The Guinness Global Energy Report

Developments and trends for investors in the global energy sector

This is a marketing communication. Please refer to the prospectus and KIID for the Fund before making any final investment decisions. Past performance does not predict future returns.

August 2022

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 actively managed and uses the MSCI World Energy Index as a comparator benchmark only.

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.

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.

◀ Lower risk			Risk & reward			Higher risk ▶
1	2	3	4	5	6	**7**
Typically lower rewards						Typically higher rewards

The risk and reward indicator shows where the fund ranks in terms of its potential risk and return. The fund is ranked as higher risk as its price has shown high fluctuations historically. This is based on how investments have performed in the past and you should note that the fund may perform differently in the future and its rank may change. Historic data may not be a reliable indicator for the future.

HIGHLIGHTS FOR JULY

OIL

Brent/WTI fall as demand destruction concerns build

Brent and WTI spot oil prices fell in July. Brent and WTI closed the month at $108/bl and $99/bl, both down by $7/bl over the month. Five-year forward prices rose by $3/bl, Brent closing at $76/bl and WTI at $69/bl. President Biden visited Saudi Arabia, in part to seek higher oil output from OPEC. He left with no concrete assurances from Saudi, a reflection of the lack of spare capacity OPEC currently has at its disposal. Signs of demand destruction appeared in the US, where gasoline and diesel demand were down a little year-on-year, though falling refined product prices will start to help.

NATURAL GAS

US, European and Asian gas prices spike

The European and Asian gas prices (using UK NBP) closed July at $37/$42 /mcf, whilst the US spot price (Henry Hub) rose to $8.2/mcf. Russian gas flows (in particular Nordstream 1) into Europe dropped, as Putin further 'weaponises' the commodity. US gas prices rose as extremely high temperatures boosted demand for air conditioning.

EQUITIES

Energy underperforms the broad market in July

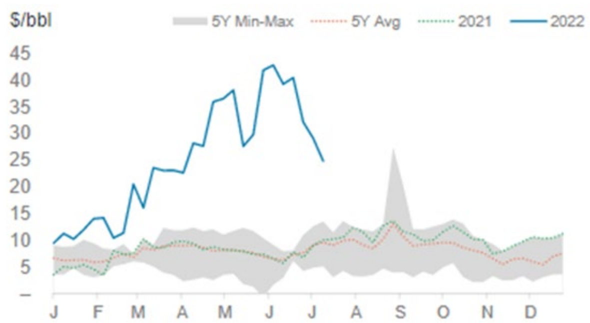
The MSCI World Energy Index (net return) rose by 6.9% in July, underperforming the MSCI World Index (net return) which rose by 7.9% over the month (all in US dollar terms).

CHART OF THE MONTH

US refining margins coming off their highs

In common with most parts of the world, US refining margins have spiked this year, contributing to high refined product prices (e.g. gasoline; diesel; jet fuel). Since the middle of June, refining margins have moderated, coincident with a fall in product prices. Average retail gasoline prices in the US peaked in June, for example, at just below $5/gallon, but have fallen (at time of writing) to around $4.14/gallon. This brings some well-needed relief to the US consumer.

US Gulf coast refining margin



Source: Morgan Stanley

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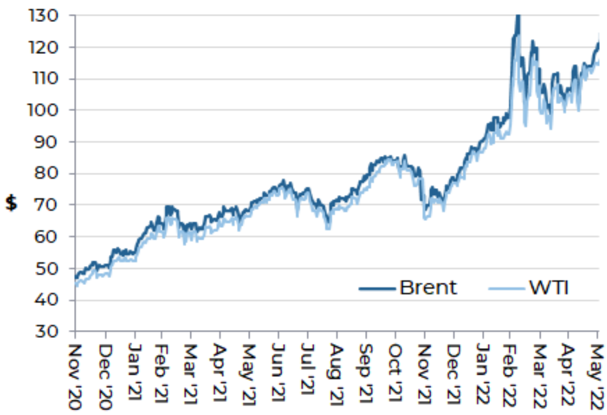
1. JULY IN REVIEW

i) Oil market

Oil price (WTI and Brent $/barrel): Jan 2021 to July 2022



Source: Bloomberg; Guinness Global Investors

The West Texas Intermediate (WTI) oil price started July at $106/bl, generally declined over the month to reach a low of $95/bl on July 26, before closing slightly higher at $99/bl. WTI has averaged $102/bl so far this year, having averaged $68/bl in 2021, $40/bl in 2020 and $58/bl in 2019.

Brent oil traded in a similar shape, opening at $115/bl, troughing at $103/bl and closing the month at $108/bl. Brent has averaged $107/bl so far in 2022, having averaged $70/bl in 2021, $42/bl in 2020 and $64/bl in 2019. The gap between the WTI and Brent benchmark oil prices stayed flat over the month, ending July at just over $9/bl. The Brent-WTI spread averaged $2.4/bl in 2021.

Factors which strengthened WTI and Brent oil prices in July:

- **OPEC+ output struggling to grow**

In theory, OPEC+ production should have grown by 3m b/day so far this year, representing quota increases of 0.4m b/day up to June, then 0.6m b/day in July. In reality, the group's production is up by less than 0.5m b/day, with declines from Russia and anaemic growth from many OPEC members contributing to the result. During July, President Biden visited Saudi Arabia, in part to appeal to Crown Prince Bin Salman for Saudi to raise their oil production. The Saudis reiterated their longer-term ambition to raise production capacity to 13m b/day (from around 11-12m b/day today), but were unable to make any promises about shorter-term production. This, we believe, reflects the reality that OPEC spare capacity is particularly tight at present.

- **OECD inventories close to bottom of 10-year range**

OECD total product and crude inventories at the end of June (latest data point) were estimated by the IEA to be 2,676m barrels, up by 6m barrels versus the level reported for April. The inventory level reported for June is around 5% below the 10-year average, and close to the bottom of the 10-year range. Low inventories were a key catalyst for the US and other IEA members in March to announce record releases from Strategic Petroleum Reserves.

Factors which weakened WTI and Brent oil prices in July:

- **High product prices contributing to demand destruction**

With Brent oil prices averaging around $100 per barrel in July, the burden of high oil prices is impacting demand. A price of $100 per barrel translates into the world paying around 4% of GDP for its oil, which is not extreme versus history. However, the impact on the end consumer is being amplified by high product prices (e.g. gasoline; diesel; jet fuel), which have risen faster than crude oil this year. Indeed, refined product prices have translated into an oil price equivalent in the US of over $180/bl, high enough to dent demand. This is showing up in US gasoline, diesel and jet fuel demand, with latest data points down year-on-year.

- **COVID surge in China**

The current surge of COVID in China has impacted forecasts for oil demand. The IEA are currently forecasting Chinese demand for 2022 to average 15.4m b/day, a drop of 0.1m b/day versus 2021. If this forecast proves accurate, it will be the first annual drop in China's consumption of oil this century. Against this, the IEA expect demand to surge in 2023 to 16.3m b/day, as the impacts of COVID are unwound.

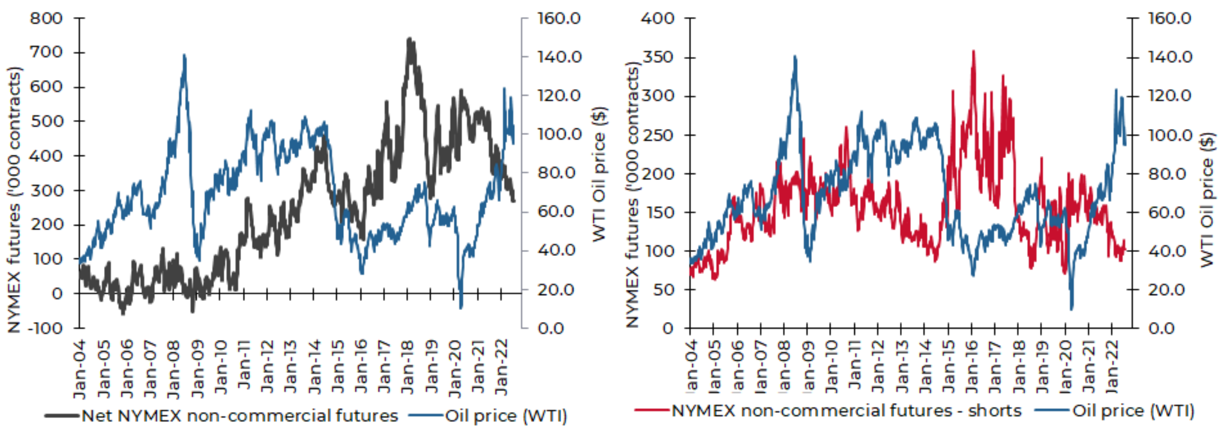
- **Russia supply**

Russian supply has proved more resilient than some commentators were expected, with production in June (latest data) down by only 0.5m b/day versus the start of the year. Supply in April and May had fallen by around 1m b/day from pre-invasion levels, but the bounce since then has been driven by higher domestic consumption and the rerouting of crude exports from Europe to Asia. Despite this resiliency, the IEA are still forecasting a near 3m b/day drop in Russian production by the end of the year, as the EU oil embargo kicks in.

Speculative and investment flows

The New York Mercantile Exchange (NYMEX) net non-commercial crude oil futures open position was 271,000 contracts long at the end of July versus 300,000 contracts long at the end of June. 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 expanded slightly to 104,000 contracts at the end of July versus 96,000 at the end of the previous month.

NYMEX Non-commercial net and short futures contracts: WTI January 2004 – July 2022

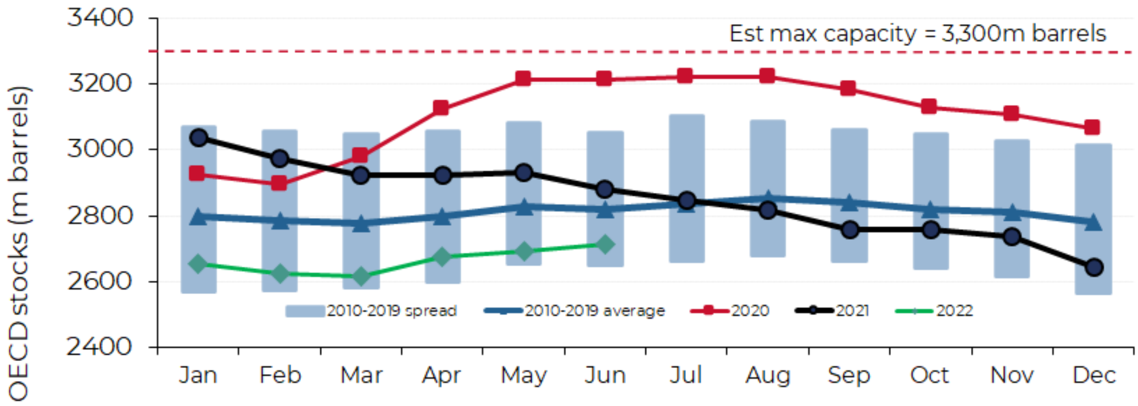


Source: Bloomberg LP/NYMEX/ICE (2022)

OECD stocks

OECD total product and crude inventories at the end of June (latest data point) were estimated by the IEA to be 2,713m barrels, up by 22m barrels versus the level reported for May. This compares to a 10-year average draw for June of 8m barrels, implying that the OECD market was oversupplied. The significant oversupply situation in 2020 pushed OECD inventory levels close to maximum capacity in August 2020 (c3.3bn barrels), with persistent tightening thereafter taking inventories well below normal levels.

OECD total product and crude inventories, monthly, 2004 to 2022



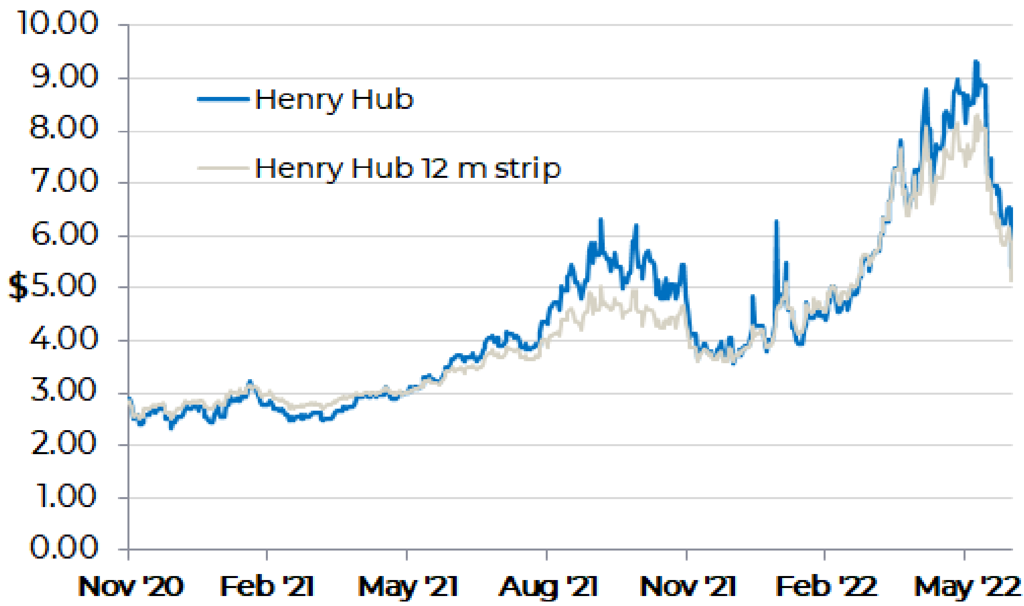
Source: IEA Oil Market Reports (July 2022 and older)

ii) Natural gas market

The US natural gas price (Henry Hub front month) opened July at $5.42/mcf (1,000 cubic feet) and rose sharply over the month to a peak on July 25 of $8.99, before closing at $8.23/mcf. The spot gas price has averaged $6.18/mcf so far in 2022, having averaged $3.70/mcf in 2021, $2.13/mcf in 2020 and $2.53/mcf in 2019.

The 12-month gas strip price (a simple average of settlement prices for the next 12 months' futures prices) also rose over the month, increasing from $5.14/mcf to $6.77/mcf. The strip price has averaged $5.85/mcf so far in 2022, having averaged $3.52 in 2021, $2.54 in 2020 and $2.60 in 2019.

Henry Hub gas spot price and 12m strip ($/Mcf): Jan 2021 to July 2022



Source: Bloomberg LP

Factors which strengthened the US gas price in July included:

- **Higher thermal coal prices**

Thermal coal prices in the north-east of the US rose again in July, as coal supply is pulled into a strong export market. This in turn has raised the switching price for US utilities between natural gas and coal.

- **Lower than normal international gas inventories and stronger international demand**

High gas demand and low inventories in Europe and Asia held international gas prices above $30/mcf during the month. This in turn is maximising demand for exports of LNG from the US. The EIA forecasts that US LNG exports will remain elevated, growing to 13 bcf/day at the end of the year (though note the Freeport LNG disruption mentioned below).

Factors which weakened the US gas price in July included:

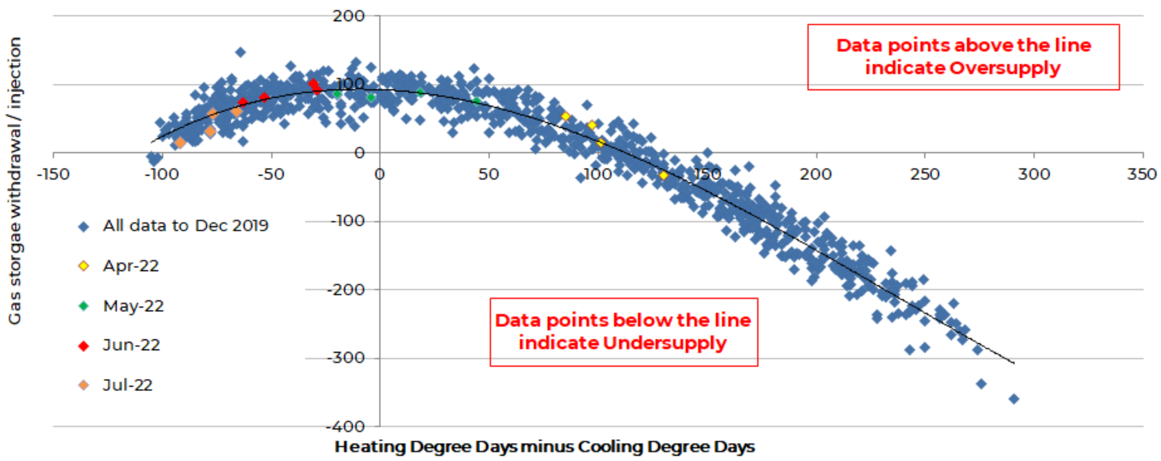
- **Fire at Freeport LNG facility**

The Freeport LNG facility on the US Gulf Coast was shut down due to a fire on June 8. The plant, which is the second largest in the US at just over 2 Bcf/day, is expected to be offline until September, and reduces demand for domestic natural gas supplies. This event has also caused a material spike in international gas prices, since Freeport is normally responsible for supplying around 5% of the world's LNG market.

- **Market undersupplied (ex-weather effects)**

Builds into US natural gas inventories during July were slightly higher than expected for the time of year. Adjusting for the impact of weather, the builds implied that the US gas market was, on average, nearly 0.5 Bcf/day oversupplied.

Weather adjusted US natural gas inventory injections and withdrawals

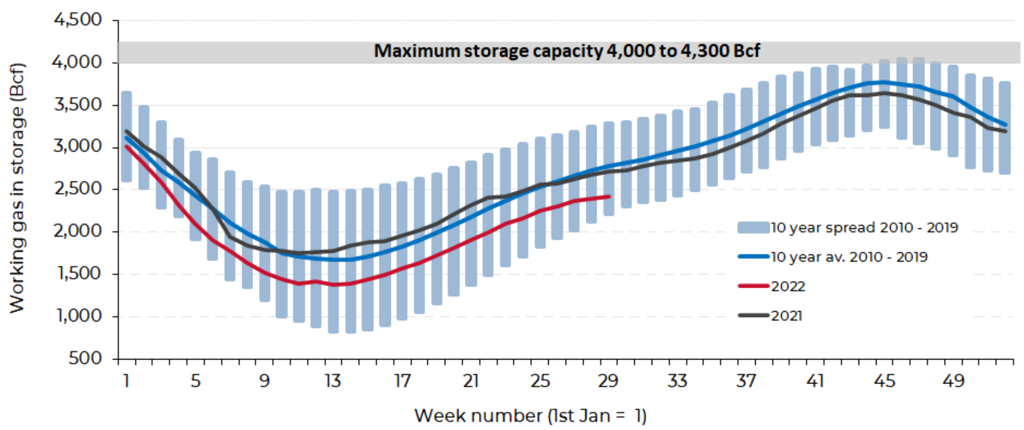


Source: Bloomberg LP; Guinness Global Investors

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 July were reported by the EIA to be 2.4 Tcf. Current gas in storage is around 0.4 Tcf below the 10-year average.

Deviation from 10yr gas storage norm



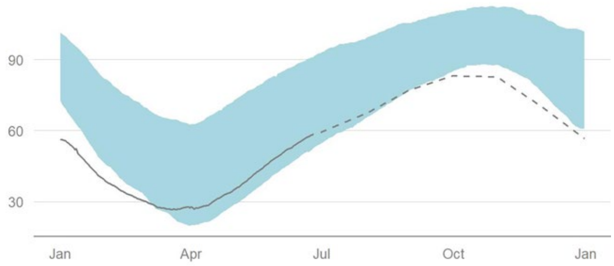
Source: Bloomberg; EIA (July 2022)

2. MANAGER'S COMMENTS

This month, we consider the current state of the European natural gas market and the near-term and long-term options that are available to reduce reliance on Russian natural gas. With limited alternatives, the outlook for the coming winter is very challenging and will have to rely on efficiency and demand destruction if Russian supplies are not forthcoming. Longer-term, an LNG supply response is coming but will not impact the market much before 2027.

In 2021, around one quarter of European energy demand was in the form of natural gas and around 40% of that demand (155 billion cubic metres of gas (bcm)) was sourced from Russia. Europe uses gas predominantly for power generation, industrial activities and heating (both commercial and residential), hence the seasonal demand peak comes in the winter. Inventories of natural gas are used to smooth the seasonal load, but current gas in storage is only at 60bcm (around 15bcm lower than the 5yr average level at this time of the year because of lower Russian imports). With little spare natural gas supply available elsewhere in the world, the outlook for the coming European winter 2022/2023 is challenging.

European natural gas inventories (bcm)



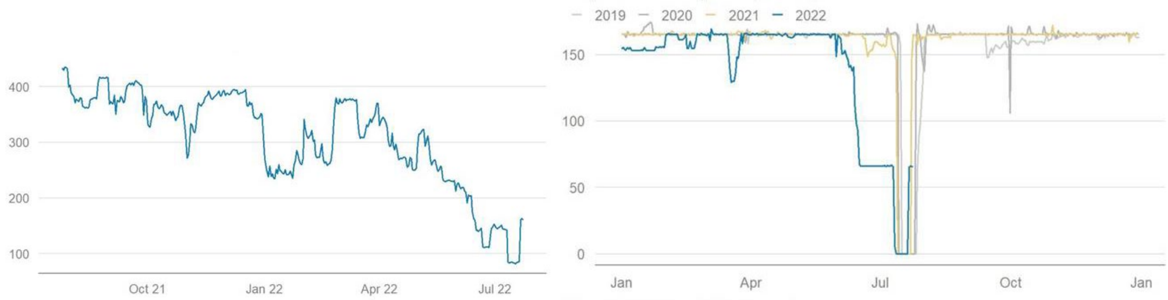
Source: Morgan Stanley. Blue area is five-year average range

The outlook has forced a dramatic policy action from the EU. Its response is centred around the REPowerEU deal, which is designed to increase the resilience of the EU energy system by achieving the following:

- Higher LNG and pipeline gas imports from non-Russian suppliers
- Larger volumes of biomethane and renewable hydrogen production/imports
- Greater emphasis on energy efficiency
- Increasing domestic renewable energy capacity

Most of these actions will take time to have a meaningful effect, so the EU is facing the fact that volatile Russian exports of natural gas could well leave Europe short of gas this winter. As an illustration of the reduced volumes and greater volatility, the key Nordstream-1 gas pipeline that typically carries 160 million cubic metres per day (mcm/d) of Russian natural gas directly to Germany (over 35% of total Russian natural gas exports to the EU) is now running at less than 25% capacity. Nordstream-1 is a critical source of supply: one month of zero flows equates to a total of around 5bcm of natural gas, equivalent to around 10% of current European natural gas inventory levels.

Pipeline flows (mcm/d) from Russia into Europe (left) and via Nordstream-1 into Europe (right)



source: Morgan Stanley (data to 23 July 2022)

Overcoming near-term supply/demand issues

Key factors to help alleviate near-term natural gas market pressures are i) higher LNG and pipeline gas imports from non-Russian suppliers; and ii) greater energy efficiency.

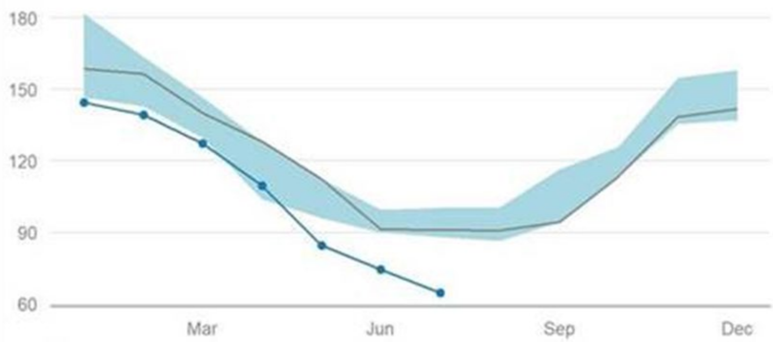
In terms of the first option, we see little relief coming from non-Russian supply sources as there is essentially zero spare gas production capacity in the world:

- In **Europe**, UK production is in slow decline, Dutch authorities are maintaining their plan to shut down the massive Groningen field in 2023 and Norway has exhausted its ability to reallocate gas field maintenance to maximise near-term supplies. Only Algeria, connected to Europe via pipeline to Italy, has been able to offer increased volumes (although this is only an extra 9mcm/day in 2023/2024 on top of current contracted 20mcm/day, equivalent to around 10% of Nordstream-1 volumes).
- The **United States** is the largest LNG exporter in the world and is operating at full available capacity. 71% of its exports in the first half of 2022 went to Europe (230mcm/day), where they represented nearly 50% of EU LNG imports, equivalent to 50% of total Russian gas imports. Near-term LNG supply from the US has been reduced by a fire at Freeport LNG facility (20% of total US capacity), with operations offline until October.
- Reflecting global gas market tightness, **Australia** – the second biggest LNG exporter in the world - is considering plans to limit LNG exports amid fears that the country could face a natural gas supply shortfall in 2023.

With limited near-term supply options, the onus falls on **demand destruction** and increased energy efficiency. During July, the EU set out emergency plans for countries to cut their gas use by 15% over the winter (until March 2023, versus average consumption in the same period during 2016-2021). The "Save Gas for a Safe Winter" proposal is not yet mandatory but could become so if the EU declares a substantial risk of severe gas shortages. These are draconian measures that will impact living standards and economic activity, but even a 15% cut would only save about 45bcm of gas from August-March (less than 30% of EU Russian imports or around three quarters of current gas inventory).

Lower natural gas volumes, higher natural gas prices and initial efficiency steps are starting to have an effect in Germany already. German industrial gas consumption in July 2022 appears to be around 24% lower than the same period in 2021, representing a cut of around 30mcm/day.

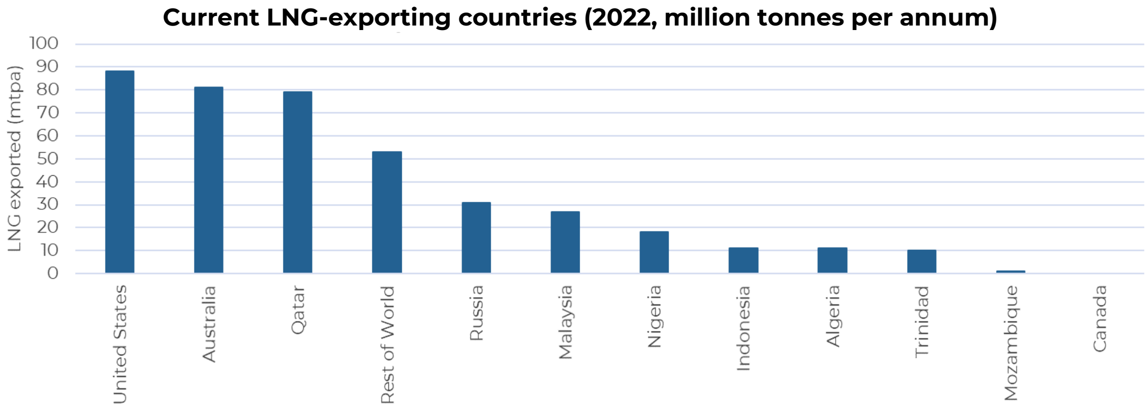
German industrial natural gas consumption (mcm/day)



source: Morgan Stanley. Dark blue is 2022, grey is 2021 and light blue indicates previous five-year range

Longer-term non-Russian supply opportunities

The most likely method for bringing new long-term natural gas supply into Europe is via LNG. The current global LNG market is around 410 million tonnes per annum (mtpa), equivalent to 1,550mcm/day of gas supply or around 3.5x the levels of EU gas imports from Russia, and it is dominated by the United States, Australia and Qatar.



source: Goldman Sachs

High European and Asian gas prices are acting to incentivise the development of new LNG supply projects. We note a step up in new LNG project development announcements since the invasion, including new projects in Qatar and the US, plus the potential for new projects in Tanzania. Indicative economics are that these new LNG export projects will deliver LNG into European markets for between $10/mcf and $14/mcf.

In Qatar, Qatar Energy moved quickly to partner with a number of oil and gas majors to develop the “North Field East” expansion project. The North Field is Qatar’s portion of the world's largest gas field that crosses the maritime border into Iran, where it is called the South Pars field. This latest expansion project is planned to be the single largest project in the history of the LNG industry with 6 individual 8mtpa trains. Partners in the first 4 train development include Shell, TOTAL, Exxon, ConocoPhillips and ENI. The subsequent fifth and sixth trains are part of a second phase which will be called North Field South which is still to be allocated to external investors.

The expansion project is expected to cost nearly $30 billion and will increase Qatar's LNG production capacity from the current 77mtpa to 126mtpa. Despite the rapid announcement of development plan and the brownfield nature of the development, first LNG is not expected until 2027. However, even if the entire six train project were delivered to Europe, the additional 48mtpa of LNG would represent only 40% of the EU’s Russian imports in 2021.

In the US, Venture Global LNG announced financing and a final investment decision for the $13.2bn Plaquemines LNG facility around 20 miles south of New Orleans in Louisiana. Despite lacking full financing, construction had already started in 2021 at the site meaning that first LNG can be expected in 2024. First phase capacity is expected to be around 13.2mtpa (around 12% of EU Russian gas imports). It is interesting to note that this is the first US LNG scheme to see a ‘financial close’ in nearly three years.

Also in recent weeks, Tanzania signed a framework agreement with Equinor and Shell to work towards a 2025 sanctioning of a $30bn LNG export terminal in the country. The first LNG is unlikely before 2030, in our opinion, despite that fact that the gas discoveries were made over ten years ago.

In summary, the coming winter is likely to be bleak for the European gas market and it will ultimately have to rely heavily on maximising other energy sources, plus efficiency and demand destruction. Longer-term, an LNG supply response is underway but it will not impact the market much before 2027. If Russia so choose, the tightness in the European gas market is likely to be sustained for a long while yet.

3. PERFORMANCE Guinness Global Energy Fund

Past performance is not a guide to future returns.

The main index of oil and gas equities, the MSCI World Energy Index (net return), rose by 6.9% in July, while the MSCI World Index (net return) rose by 7.9% in USD.

Within the Fund, July's strongest performers included Enquest, Helix, Devon Energy , Exxon and Chevron while the weakest performers included OMV, Galp, Halliburton, Baker Hughes and Repsol.

Performance (in USD) as at 31.07.2022

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.

Cumulative % returns	**YTD**	**1 year**	**3 years ann.**	**5 years ann.**	**Launch of strategy* ann.** (31.12.98)
Guinness Global Energy Fund (Class Y, 0.99% OCF)	18.3%	37.8%	4.2%	2.1%	8.2%
MSCI World Energy NR Index	32.5%	49.5%	8.9%	6.0%	6.2%

Calendar year % returns	**2021**	**2020**	**2019**	**2018**	**2017**	**2016**	**2015**
Guinness Global Energy Fund (Class Y, 0.99% OCF)	44.5%	-34.7%	9.8%	-19.7%	-1.3%	27.9%	-27.6%
MSCI World Energy NR Index	40.1%	-31.5%	11.4%	-15.8%	5.0%	26.6%	-22.8%
	2014	**2013**	**2012**	**2011**	**2010**	**2009**	**2008***
Guinness Global Energy Fund (Class Y, 0.99% OCF)	-19.1%	24.4%	3.0%	-13.7%	15.3%	61.8%	-44.8%
MSCI World Energy NR Index	-11.6%	18.1%	1.9%	0.2%	11.9%	26.2%	-32.8%

Source: FE fundinfo, Guinness Global Investors and Bloomberg, bid to bid, gross income reinvested, in US dollars

Calculation by Guinness Global Investors, *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 December 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. Returns for share classes with a different OCF will vary accordingly.

Investors should note that fees and expenses are charged to the capital of the Fund. This reduces the return on your investment by an amount equivalent to the Ongoing Charges Figure (OCF). The fund performance shown has been reduced by the current OCF of 0.99% per annum. Returns for share classes with different OCFs will vary accordingly. Performance returns do not reflect any initial charge; any such charge will also reduce the return.

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 0.96% 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 wwww.guinnessgi.com Please contact info@guinnessgi.com or +44 (0) 20 7222 5703 for more details.

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.guinnessgi.com.

4. PORTFOLIO Guinness Global Energy Fund

Buys/Sells

In July there were no buys or sells of full positions, but the portfolio was actively rebalanced.

Sector Breakdown

The following table shows the asset allocation of the Fund at **July 31 2022**.

Asset allocation as %NAV	Current	*Change*	Last year end	Previous year ends				
	Jul-22		Dec-21	Dec-20	Dec-19	Dec-18	Dec-17	Dec-16
Oil & Gas	**97.3%**	***0.4%***	**96.9%**	**94.8%**	**98.3%**	**96.7%**	**98.4%**	**96.7%**
Integrated	54.4%	*-3.3%*	57.7%	56.3%	51.1%	46.4%	42.9%	46.4%
Exploration & Production	24.1%	*0.4%*	23.7%	22.2%	29.6%	35.8%	36.9%	35.8%
Drilling	0.0%	*0.0%*	0.0%	0.0%	0.1%	2.2%	1.9%	2.2%
Equipment & Services	7.2%	*3.1%*	4.0%	4.6%	9.6%	8.6%	9.5%	8.6%
Storage & Transportation	5.7%	*1.4%*	4.3%	4.4%	4.0%	0.0%	3.5%	0.0%
Refining & Marketing	5.9%	*-1.3%*	7.2%	7.3%	3.8%	3.7%	3.7%	3.7%
Solar	0.9%	*-0.1%*	1.0%	1.8%	0.7%	0.9%	1.4%	0.9%
Coal & Consumable Fuels	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%
Cash	1.8%	*-0.3%*	2.1%	3.3%	1.1%	2.4%	0.2%	2.4%

Source: Guinness Global Investors. Basis: Global Industry Classification Standard (GICS)

The Fund at end of July 2022 was on a price to earnings ratio (P/E) for 2021/2022 of 13.1x/5.9x versus the MSCI World Index at 16.2x/15.2x as set out in the following table:

As at 31 July 2022	P/E		
	2021	2022E	2023E
Guinness Global Energy Fund	13.1x	5.9x	6.6x
MSCI World Index	18.3x	16.2x	15.2x
Fund Premium/(Discount)	*-28%*	*-64%*	*-57%*

Source: Bloomberg; Guinness Global Investors

Portfolio holdings

Our integrated and similar stock exposure (c.54%) 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 July 31 2022 the median P/E ratio of this group was 8.7x 2021 earnings. We also have three Canadian integrated holdings, Suncor, Cenovus and Imperial Oil. All three 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, Diamondback, 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 two emerging market stocks, Petrochina and Sinopec, in the portfolio and in total represent around 3% of the portfolio.

The portfolio contains two midstream holdings, Enbridge and Kinder Morgan, two of 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 both companies are well placed to execute their pipeline expansion plans.

We have reasonable exposure to oil service stocks, which comprise around 7% 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 a recovery in refining margins.

Portfolio at June 30 2022 (for compliance reasons disclosed one month in arrears)

Guinness Global Energy Fund (30 June 2022)			P/E			EV/EBITDA		
Stock	**ISIN**	**% of NAV**	**2020**	**2021E**	**2022E**	**2020**	**2021E**	**2022E**
Integrated Oil & Gas								
Exxon Mobil Corp	US30231G1022	5.2%	n/a	16.3x	8.3x	20.0x	7.4x	4.4x
Chevron Corp	US1667641005	4.9%	n/a	16.9x	8.6x	17.2x	7.0x	4.5x
Shell PLC	GB00BP6MXD8	4.8%	41.6x	11.1x	5.3x	7.2x	4.5x	3.0x
Total SA	FR0000120271	5.3%	36.6x	8.1x	4.3x	8.9x	4.2x	2.6x
BP PLC	GB0007980591	4.5%	n/a	7.6x	4.4x	10.8x	3.9x	2.9x
Equinor ASA	NO0010096985	4.4%	62.4x	11.3x	5.9x	5.8x	2.4x	1.4x
ENI SpA	IT0003132476	2.6%	n/a	8.7x	3.7x	5.2x	3.2x	2.2x
Repsol SA	ES0173516115	4.2%	58.2x	8.6x	4.2x	6.2x	3.8x	2.5x
Galp Energia SGPS SA	PTGAL0AM000	3.3%	n/a	18.2x	8.8x	6.9x	5.0x	3.4x
OMV AG	AT0000743059	3.0%	18.6x	4.9x	3.7x	6.4x	3.1x	2.6x
		42.3%						
Integrated / Oil & Gas E&P - Canada								
Suncor Energy Inc	CA8672241079	3.6%	n/a	16.9x	5.0x	16.3x	5.8x	3.3x
Canadian Natural Resources Ltd	CA1363851017	3.4%	n/a	11.4x	5.6x	15.8x	5.9x	3.6x
Cenovus Energy Inc	CA15135U1093	3.6%	n/a	24.6x	6.5x	n/a	6.5x	3.5x
Imperial Oil Ltd	CA4530384086	3.6%	n/a	16.1x	5.8x	45.0x	7.8x	4.3x
		14.2%						
Integrated Oil & Gas - Emerging market								
PetroChina Co Ltd	CNE1000003W	1.6%	29.8x	6.0x	5.1x	4.6x	3.5x	3.2x
		1.6%						
Oil & Gas E&P								
ConocoPhillips	US20825C1045	4.1%	n/a	14.9x	6.0x	22.5x	6.0x	3.3x
EOG Resources Inc	US26875P1012	3.5%	100.8x	12.7x	6.7x	13.4x	6.0x	3.9x
Diamondback Energy Co	US25278X1090	3.5%	40.4x	11.0x	4.8x	12.9x	6.6x	3.6x
Pioneer Natural Resources Co	US7237871071	3.6%	142.8x	17.4x	6.7x	25.3x	8.4x	4.1x
Devon Energy Corp	US25179M1036	3.7%	n/a	16.3x	6.3x	25.5x	7.2x	3.9x
		18.4%						
International E&Ps								
Pharos Energy PLC	GB00B572ZV91	0.1%	n/a	n/a	4.4x	1.4x	1.6x	0.9x
		0.1%						
Midstream								
Kinder Morgan Inc	US49456B1017	2.4%	31.2x	13.2x	14.5x	10.1x	8.8x	9.5x
Enbridge Inc	CA29250N1050	3.1%	21.9x	19.2x	18.1x	15.3x	14.6x	13.5x
		5.5%						
Equipment & Services								
Schlumberger Ltd	AN8068571086	3.3%	55.6x	28.2x	19.2x	14.7x	12.6x	10.4x
Halliburton Co	US4062161017	1.7%	50.5x	29.4x	16.6x	14.5x	12.8x	9.3x
Baker Hughes a GE Co	US05722G1004	1.7%	104.2x	43.9x	25.1x	15.1x	12.9x	10.6x
Helix Energy Solutions Group Inc	US42330P1075	0.5%	n/a	n/a	n/a	3.5x	5.4x	7.5x
		7.3%						
Oil & Gas Refining & Marketing								
China Petroleum & Chemical Corp	CNE1000002Q2	1.1%	10.0x	4.8x	5.2x	5.6x	3.5x	3.6x
Valero Energy Corp	US91913Y1001	4.6%	n/a	60.6x	6.5x	53.5x	13.2x	4.7x
		5.7%						
Research Portfolio								
Deltic Energy PLC	GB00B6SYKF01	0.2%	n/a	n/a	n/a	n/a	n/a	n/a
EnQuest PLC	GB00B635TG28	0.4%	n/a	4.3x	1.4x	2.7x	1.9x	1.4x
Reabold Resources PLC	GB00B95L0551	0.1%	n/a	n/a	n/a	n/a	n/a	n/a
Sunpower Corp	US8676524064	0.7%	n/a	82.8x	59.7x	91.8x	41.7x	29.8x
Maxeon Solar Technologies Ltd	SGXZ25336314	0.0%	n/a	n/a	n/a	n/a	n/a	n/a
Diversified Energy Company	GB00BYX7JT74	0.4%	5.7x	27.7x	8.5x	7.1x	6.0x	4.5x
		1.8%						
Cash	Cash	3.2%						
Portfolio		**100.0%**	**77.9x**	**13.0x**	**6.3x**	**11.0x**	**5.5x**	**3.6x**

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	2021	2022E	2023E
								IEA	*IEA*
World Demand	***95.3***	***96.4***	***98.2***	***99.5***	***100.7***	***91.7***	***97.5***	***99.2***	***101.3***
Non-OPEC supply (inc NGLs)	*60.3*	*59.8*	*60.8*	*63.5*	*65.6*	*63.0*	*63.7*	*65.5*	*65.6*
OPEC NGLs	*5.2*	*5.3*	*5.4*	*5.5*	*5.4*	*5.1*	*5.1*	*5.4*	*5.5*
Non-OPEC supply plus OPEC NGLs	**65.5**	**65.1**	**66.2**	**69.0**	**71.0**	**68.1**	**68.8**	**70.9**	**71.1**
Call on OPEC (crude oil)	**29.8**	**31.3**	**32.0**	**30.5**	**29.7**	**23.6**	**28.7**	**28.3**	**30.2**
Congo supply adjustment	0.3	0.3	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	0.2	0.2
Eq Guinea supply adjustment	0.1	0.1	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**	**29.9**	**29.1**	**23.0**	**28.1**	**27.7**	**29.6**

Source: Bloomberg; IEA; Guinness Global Investors

Global oil demand in 2019 was 13m b/day higher than the pre-financial crisis (2007) peak. 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. Demand recovered in 2021 by around 5.7m b/day, leaving overall consumption still around 3m b/day below the 2019 peak.

OPEC

The last few 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 late 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 included a cut in production from Russia (a non-OPEC country), creating for the first time the concept of an OPEC+ group.

OPEC-10 oil production to June 2022

('000 b/day)	31-Dec-19	31-May-22	30-Jun-22	Current vs Dec 2019	Current vs last month
Saudi	9,730	10,430	**10,450**	720	20
Iran	2,080	2,580	**2,550**	470	-30
Iraq	4,610	4,430	**4,420**	-190	-10
UAE	3,040	3,100	**3,190**	150	90
Kuwait	2,710	2,690	**2,640**	-70	-50
Nigeria	1,820	1,300	**1,200**	-620	-100
Venezuela	730	680	**710**	-20	30
Angola	1,390	1,160	**1,200**	-190	40
Libya	1,110	760	**670**	-440	-90
Algeria	1,010	1,020	**1,020**	10	0
OPEC-10	**28,230**	**28,150**	**28,050**	**-180**	**-100**

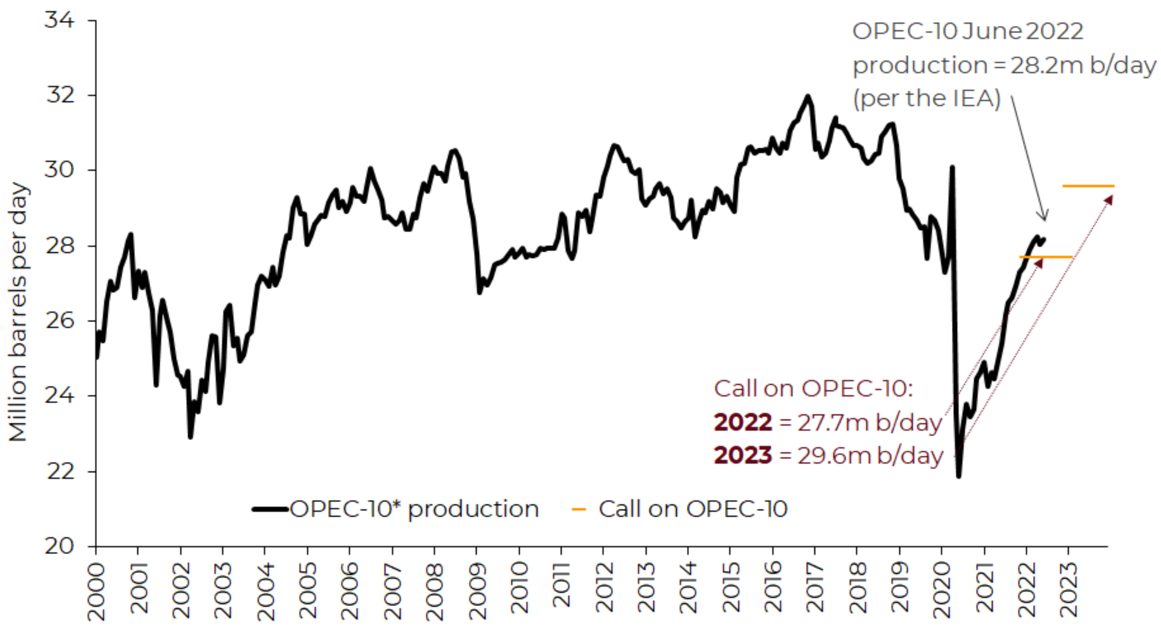
Source: Bloomberg; Guinness Global Investors

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.

In July 2021, the OPEC+ group agreed to taper their quota cuts at 0.4m b/day until September 2022, whilst still meeting monthly to ratify each production increase in light of the prevailing conditions. The agreement gave us confidence that OPEC was looking to do 'what it takes' to keep the market in balance, despite extreme challenges.

OPEC-10 apparent production vs call on OPEC 2000 – 2023



Source: IEA Oil Market Report (July 2022 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.$75/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 and Russia crises have created particularly challenging conditions, adding to oil price volatility. Longer-term, we believe that Saudi seek a 'good' oil price, one that satisfies their fiscal needs. 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

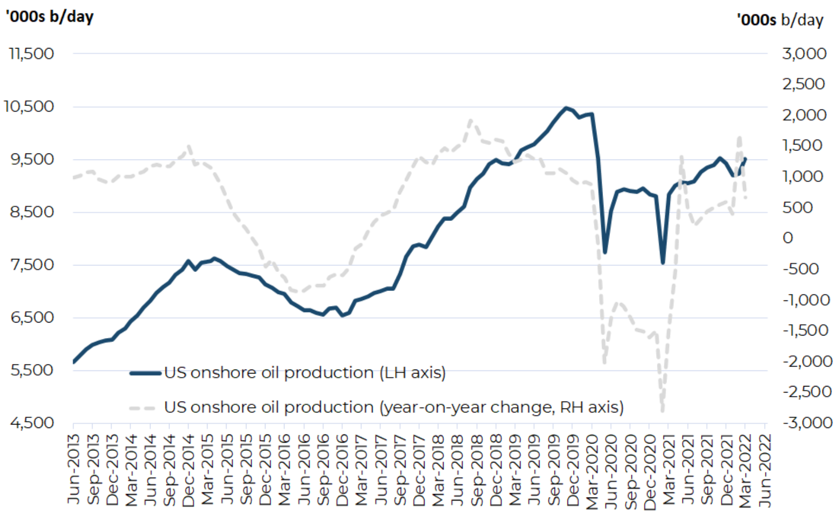
Nothing in the market in recent years has changed our view that OPEC can put a floor under the price – as they did in 2020, 2018, 2016, 2008, 2006, 2001 and 1998.

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.

US onshore oil production



Source: EIA; Guinness Global Investors

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. Since 2019, we have seen increased shareholder pressure applied to US E&P companies to improve their capital discipline and to cut their reinvestment rates.

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 reducing capital spending further as they attempted to live within their cashflows. Despite a stronger oil price since then, the overall reduction in activity caused average US shale supply to decline in 2021. Production growth is returning in 2022, albeit slower than the previous cycle, as the Russia/Ukraine crisis creates greater space again for US shale barrels in the world market.

Non-OPEC supply growth outside the US has been sustained in recent years, despite lower oil prices, with projects that were sanctioned before 2014 (when oil was $100/bl+) continuing to come onstream. However, with a lack of major project additions post 2020, new supply is only strong enough to offset the decline profiles of existing production, causing overall supply to stagnate.

Demand looking forward

The IEA estimate that 2022 oil demand will rise by around 1.7m b/day to 99.2m b/day, still around 1.5m b/day below the 2019 pre-COVID peak. The spread of the COVID virus globally caused major restrictions to the movement of people, which has now largely reversed, but high prices and slower economic growth are curtailing demand growth in certain sectors.

Post the COVID demand recovery and assuming typical economic growth, we expect the world to settle back into oil demand growth of plus or minus 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.

The trajectory of global oil demand over the next few years will be a function of global GDP, the pace of the 'consumerisation' of developing economies, the development of alternative fuels and price. At a $75/bl oil price, the world oil bill as a percentage of GDP is around 3% and this will still be a stimulant of further demand growth. If oil prices persist in a higher range (say around $100/bbl, representing 4% 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 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 6.1m in 2021, up from 3.1m in 2020. We expect to see strong EV sales growth again in 2022, up to around 9m, or 10% 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 2022 versus recent history.

Average WTI & Brent yearly prices, and changes

Oil price (inflation adjusted)																*Est*
12 month MAV	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
WTI	82	104	68	84	99	94	98	93	49	45	51	65	57	40	68	92
Brent	82	103	67	84	115	112	108	99	52	45	54	72	60	42	70	95
Brent/WTI (12m MAV)	**82**	**104**	**68**	**84**	**107**	**103**	**103**	**96**	**51**	**45**	**53**	**68**	**59**	**41**	**69**	**94**
Brent/WTI y-on-y change	9%	26%	-35%	24%	27%	-4%	0%	-7%	-47%	-11%	17%	30%	-14%	-30%	68%	36%
Brent/WTI (5yr MAV)	61	75	79	82	89	93	93	99	92	80	69	63	55	53	58	66

Source: Guinness Global Investors, Bloomberg

We believe that Saudi's long-term objective remains to maintain a 'good' oil price, something north of $75/bl. The world oil bill at around $75/bl represents 3.0% of 2021 Global GDP, under the average of the 1970 – 2015 period (3.4%).

ii) 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.

US natural gas demand

Bcf/day	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022E
US natural gas demand:											
Residential/commercial	19.2	22.4	23.4	21.4	20.5	20.9	23.4	23.5	21.3	22.2	21.9
Power generation	24.9	22.3	22.3	26.5	27.3	25.3	29.0	30.9	31.7	30.3	30.5
Industrial	19.7	20.3	20.9	20.6	21.1	21.6	23.0	23.0	22.6	23.0	23.1
Pipeline exports (Mexico)	1.8	1.9	1.9	2.7	3.8	4.0	4.6	5.1	5.4	6.1	6.3
LNG exports	-	-	-	0.1	1.0	2.6	3.4	5.7	7.3	10.3	12.6
Pipeline/plant/other	6.1	6.7	6.3	6.5	6.4	6.5	7.1	7.6	7.7	7.8	8.1
Total demand	**71.7**	**73.6**	**74.8**	**77.8**	**80.1**	**80.9**	**90.5**	**95.8**	**96.0**	**99.7**	**102.5**
Demand growth	**3.1**	**1.9**	**1.2**	**3.0**	**2.3**	**0.8**	**9.6**	**5.3**	**0.2**	**3.7**	**2.8**

Source: Guinness estimates; GS (August 2022)

Industrial demand (of which around 35% comes from petrochemicals) tends to trend up and down depending on the strength of the economy 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 2021, 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.

Total gas demand in 2021 (including Mexican and LNG exports) was around 99.7 Bcf/day, up by 3.7 Bcf/day versus 2020 and 11 Bcf/day (12%) higher than the 5-year average. The biggest contributors to the growth in demand in 2020 were residential/commercial and LNG exports (opening of new export terminals). Power generation for gas was lower, however.

We expect US demand in 2022, assuming prices average around $5-6/mcf, to be up by around 3 Bcf/day. 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, holding the gas price lower.

The supply side fundamentals for natural gas in the US are driven by three main moving parts: onshore and offshore domestic production, pipeline imports of gas from Canada and LNG imports. Of these, onshore supply is the biggest component, making up over 90% of total supply.

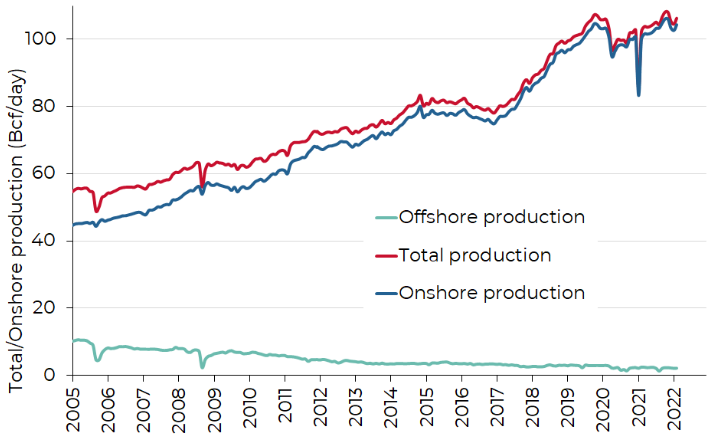
US natural gas supply

Bcf/day	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022E
US natural gas supply:											
US (onshore & offshore)	65.7	66.3	70.9	74.2	73.4	73.6	84.0	92.3	9	93.0	95.8
Net imports (Canada)	5.4	5.0	4.9	4.9	5.5	5.8	5.4	4.7	4.4	5.3	5.6
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**	**96.5**	**98.3**	**101.5**
Supply growth	**2.4**	**-**	**4.4**	**3.3**	**- 0.3**	**0.4**	**9.8**	**7.6**	**- 0.6**	**1.8**	**3.2**
(Supply)/demand balance	**- 0.2**	**1.7**	**- 1.5**	**- 1.8**	**0.8**	**1.2**	**1.0**	**- 1.3**	**- 0.5**	**1.4**	**1.0**

Source: EIA; GS; 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 157 at the end of July 2022. 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.

US natural gross gas production 2005 – 2022 (Lower 48 States)



Source: EIA 914 data (July 2022 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.

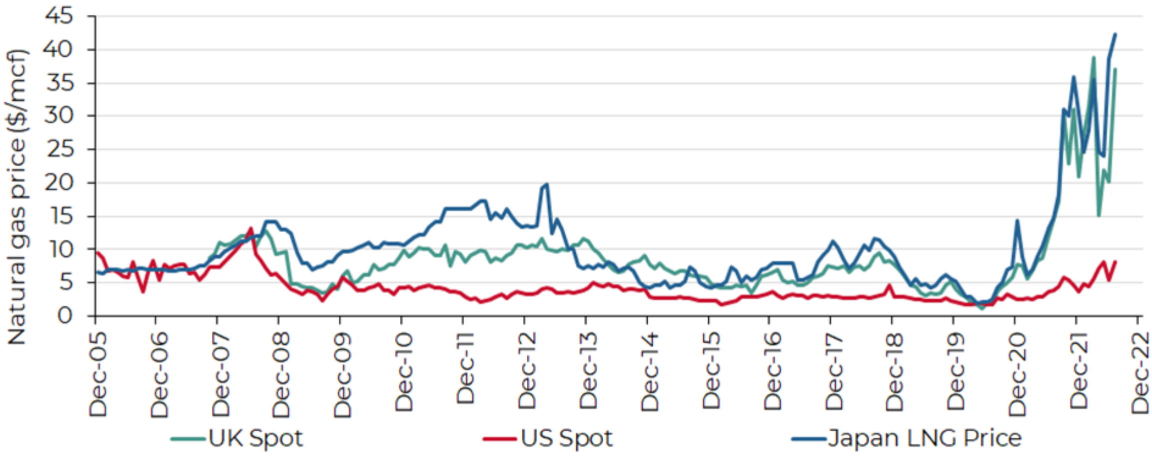
Associated gas production declined in 2021 with the fall of shale oil production, but will rise again in 2022 as shale oil grows again. Generally, we expect to see rates of around 2-3 Bcf/day of associated gas per 1m b/day of oil production growth. The Marcellus/Utica region, which includes the largest producing gas field in the US and the surrounding region, reached production of around 32 Bcf/day in 2021. Moderate growth is likely in 2022.

Overall, if the price averages in the $5-$6/mcf range, we expect a rise in average onshore gas supply in 2022, up by around 2-3 Bcf/day versus 2021.

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 significant premium to the US gas price (c.$25-35/mcf versus c.$6-8/mcf). Asian spot LNG prices have also been extraordinarily strong, averaging over $10/mcf in 2021 and up over $40/mcf on a spot basis at the end of July. There have been many factors at play, in particular the strong post-COVID demand recovery, and a shortage of Russian imports into Europe. The implied economics for US LNG exports into Europe and Asia are attractive assuming international prices are at least $5/mcf higher than Henry Hub.

International gas prices to July 2022

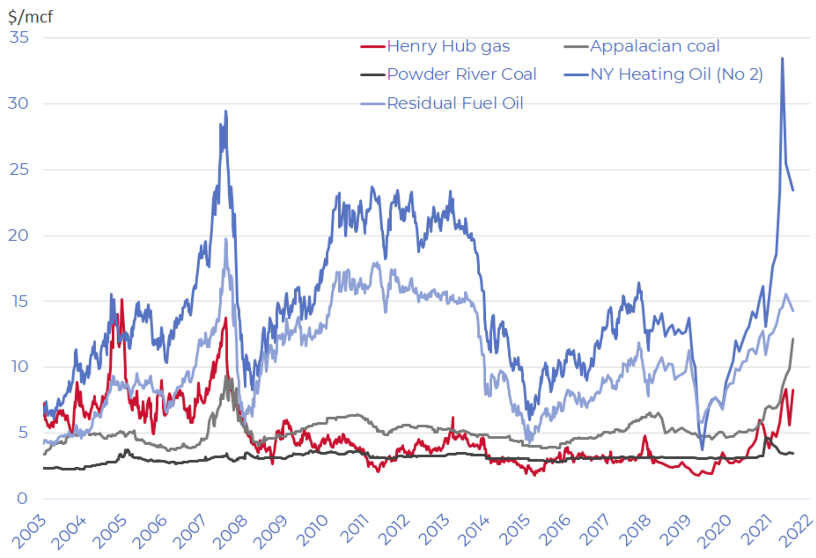


Source: Bloomberg; Guinness Global Investors (July 2022)

Relationship with oil and coal

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.

Natural gas versus substitutes (fuel oil and coal) - Henry Hub vs residual fuel oil, heating oil, Sandy Barge (adjusted) and Powder River coal (adjusted)



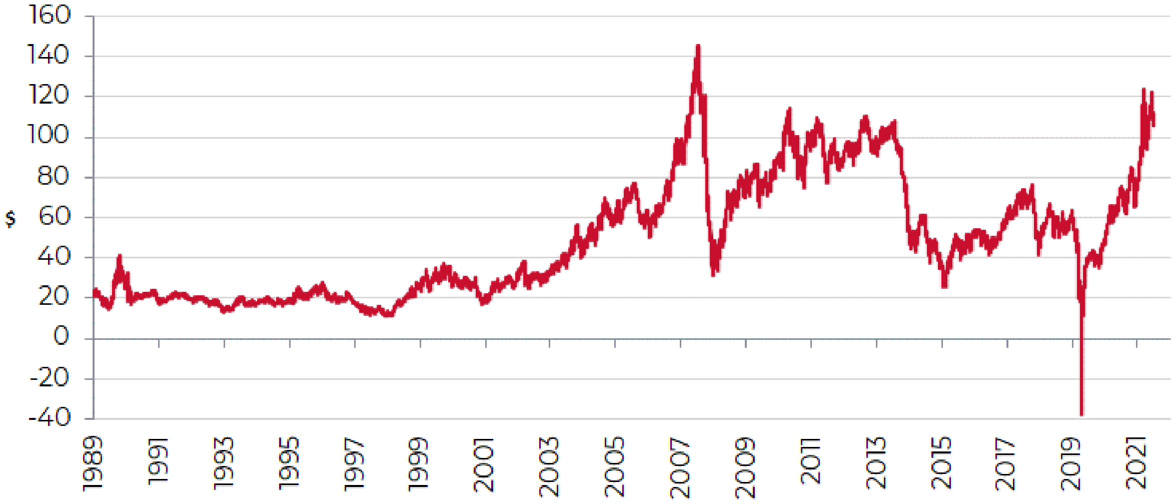
Source: Bloomberg; Guinness Global Investors (July 2022)

Conclusions about US natural gas

The US natural gas price was held back in the 2010s 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 $3.71/mcf in 2021, up from $2.13/mcf in 2020, and we suspect that the (full cycle) marginal cost of supply is now around $4-5/mcf. More controlled growth in associated gas supply over the next couple of years should allow gas prices to stay closer to the full-cycle cost level.

6. APPENDIX Oil and gas markets historical context

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 four 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.

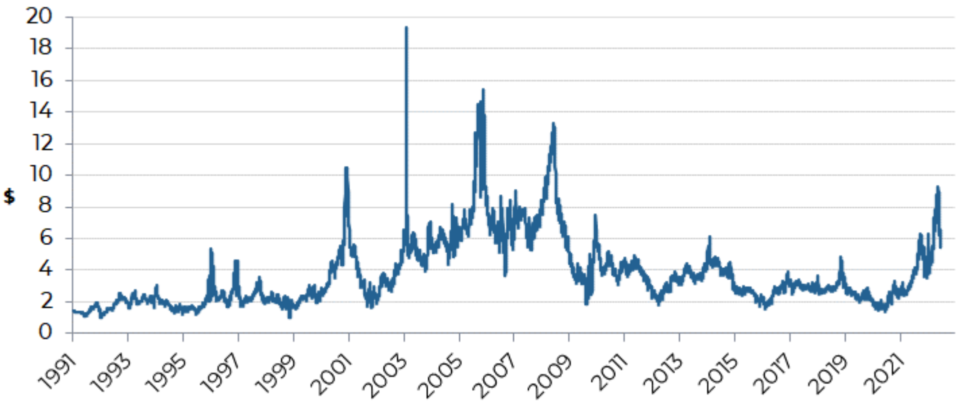
   Continued expectations of a supply crunch by the end of the decade, coupled with increased speculative activity in oil markets, contributed to the oil price surging past $90 in the final months of 2007 and as high as $147 by the middle of 2008. This spike was brought to an abrupt end by the collapse 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) **2014-2020:** 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.

4) **2021-:** Underinvestment in new oil capacity in the 2015-2020 period catalysed the start of a new cycle in 2021, pushing prices above $75/bl.

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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