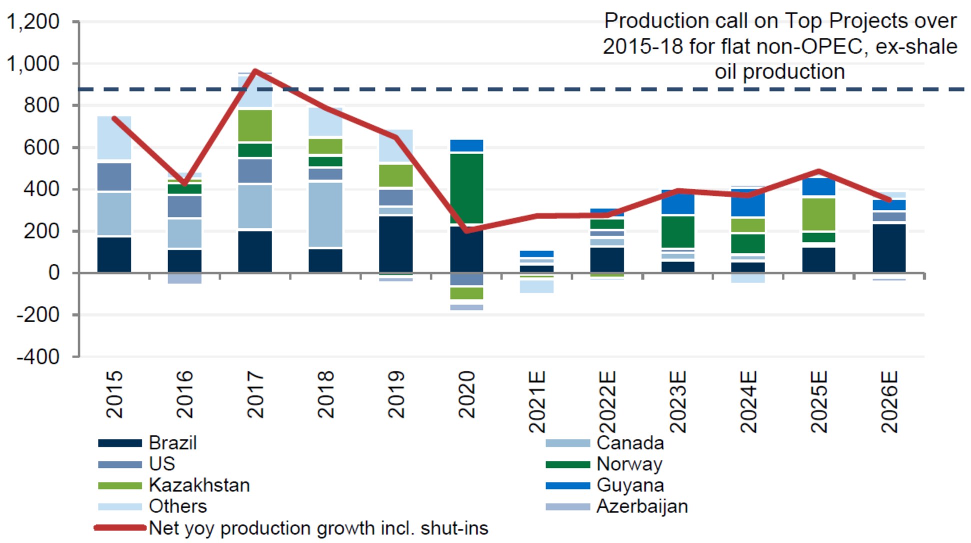
Implications for future production and oil prices

The reduced investment in 2020/2021 further compounds an already weakened outlook for oil project investment, increasing the risk that new large-scale oil projects will not be sufficient to satisfy demand, potentially causing a cyclical upswing in oil prices. We refer here to two significant research pieces by large investment banks that find similar conclusions.

- Using the **Goldman Sachs Top Projects** database, we can track the start-up of new oil and gas projects (ex Russia and the US onshore) over time. These projects are typically long cycle in nature (we estimate they take 3 to 5 years to be developed) and we find that the production outlook in 2021-2026 is around 0.5m b/day lower per year than it was in 2017-2019. This anticipated slow down reflects the lower oil price and lower oil and gas investment seen between 2016 and 2021 and is therefore unlikely to change even if oil prices recover from here. A loss of 0.5m b/day of new project start up every year is likely to have a noticeable effect in tightening oil supply/demand metrics.

Non-OPEC (ex US onshore and Russia) new large project production additions

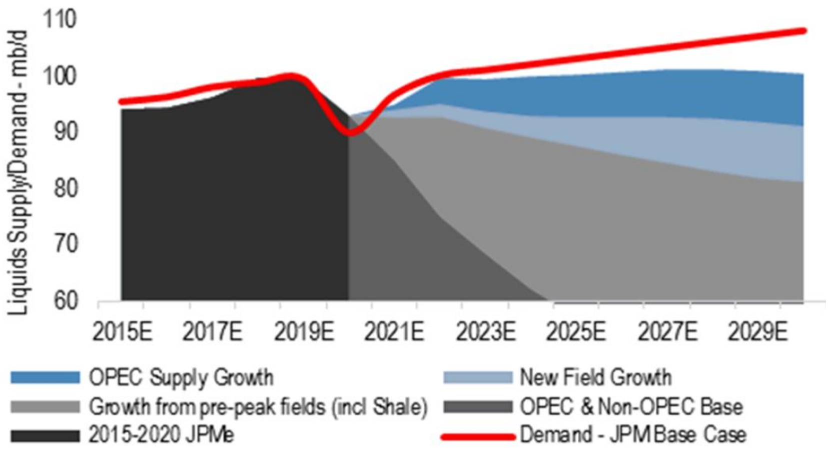
source: Goldman Sachs



- The **JP Morgan "supercycle on the horizon"** thesis places capital discipline and lack of upstream investment as critical factors in driving oil prices above $75/bl in mid 2022. JP Morgan argue that the International Oil Companies (IOCs) are not ready to invest in response to global demand recovery (which is gathering pace) because a 'straight-jacket' of debt reduction, dividends and decarbonization is starving the industry of the capital needed to meet future oil demand. On their calculations, the industry is depleting reserves at record rates and it is still destined to spend $600bn less than is needed to satisfy longer term demand growth.

Lower investment means long term world oil supply does not match demand

source: JP Morgan



In conclusion, the sharply lower reinvestment into upstream projects, especially oil-related projects, is likely to have noticeable impact on future supply delivery of the non-OPEC ex US onshore. Higher oil prices in the near term are unlikely to change this outlook, suggesting that there will be increasing reliance upon OPEC to satisfy global oil demand growth in the years ahead.

3. PERFORMANCE Guinness Global Energy Fund

The main index of oil and gas equities, the MSCI World Energy Index (net return), rose by 0.4% in April, while the MSCI World Index (net return) rose by 4.7%. The Fund was up by 0.2% (class Y*) in the month, underperforming the MSCI World Energy index by 0.2% (all in US dollar terms).

Within the Fund, February's strongest performers were Imperial Oil, Equinor, Devon Energy and Enbridge while the weakest performers were Total, Repsol, Royal Dutch Shell, Helix Energy Solutions and Sinopec.

*Class Y formerly named the E class. OCF remains at 0.99%.

Performance (in USD) **30/04/2021**

Cumulative % returns	YTD	1 month	3 months	6 months	1 year	3 years	5 years	From Launch (31/03/08)
Guinness Global Energy Fund (Class Y, 0.99% OCF)	21.8%	0.2%	17.6%	68.6%	35.7%	-34.3%	-24.5%	-41.1%
MSCI World Energy NR Index	22.2%	0.4%	18.8%	63.6%	30.6%	-24.1%	-8.5%	-18.5%
MSCI World Small Cap Energy Index	30.9%	1.7%	23.5%	88.8%	72.1%	-40.3%	-37.9%	-64.1%
50/50 Mix of World Enegy and Small Cap Index	26.6%	1.0%	21.2%	76.2%	51.3%	-32.2%	-23.2%	-41.3%

Calendar year % returns	YTD	2020	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008*
Guinness Global Energy Fund (Class Y, 0.99% OCF)	21.8%	-34.7%	9.8%	-19.7%	-1.3%	27.9%	-27.6%	-19.1%	24.4%	3.0%	-13.7%	15.3%	61.8%	-44.8%
MSCI World Energy NR Index	22.2%	-31.5%	11.4%	-15.8%	5.0%	26.6%	-22.8%	-11.6%	18.1%	1.9%	0.2%	11.9%	26.2%	-32.8%
MSCI World Small Cap Energy Index	30.9%	-30.5%	-2.3%	-31.3%	-12.0%	37.0%	-37.3%	-33.1%	16.4%	1.4%	-9.2%	34.8%	77.5%	-54.7%
50/50 Mix of World Enegy and Small Cap Index	26.6%	-31.0%	4.6%	-23.6%	-3.5%	31.8%	-30.1%	-22.3%	17.3%	1.6%	-4.5%	23.3%	51.9%	-43.8%

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 Y (0.99% OCF) thereafter. Performance would be lower if an initial charge and/or redemption fee were included. Returns for share classes with a different OCF will vary accordingly

TB Guinness Global Energy Fund

UK investors should be aware that the Guinness Global Energy Fund is now available as a UK domiciled fund denominated in GBP. The TB Guinness Global Energy Fund is available from 0.95% OCF. The historical performance of this fund will differ from the Guinness Global Energy Fund as the TB Guinness Global Energy fund has only been recently brought into line with the Guinness Global Energy Fund. 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 Please contact info@guinnessfunds.com or +44 (0) 20 7222 5703 for more details

Past performance should not be taken as an indicator of future performance. The value of this investment and any income arising from it can fall as well as rise as a result of market and currency fluctuations as well as other factors. You may lose money in this investment.

Returns stated above are in US dollars; returns in other currencies may be higher or lower as a result of currency fluctuations. Investors may be subject to tax on distributions.

The Fund's Prospectus gives a full explanation of the characteristics of the Fund and is available at www.guinnessfunds.com.

4. PORTFOLIO Guinness Global Energy Fund

Buys/Sells

There were no buys and sells during the month, but the portfolio was actively rebalanced.

Sector Breakdown

The following table shows the asset allocation of the Fund at **April 30 2021**.

Asset allocation as %NAV	Current	*Change*	Last year end	Previous year ends							
	Apr-21		Dec-20	Dec-19	Dec-18	Dec-17	Dec-16	Dec-15	Dec-14	Dec-13	Dec-12
Oil & Gas	**96.2%**	***1.4%***	**94.8%**	**98.3%**	**96.7%**	**98.4%**	**96.7%**	**95.1%**	**93.7%**	**93.6%**	**98.6%**
Integrated	55.5%	*-0.7%*	56.3%	51.1%	46.4%	42.9%	46.4%	41.5%	37.3%	38.4%	39.1%
Exploration & Production	24.4%	*2.2%*	22.2%	29.6%	35.8%	36.9%	35.8%	36.5%	36.2%	35.2%	41.6%
Drilling	0.0%	*0.0%*	0.0%	0.1%	2.2%	1.9%	2.2%	1.5%	3.3%	7.0%	7.4%
Equipment & Services	4.5%	*-0.1%*	4.6%	9.6%	8.6%	9.5%	8.6%	11.4%	13.4%	9.8%	7.1%
Storage & Transportation	4.5%	*0.0%*	4.4%	4.0%	0.0%	3.5%	0.0%	0.0%	0.0%	0.0%	0.0%
Refining & Marketing	7.3%	*0.0%*	7.3%	3.8%	3.7%	3.7%	3.7%	4.2%	3.5%	3.1%	3.4%
Solar	1.4%	*-0.4%*	1.8%	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%	0.0%
Construction & Engineering	0.0%	*0.0%*	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.2%	0.6%
Cash	2.3%	*-1.0%*	3.3%	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 end of April 2021 was on a price to earnings ratio (P/E) for 2020/2021 of 55.8x/11.5x versus the MSCI World Index at 35.7x/20.6x as set out in the following table:

As at 30 April 2021	P/E		
	2020	2021E	2022E
Guinness Global Energy Fund	55.8x	11.5x	9.8x
MSCI World Index	35.7x	20.6x	18.5x
Fund Premium/(Discount)	*56%*	*-44%*	*-47%*

Source: Bloomberg; Guinness Asset Management Ltd

Portfolio holdings

Our integrated and similar stock exposure (c.56%) is comprised of a mix of mid cap, mid/large cap and large cap stocks. Our five large caps are Chevron, BP, ExxonMobil, Royal Dutch Shell and Total. Mid/large and mid-caps are ENI, Equinor, GALP, Repsol and OMV. At April 30 2021 the median P/E ratio of this group was 10.8x 2021 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.24%) 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 (EOG, Pioneer and Devon), with one other name (ConocoPhillips) having a mix of US and international production. One of the key metrics behind a number of the E&P stocks held is low enterprise value / proven reserves.

We have exposure to five (pure) emerging market stocks in the main portfolio, though one is a half-position, and in total represent 16% of the portfolio. Two are classified as integrateds (Gazprom and PetroChina), one as refining (Sinopec) 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 4.2x 2021 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.

The portfolio contains one midstream holding, Enbridge, North America's largest pipeline company. With the growth of hydrocarbon demand 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 5% of the portfolio. The stocks we own are mainly diversified internationally (Helix 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 March 31 2021 (for compliance reasons disclosed one month in arrears)

Guinness Global Energy Fund (31 March 2021)			P/E			EV/EBITDA			Price/Book		
Stock	**ISIN**	**% of NAV**	**2019**	**2020E**	**2021E**	**2019**	**2020E**	**2021E**	**2019**	**2020E**	**2021E**
Integrated Oil & Gas											
Exxon Mobil Corp	US30231G1022	4.8%	23.8x	n/a	18.9x	8.2x	15.5x	7.4x	1.2x	1.4x	1.5x
Chevron Corp	US1667641005	4.6%	16.6x	n/a	21.1x	6.7x	13.9x	7.1x	1.3x	1.5x	1.5x
Royal Dutch Shell PLC	GB00B03MLX29	4.1%	9.2x	31.5x	9.5x	4.0x	6.9x	4.8x	0.9x	1.0x	0.9x
Total SA	FR0000120271	4.1%	10.7x	32.4x	12.1x	4.9x	8.6x	5.4x	1.0x	1.1x	1.2x
BP PLC	GB0007980591	4.3%	8.5x	n/a	10.3x	4.0x	10.9x	4.9x	0.9x	1.1x	1.1x
Equinor ASA	NO0010096985	3.9%	13.1x	35.2x	12.2x	3.4x	4.5x	3.3x	1.6x	1.8x	1.7x
ENI SpA	IT0003132476	3.8%	13.0x	n/a	15.8x	3.4x	5.6x	3.8x	0.8x	0.9x	1.0x
Repsol SA	ES0173516115	3.9%	8.5x	49.0x	10.8x	3.9x	6.3x	4.7x	0.6x	0.7x	0.8x
Galp Energia SGPS SA	PTGAL0AM0009	3.3%	15.4x	n/a	18.9x	5.2x	6.9x	5.3x	2.0x	2.2x	2.4x
OMV AG	AT0000743059	4.2%	8.8x	20.1x	9.4x	5.7x	8.3x	5.4x	1.1x	1.0x	1.0x
		41.2%									
Integrated / Oil & Gas E&P - Canada											
Suncor Energy Inc	CA8672241079	4.0%	8.8x	n/a	12.1x	4.5x	12.6x	5.0x	1.0x	1.2x	1.1x
Canadian Natural Resources Ltd	CA1363851017	3.4%	12.5x	n/a	11.5x	6.1x	11.7x	5.2x	1.4x	1.5x	1.4x
Imperial Oil Ltd	CA4530384086	4.0%	12.4x	n/a	11.4x	7.0x	28.8x	5.3x	1.0x	1.0x	1.0x
		11.4%									
Integrated Oil & Gas - Emerging market											
PetroChina Co Ltd	CNE1000003W8	3.3%	10.0x	22.6x	8.8x	4.0x	4.4x	3.8x	0.4x	0.3x	0.3x
Gazprom PJSC	US3682872078	3.6%	3.9x	142.0x	4.5x	4.4x	6.5x	4.0x	0.3x	0.3x	0.3x
		6.8%									
Oil & Gas E&P											
ConocoPhillips	US20825C1045	3.7%	14.5x	n/a	22.3x	5.3x	15.1x	6.2x	1.7x	1.9x	1.7x
EOG Resources Inc	US26875P1012	4.2%	15.0x	66.2x	14.4x	5.6x	9.2x	5.4x	1.9x	2.1x	1.8x
Pioneer Natural Resources Co	US7237871071	4.3%	20.1x	101.7x	17.4x	10.9x	17.5x	7.4x	2.2x	2.2x	1.7x
Devon Energy Corp	US25179M1036	4.0%	15.9x	n/a	12.3x	7.5x	12.9x	4.9x	1.4x	2.6x	1.9x
		16.1%									
International E&Ps											
CNOOC Ltd	HK0883013259	2.4%	5.7x	12.3x	5.4x	2.5x	3.5x	2.3x	0.7x	0.7x	0.7x
Pharos Energy PLC	GB00B572ZV91	0.3%	19.7x	n/a	n/a	1.5x	2.1x	2.0x	0.2x	n/a	n/a
		2.7%									
Midstream											
Enbridge Inc	CA29250N1050	4.3%	18.1x	18.8x	17.0x	12.5x	11.9x	11.2x	1.6x	1.6x	1.7x
		4.3%									
Equipment & Services											
Schlumberger Ltd	AN8068571086	3.7%	18.7x	42.3x	27.2x	8.0x	12.5x	11.5x	1.3x	3.2x	2.9x
Helix Energy Solutions Group Inc	US42330P1075	0.9%	14.3x	n/a	n/a	4.5x	5.7x	7.1x	n/a	0.4x	0.5x
		4.6%									
Oil & Gas Refining & Marketing											
China Petroleum & Chemical Corp	CNE1000002Q2	3.3%	8.1x	12.1x	7.6x	4.5x	5.8x	4.2x	0.6x	0.6x	0.5x
Valero Energy Corp	US91913Y1001	4.2%	14.5x	n/a	71.7x	7.3x	38.8x	10.4x	1.4x	1.7x	1.8x
		7.5%									
Research Portfolio											
Deltic Energy PLC	GB00B6SYKF01	0.3%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
EnQuest PLC	GB00B635TG28	0.5%	2.3x	n/a	4.6x	1.7x	3.3x	2.7x	0.4x	1.7x	2.7x
JKX Oil & Gas PLC	GB0004697420	0.1%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Reabold Resources PLC	GB00B95L0551	0.4%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Sunpower Corp	US8676524064	1.7%	n/a	n/a	124.3x	56.4x	195.8x	48.9x	n/a	477.9x	10.5x
Maxeon Solar Technologies Ltd	SGXZ25336314	0.2%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Diversified Gas & Oil Company	GB00BYX7JT74	0.6%	9.0x	6.7x	9.6x	6.3x	5.8x	5.9x	n/a	1.1x	1.2x
		3.9%									
Cash	Cash	**1.4%**									

The Fund's portfolio may change significantly over a short period of time; no recommendation is made for the purchase or sale of any particular stock.

5. OUTLOOK

i) Oil market

The table below illustrates the difference between the growth in world oil demand and non-OPEC supply since 2015:

	2015	2016	2017	2018	2019	2020	2021E
					IEA	*IEA*	*IEA*
World Demand	*95.3*	*96.4*	*98.2*	*99.3*	*99.7*	*91.0*	*96.7*
Non-OPEC supply (inc NGLs)	*60.3*	*59.8*	*60.8*	*63.6*	*65.6*	*63.1*	*63.8*
OPEC NGLs	*5.2*	*5.3*	*5.4*	*5.5*	*5.4*	*5.2*	*5.2*
Non-OPEC supply plus OPEC NGLs	**65.5**	**65.1**	**66.2**	**69.1**	**71.0**	**68.3**	**69.0**
Call on OPEC (crude oil)	**29.8**	**31.3**	**32.0**	**30.2**	**28.7**	**22.7**	**27.7**
Congo supply adjustment	0.3	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	0.2
Eq Guinea supply adjustment	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Call on OPEC-10 (crude oil)	**29.2**	**30.7**	**31.4**	**29.6**	**28.1**	**22.1**	**27.1**

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 demand picture for 2020, down by nearly 9m b/day, was heavily clouded by the impact of the COVID-19 virus and efforts to mitigate its spread. The IEA's best estimate is that demand will recover this year by around 5.5m b/day, leaving overall consumption on a par with 2016 but still around 3m b/day below the 2019 peak.

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.

('000 b/day)	31-Dec-19	31-Mar-21	30-Apr-21	Current vs Dec 2019	Current vs last month
Saudi	9,730	8,150	**8,110**	-1,620	-40
Iran	2,080	2,350	**2,410**	330	60
Iraq	4,610	3,940	**3,950**	-660	10
UAE	3,040	2,630	**2,620**	-420	-10
Kuwait	2,710	2,320	**2,320**	-390	0
Nigeria	1,820	1,550	**1,590**	-230	40
Venezuela	730	490	**490**	-240	0
Angola	1,390	1,200	**1,180**	-210	-20
Libya	1,110	1,220	**1,140**	30	-80
Algeria	1,010	880	**880**	-130	0
OPEC-10	**28,230**	**24,730**	**24,690**	**-3,540**	**-40**

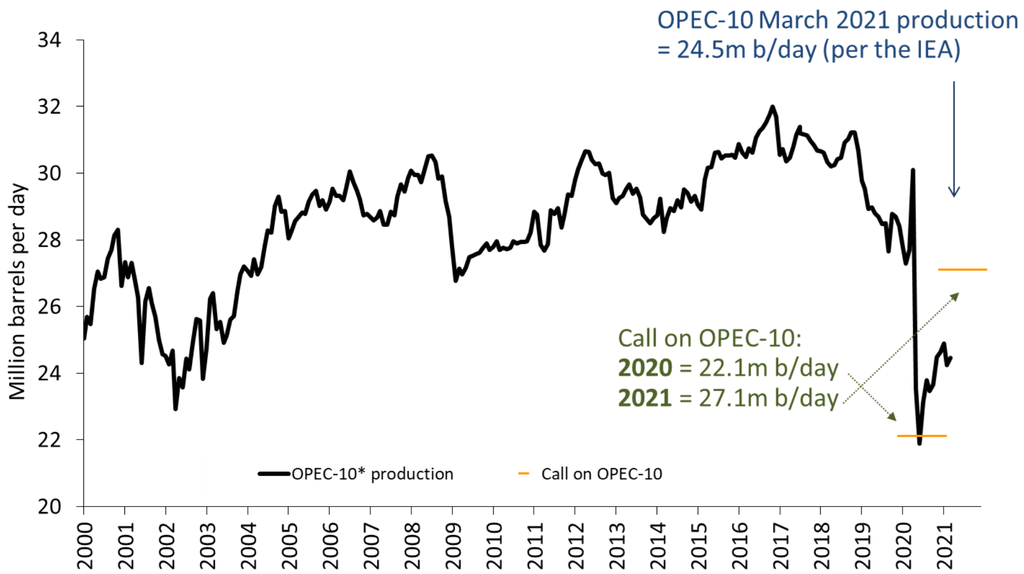
Source: Bloomberg, DOE

Source: Bloomberg; Guinness Asset Management

The 2017-19 period continued to see a volatile time for OPEC with further production cuts necessary to balance ongoing non-OPEC supply growth.

The challenge for OPEC then ballooned in 2020 with the onset of COVID around the world. Initially, OPEC and their non-OPEC partners failed to reach agreement around their response to demand from the spread of the virus, precipitating a fall-out between participants and a short-lived price war. In light of extreme oil market oversupply, OPEC and non-OPEC partners reconvened in April 2020 and confirmed a deal to cut their production by 9.7m b/day, relative to their 'baseline' production level of October 2018. The cuts extend until April 2022, gradually stepping down in size over the period. The agreement gives us confidence that OPEC is looking to do 'what it takes' to bring the market back into balance, despite extreme challenges in the shorter term.

Figure 7: OPEC-10 apparent production vs call on OPEC 2000 – 2021



Source: IEA Oil Market Report (March 2021 and prior); Guinness estimates

OPEC's actions in recent years have generally demonstrated 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 have been designed to achieve an oil price that to some extent closes their fiscal deficit (c.$70/bl is needed to close the gap fully), whilst not spiking the oil price too high and over-stimulating non-OPEC supply.

In the shorter term, the COVID-19 crisis has created particularly challenging conditions. Longer term, however, we believe that Saudi seek a 'good' oil price, well in excess of current levels to balance their fiscal needs, but they realise that patience is required to achieve that goal.

Overall, we reiterate two important criteria for Saudi:

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

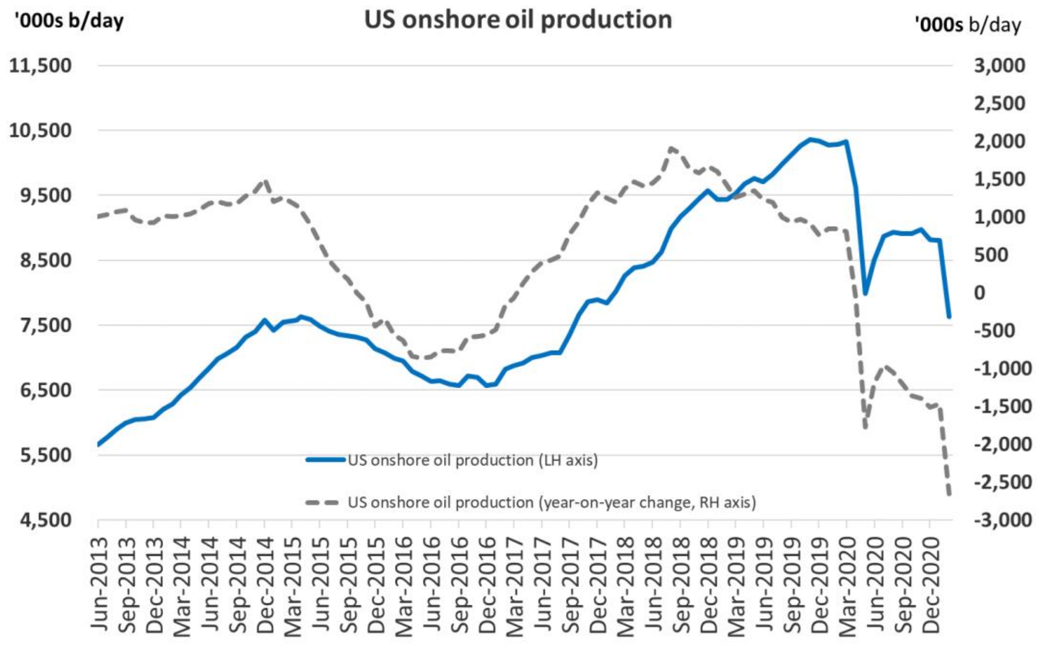
Nothing in the market in recent years has changed our view that OPEC can put a floor under the price – as they did in 2018, 2016, 2008, 2006, 2001, 1998. Saudi's desire for a $60 oil price floor is not dimmed.

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 last decade has been dominated by the 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.

Figure 8: US onshore oil production



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. Our assessment is that US shale oil is a capital intensive source of oil but one where some 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. During 2019 and 2020, we started to see increased pressure on US E&P companies to improve their capital discipline and to cut their reinvestment rates, and this is evidenced by higher costs of capital being charged to the US E&P companies.

The collapse in oil prices at the start of 2020 to a level well below $50/bl changed the landscape, with US E&P companies significantly reducing capital spending as they attempt to live within their cashflows. The reduction in activity will cause US shale supply to decline in 2021.

Non-OPEC supply growth outside the US has been sustained in recent years, despite lower oil prices, since projects that were sanctioned before 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 (excluding the fall in early 2020 as a result of voluntary curtailments amid the COVID-19 demand shock), as new investment has simply offset the decline profiles of existing production.

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 as only being viable at high oil prices.

Demand looking forward

The IEA report that 2020 oil demand declined by 8.7m b/day, taking demand to 91.0m b/day. The spread of the COVID virus globally caused major restrictions to the movement of people, which in turn caused a major contraction in oil consumption.

As we emerge from the worst of COVID, we expect initially a sharp demand recovery, then for the world to settle back into oil demand growth of around 1m b/day, led by increased use in Asia. 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.

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 (ex COVID effects) at a rate of around 1% per year.

The trajectory of global oil demand over the next few years will be a function of global GDP, pace of the 'consumerisation' of developing economies, the development of alternative fuels and price. At a $50/bl oil price, the world oil bill as a percentage of GDP is around 2.0% and this will still be a stimulant of further 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 little 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 3.1m in 2020, up from 2.3m in 2019. We expect to see strong EV sales growth again in 2021, up to around 4.4m, or 5% of total global sales. Even applying an aggressive growth rate to EV sales, we see EVs comprising only around 2% of the global car fleet by the end of 2022. 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 around 2030.

Conclusions about oil

The table below summarises our view by showing our oil price forecasts for WTI and Brent in 2021 versus recent history.

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	2021
WTI	30	33	38	49	66	75	82	104	68	84	99	94	98	93	49	45	51	65	57	40	49
Brent	30	32	35	46	64	75	82	103	67	84	115	112	108	99	52	45	54	72	60	42	55
Brent/WTI (12m MAV)	**30**	**33**	**37**	**48**	**65**	**75**	**82**	**104**	**68**	**84**	**107**	**103**	**103**	**96**	**51**	**45**	**53**	**68**	**59**	**41**	**52**
Brent/WTI y-on-y change (%)		8%	12%	30%	37%	15%	9%	26%	-35%	24%	27%	-4%	0%	-7%	-47%	-11%	17%	30%	-14%	-30%	27%
Brent/WTI (5yr MAV)	30	25	32	37	42	51	61	75	79	82	89	93	93	99	92	80	69	63	55	53	54

Source: Guinness Asset Management, Bloomberg

We believe that Saudi's long-term objective remains to maintain a 'good' oil price, something north of $60/bl. The world oil bill at around $60/bl represents 2.5% of 2021 Global GDP, 26% under the average of the 1970 – 2015 period (3.4%).

Natural gas market

US gas demand

On the demand side for the US, industrial gas demand and power generation gas demand, each about 25-30% 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	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021E
US natural gas demand:										
Residential/commercial	19.2	22.4	23.4	21.4	20.5	20.9	23.4	23.5	21.6	22.1
Power generation	24.9	22.3	22.3	26.5	27.3	25.3	29.0	30.9	31.8	30.6
Industrial	19.7	20.3	20.9	20.6	21.1	21.6	23.0	23.0	22.5	23.2
Pipeline exports (Mexico)	1.8	1.9	1.9	2.7	3.8	4.0	4.6	5.1	5.4	6.1
LNG exports	-	-	-	0.1	1.0	2.6	3.4	5.7	7.3	10.3
Pipeline/plant/other	6.1	6.7	6.3	6.5	6.4	6.5	7.1	7.6	7.6	7.7
Total demand	**71.7**	**73.6**	**74.8**	**77.8**	**80.1**	**80.9**	**90.5**	**95.8**	**96.2**	**100.0**
Demand growth	**3.1**	**1.9**	**1.2**	**3.0**	**2.3**	**0.8**	**9.6**	**5.3**	**0.4**	**3.8**

Source: Guinness estimates; GS (March 2021)

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 2020, 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 2020 (including Mexican and LNG exports) was around 96.2 Bcf/day, up by 0.4 Bcf/day versus 2019 and 11 Bcf/day (13%) higher than the 5 year average. The biggest contributors to the growth in demand in 2020 were power generation (numerous gas plants increasing gas' share over coal) and LNG exports (opening of new export terminals). Commercial demand for gas was lower, however, driven by COVID mitigation measures.

We expect US demand in 2021, assuming prices remain around $2.75/mcf, to be up by around 4 Bcf/day. The key change is a ramp up of LNG exports (+3 Bcf/day vs 2020, thanks to new terminals coming into full operation and arbitrage between US and European gas prices looking better).

Looking further ahead to 2025, we believe that gas will take a good share of incremental power generation growth in the US and continue to take market share from coal. 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.

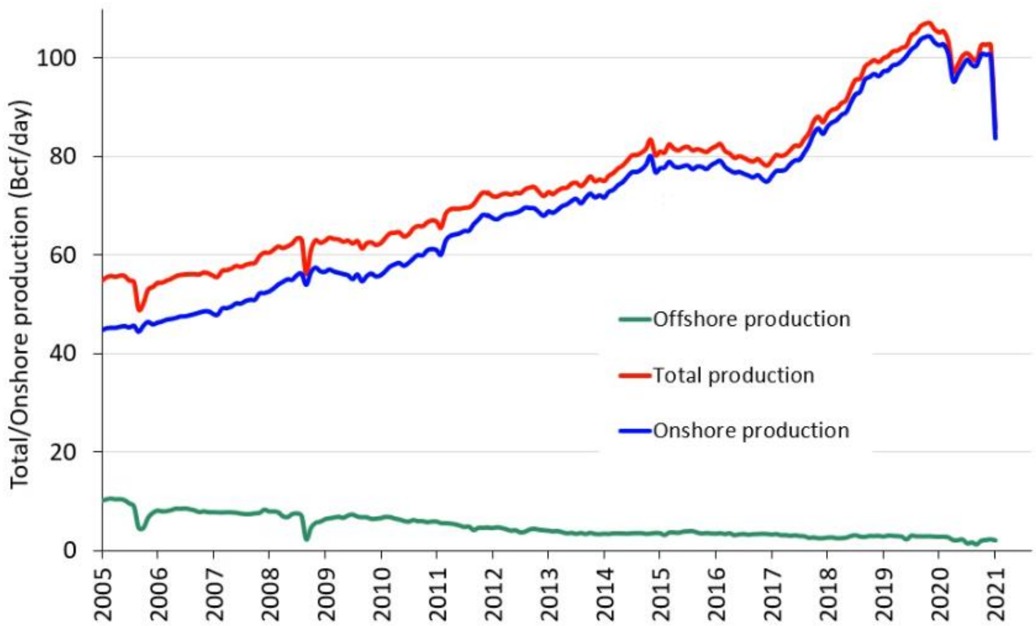
Figure 12: US natural gas supply

Bcf/day	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021E
US natural gas supply:										
US (onshore & offshore)	65.7	66.3	70.9	74.2	73.4	73.6	84.0	92.3	92.2	91.8
Net imports (Canada)	5.4	5.0	4.9	4.9	5.5	5.8	5.4	4.7	4.5	5.1
LNG imports & other	0.8	0.6	0.5	0.5	0.4	0.3	0.1	0.1	-	0.1
Total supply	**71.9**	**71.9**	**76.3**	**79.6**	**79.3**	**79.7**	**89.5**	**97.1**	**96.7**	**97.0**
Supply growth	**2.4**	**-**	**4.4**	**3.3**	**- 0.3**	**0.4**	**9.8**	**7.6**	**- 0.4**	**0.3**
(Supply)/demand balance	**- 0.2**	**1.7**	**- 1.5**	**- 1.8**	**0.8**	**1.2**	**1.0**	**- 1.3**	**- 0.5**	**3.0**

Source: EIA; Simmons; Guinness estimates

Over the last 10 years, 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 76 at the end of January 2021. 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) fell sharply in February 2021 to average 85.6 Bcf/day as a result of extreme cold weather affecting supply in Texas. Prior to that, onshore gas supply had been running far above the 57.4 Bcf/day peak in November 2008 before the rig count collapsed.

Figure 13: US natural gross gas production 2005 – 2021 (Lower 48 States)



Source: EIA 914 data (March 2021 data)

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 2020 with the fall of shale oil production, and with US oil supply now flattening, so associated gas production has also moderated. Generally, we expect to see rates of around 2-3 Bcf/day of associated gas per 1m b/day of oil production growth.

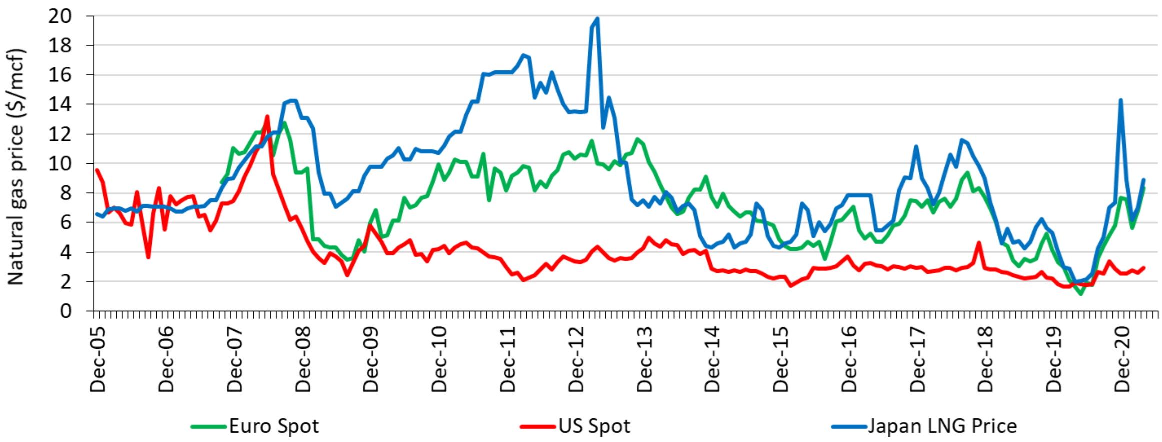
The Marcellus/Utica region, which includes the largest producing gas field in the US and the surrounding region, reached production of around 32 Bcf/day in 2020. Moderate growth is likely in 2021.

Overall, if the price remains in the $2.50-$4/mcf range, we expect a small rise in average onshore gas supply in 2021, up by around 1 Bcf/day versus 2020.

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 – has moved to a premium to the US gas price (c.$8/mcf versus c.$3/mcf). Asian spot LNG prices spiked at the very end of 2020 but have already moderated to around $8/mcf. The implied economics for US LNG exports into Europe and Asia are reasonably attractive assuming international prices are over $5/mcf.

Figure 14: International gas prices to April 2021



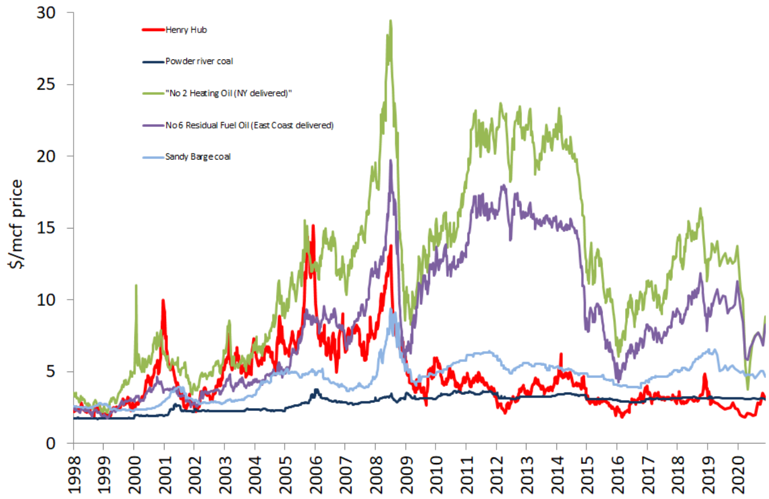
Source: Bloomberg (March 2021)

Relationship with oil and coal

The oil/gas price ratio ($ per bbl WTI/$ per mcf Henry Hub) of around 22x at the end of April 2021 sits 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 15: 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; Guinness Asset Management (March 2021)

Conclusions about US natural gas

The US natural gas price was held back over the last decade by continued strength in gas supply, particularly from the Marcellus/Utica and from gas produced as a by-product of shale oil. Natural gas prices averaged $2.13/mcf in 2020, but we suspect that the (full cycle) marginal cost of supply is now around $3/mcf. A drop in associated gas supply over the next couple of years, thanks to lower oil prices, should allow gas prices to normalise closer to $3/mcf, though demand in the short-term is clouded by COVID-19.

6. APPENDIX Oil and gas markets historical context

Figure 16: 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 three distinct periods:

1) **1990-1998:** 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.

2) **1998-2014:** 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.

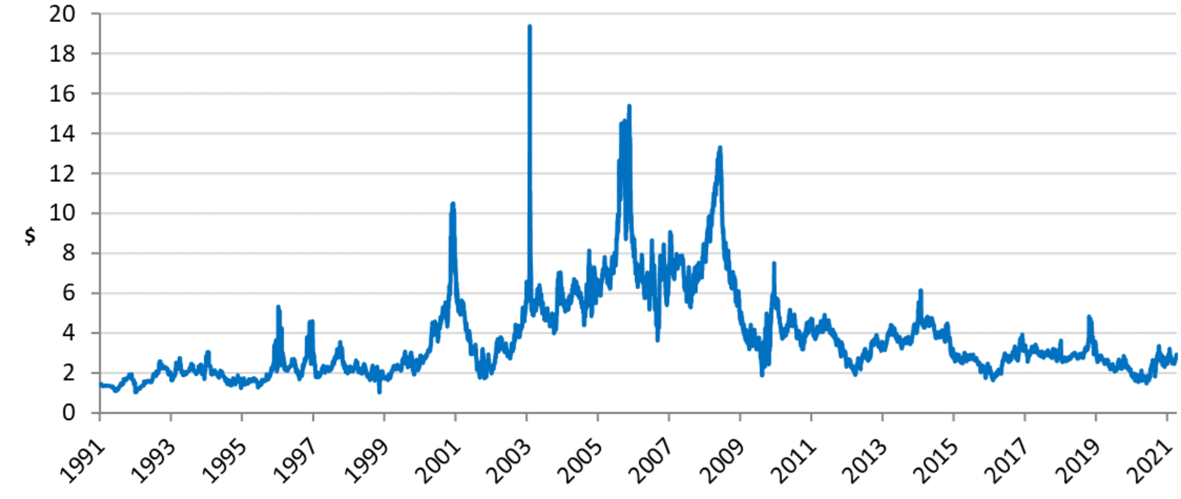
Continued expectations of a supply crunch by the end of the decade, coupled with increased speculative activity in oil markets, contributed to the oil price surging past $90 in the final months of 2007 and as high as $147 by the middle of 2008. This spike was brought to an abrupt end by the collapse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

3) **2014-2021:** a further downcycle in oil. Ten years of high prices leading up to 2014 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 and non-OPEC partners 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. Average prices were pinned 2017-19 in the $50-70/bl range, with prices at the top end of this rang stimulating oversupply from US shale.

The alliance between OPEC and non-OPEC partners fell apart briefly in March 2020 and, coupled with an unprecedented collapse in demand owing to the COVID-19 crisis, oil prices dropped back below $30/bl, before recovering to around $50/bl by the end of 2020 thanks to renewed OPEC+ action.

Figure 17: 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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