THE GUINNESS GLOBAL ENERGY REPORT

Developments and trends for investors in the global energy sector | August 2018

GUINNESS GLOBAL ENERGY FUND

Fund size: $303m (31.7.2018)

The Guinness Global Energy Fund invests in listed equities of companies engaged in the exploration, production and distribution of oil, gas and other energy sources. We believe that over the next twenty years the combined effects of population growth, developing world industrialisation and diminishing fossil fuel supplies will force energy prices higher and generate growing profits for energy companies.

The Fund is run by Will Riley, Jonathan Waghorn and Tim Guinness. The investment philosophy, methodology and style which characterise the Guinness approach have been applied to the management of energy equity portfolios since 1998.

HIGHLIGHTS FOR JULY

OIL

Brent and WTI down; OPEC supply increase starts to emerge

Brent and WTI down over 5% over the month; Brent fell from $79/bl to $73/bl; WTI fell from $74/bl to $69/bl. Saudi exports are starting rise in response to weaker supply elsewhere in the group; fears of global protectionism weighed on forecasts for oil demand growth; offset by weakest growth in US onshore oil supply since January.

NATURAL GAS

US gas prices slight lower; European/Asian prices staying strong

Henry Hub prices were slightly lower on the month, falling from $2.92/mcf to $2.83/mcf. Inventories are at close to 10 year low levels but supply is responding (up 10 Bcf/day yoy). European gas prices flat at around $7/mcf; Asian LNG imports at $9/mcf.

EQUITIES

Energy underperforms the broad market

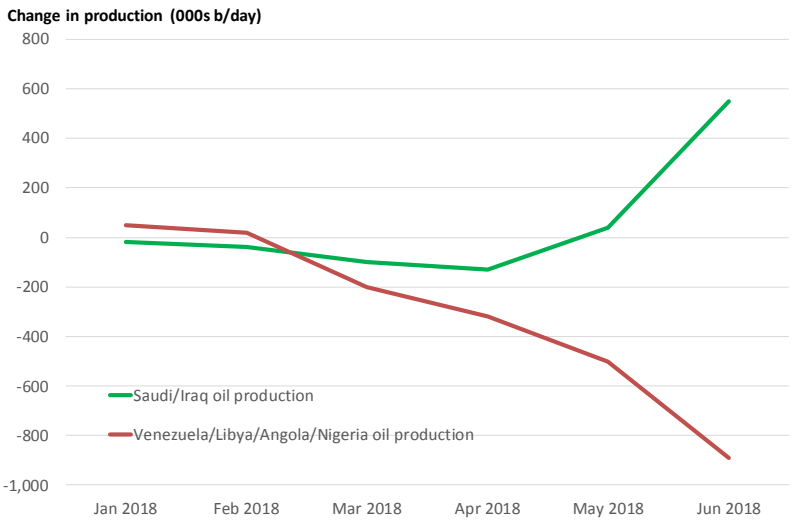
The MSCI World Energy Index rose in July by 1.5%, underperforming the MSCI World Index which rose by 3.2% over the month (all in US dollar terms). For the year to July 31 2018, the MSCI World Energy Index is ahead of the MSCI World by 4.5%.

CHART OF THE MONTH

Production rise from core OPEC started before June 22 meeting

At their scheduled meeting on June 22 2018, OPEC agreed to increase oil production up to existing quotas, in an effort to keep the market from becoming too tight. IEA production numbers for June show that certain 'tier 1' OPEC members (Saudi, Iraq) had already decided in the run up to the meeting that higher production was necessary, given the severity of declines in 'tier 2' OPEC (Venezuela, Libya, Nigeria, Angola). The wildcard for OPEC production for the remainder of 2018 is Iranian oil exports, expected to drop sharply in Q4 thanks to US sanctions.

Saudi/Iraq response to outages elsewhere in OPEC



Source: Bloomberg, Guinness Asset Management

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GUINNESS ASSET MANAGEMENT

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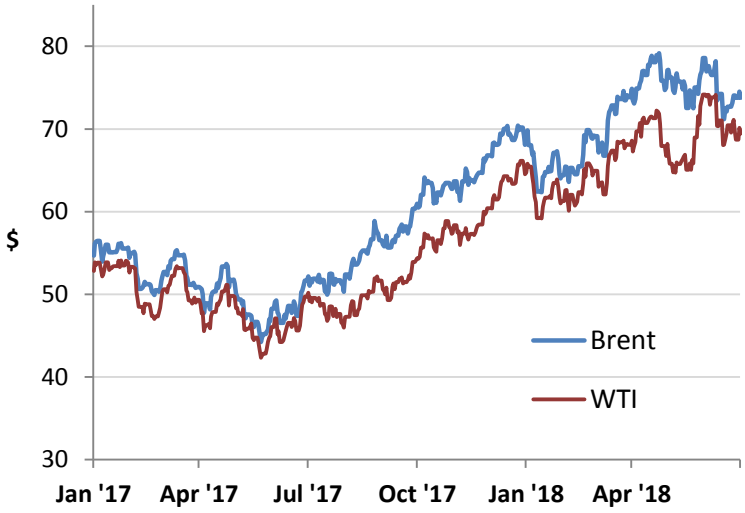
1. JULY IN REVIEW

i) Oil market

Figure 1: Oil price (WTI and Brent $/barrel) 18 months January 31 2017 to July 31 2018



Source: Bloomberg LP

The West Texas Intermediate (WTI) oil price started July at $74.1/bl and moved gradually lower over the first half of the month to a low on July 16 of $68.1/bl. The price then recovered slightly to end the month at $68.8/bl. WTI has averaged $66.3/bl so far in 2018, having averaged $51 in 2017, $43.4 in 2016, $48.7 in 2015 and $93.1 in 2014.

Brent oil traded in a similar shape, opening at $78.6/bl, dipping in the middle of the month to just over $71/bl, then recovering to close July at $73.1/bl. Brent has averaged $71.3/bl so far in 2018. The gap between the WTI and Brent benchmark oil prices stayed roughly flat versus the end of June, ending July at just over $4/bl. The Brent-WTI spread had widened in May to over $10/bl.

Factors which strengthened WTI and Brent oil prices in July:

- **Further weakening of production in 'tier 2' OPEC countries**
  June production numbers published in July by the IEA showed further declines in Venezuela and Libya. Venezuelan production was down to 1.3m b/day, falling from 2.0m b/day at the same point last year, whilst Libyan production has fallen to 0.7m b/day, down from 1.0m b/day at the start of the year. While upstream production in Venezuela has been poor as a result of low reinvestment (the country's rig count has dropped to 26 rigs, down from the peak of 77 rigs in August 2014) there are also increased issues revolving around the inability to export crude oil. Meanwhile, civil unrest in Libya caused the the closure of the Es Sider, Ras

Lanuf, Hariga & Zueitina ports. The issues in Libya are likely to be more temporary than those in Venezuela, nevertheless the lost production is having to be compensated for by other OPEC members.

- **Small increase in US onshore oil supply**
  At the start of August, the EIA reported that US onshore production increased by 45k b/day during May 2018. This represents the slowest pace of growth for 4 months, puts year over year growth for the US onshore system at around 1.4m b/day. Infrastructure constraints in the Permian basin have caused the oil directed rigcount to plateau, which will dampen the rate of production growth in the second half of 2018 and 2019.

Factors which weakened WTI and Brent oil prices in July:

- **Concerns around the effect of protectionism on global oil demand**
  On July 10, the Trump Administration released a list of roughly $200bn worth of imports from China that it proposes to subject to a 10% tariff. The proposal represented a major escalation from the previous round of tariffs, which applied to around $16bn of Chinese imports into the US. July also saw an escalation of protectionist talk between the US and EU, all of which raised concerns that the global economy could slow, and with it global oil demand growth could slow. The IEA currently forecast 1.4m b/day of oil demand growth in 2018, and the same in 2019. Crude and product inventory movements suggest to us that actual demand growth is currently running higher than this.

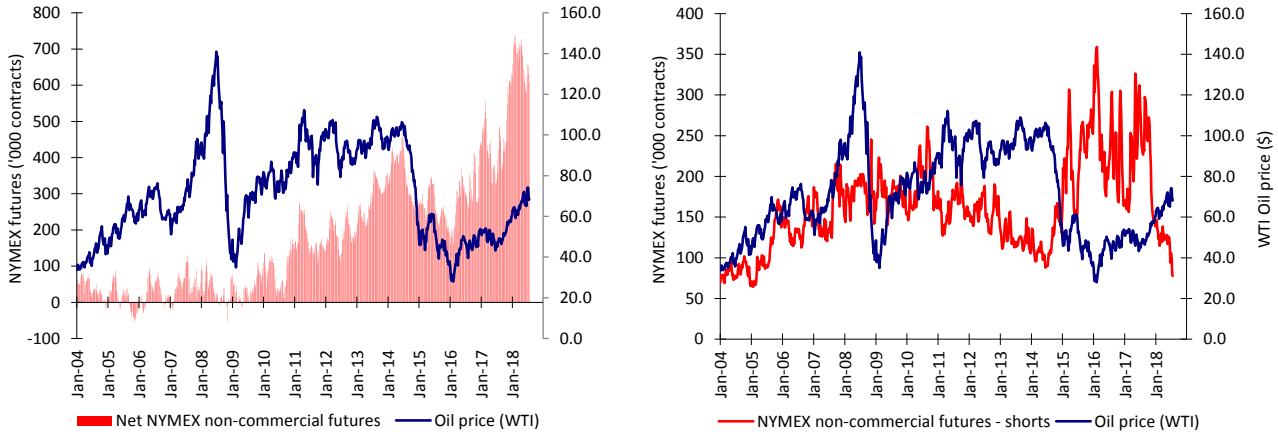
- **Fall in crude oil speculative positioning**
  The New York Mercantile Exchange (NYMEX) net non-commercial crude oil futures open position (WTI) fell in July, declining from 657,000 contracts long to around 610,000 contracts at the end of the month. The decline coincided with weakness in spot prices in the middle of July. The net long position peaked in February 2018 at around 739,000 contracts, so has declined by around 17%, but remains elevated versus history. We consider that sharp moves in speculative crude positioning contributes to short term volatility in the oil price, but have limited impact on longer term price levels.

- **Increasing OPEC oil exports**
  Seaborne oil exports from Saudi, Kuwait and UAE appear to have increased by around 1m b/day in June (the latest data available), indicating that OPEC were already responding to the tightness in the market ahead of their June 22 meeting in Vienna. The IEA reported Saudi production to have increased from 10.0m b/day in May to 10.5m b/day, after sharp falls from Venezuela and Libya threatened a shortage of supply.

Speculative and investment flows

The New York Mercantile Exchange (NYMEX) net non-commercial crude oil futures open position (WTI) decreased in July, ending the month at 610,000 contracts long versus 657,000 contracts long at the end of June. Typically there is a positive correlation between the movement in net position and movement in the oil price. The gross short position reduced from 106,000 contracts to 78,000 contracts. This short position is now at relatively low level versus those seen in the last couple of years.

Figure 2: NYMEX Non-commercial net and short futures contracts: WTI January 2004 – July 2018

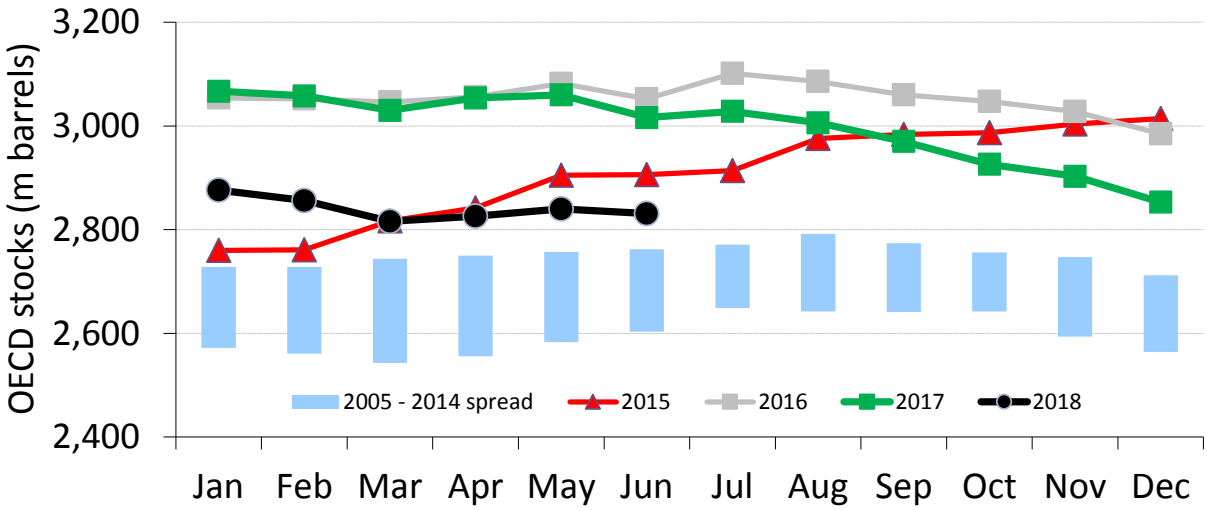


Source: Bloomberg LP/NYMEX/ICE (2018)

OECD stocks

OECD total product and crude inventories at the end of June (the latest data point available) were estimated by the IEA to be 2,831m barrels, down by 9m barrels versus the level reported for May. This compares to a 10-year average decline for June of 9m barrels. Inventories have been tightening since the middle of 2017, and remain around 60m barrels above the 'normalised' (pre-2015) range. We expect them to continue to tighten over the rest of 2018.

Figure 3: OECD total product and crude inventories, monthly, 2004 to 2018



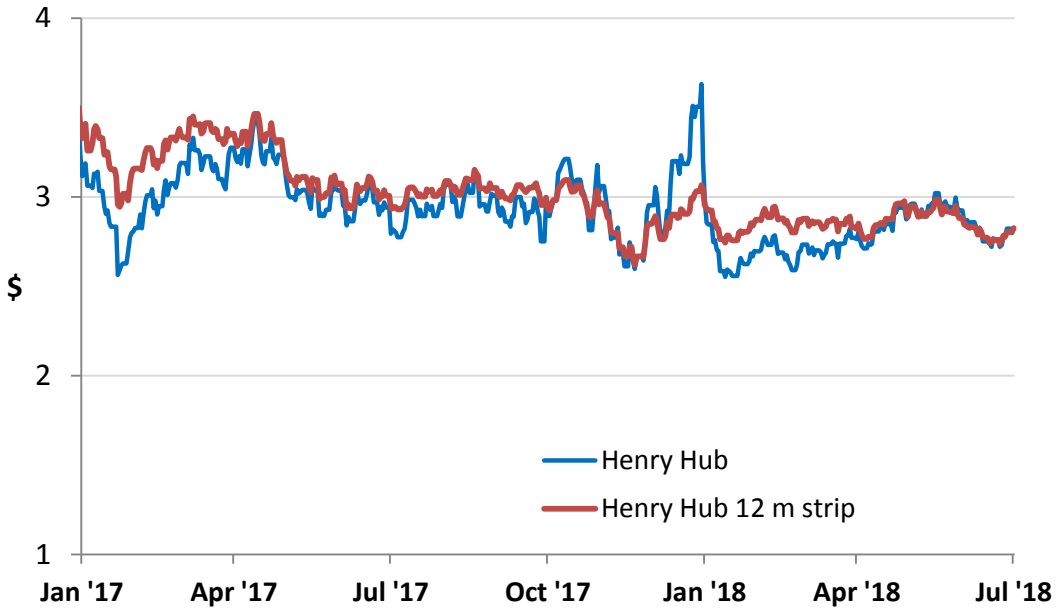
Source: IEA Oil Market Reports (July 2018 and older)

ii) Natural gas market

The US natural gas price (Henry Hub front month) opened July at $2.92/mcf (1,000 cubic feet) and drifted lower over the first half of the month to a low of $2.74/mcf, before recovering to end the month at $2.78/mcf. The spot gas price has averaged $2.83/mcf so far in 2018, which compares to an average gas price of $3.02 in 2017, $2.55/mcf in 2016 and $2.61/mcf in 2015. The price averaged around $3.90/mcf over the preceding five years (2010-2014).

The 12-month gas strip price (a simple average of settlement prices for the next 12 months' futures prices) aso declined over the month, opening at $2.88/mcf and closing at $2.82 /mcf. The strip price averaged $3.12 in 2017 and $2.84 in 2016, having averaged $2.86 in 2015, $4.18 in 2014 and $3.92 in 2013.

Figure 4: Henry Hub gas spot price and 12m strip ($/Mcf) January 31 2017 to July 31 2018



Source: Bloomberg LP

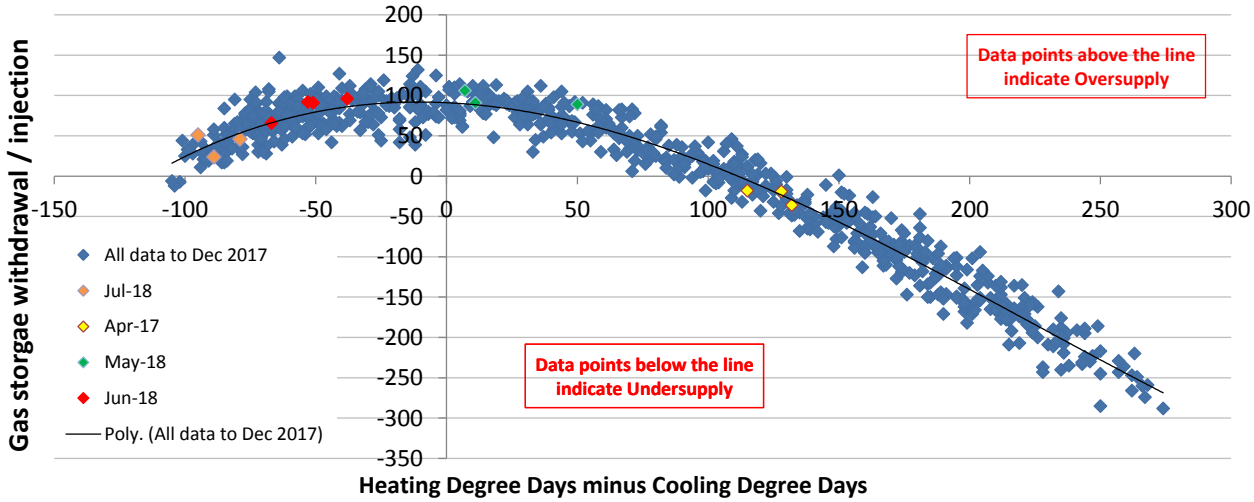
Factors which strengthened the US gas price in July included:

- **Depressed gas inventories**
  US natural gas inventories were estimated to be around 2.273 Tcf at the end of July, 0.55 Tcf lower than the 10 year average, and very close to the 10 year low. In order for inventories to reach 'full' at the end of November, it would require an oversupply for the remainder of the year to be around 3-4 Bcf/day.

Factors which weakened the US gas price in July included:

- **Strong US onshore natural gas production**
  Onshore US natural gas production averaged 87.5 Bcf/day in May 2018 (the latest available data point), up by 0.8 Bcf/day on the level reported for April. Onshore production has risen by 10.5 Bcf/day versus the level reported twelve months before, the highest year-on-year growth recorded. Rising associated gas supply from shale oil, and a pickup of activity in the Marcellus basin, are the key reasons for the rise in production: both look set to continue for the rest of 2018.
- **Structurally balanced market**
  Adjusting for the impact of weather in July, the most recent injections of gas into storage suggest the market is, on average, operating in balance (as indicated by the orange dots on the graph below).

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

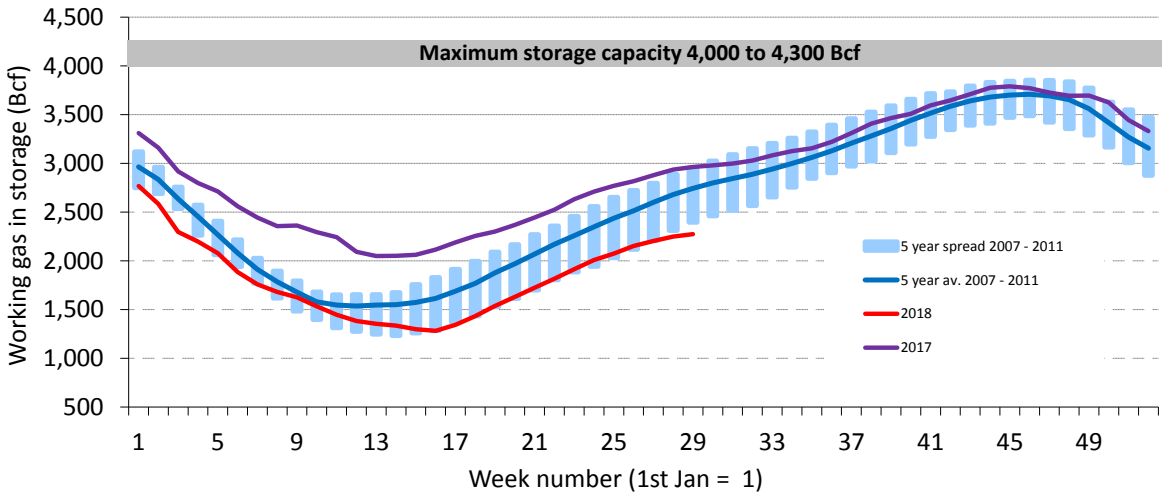


Source: Bloomberg LP; Guinness Asset Management

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 July were reported by the EIA to be 2.273 Tcf. The withdrawal season started with inventories peaking at 3.8 Tcf in mid-November, the lowest starting point of the winter season for US gas inventories since November 2014. Exceptionally cold weather and, until recently, an undersupplied market has brought inventories back from being at the top of the ten year range (in November and December) to being below seasonal norms during the summer.

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



Source: Bloomberg; EIA (July 2018)

2. MANAGER'S COMMENTS

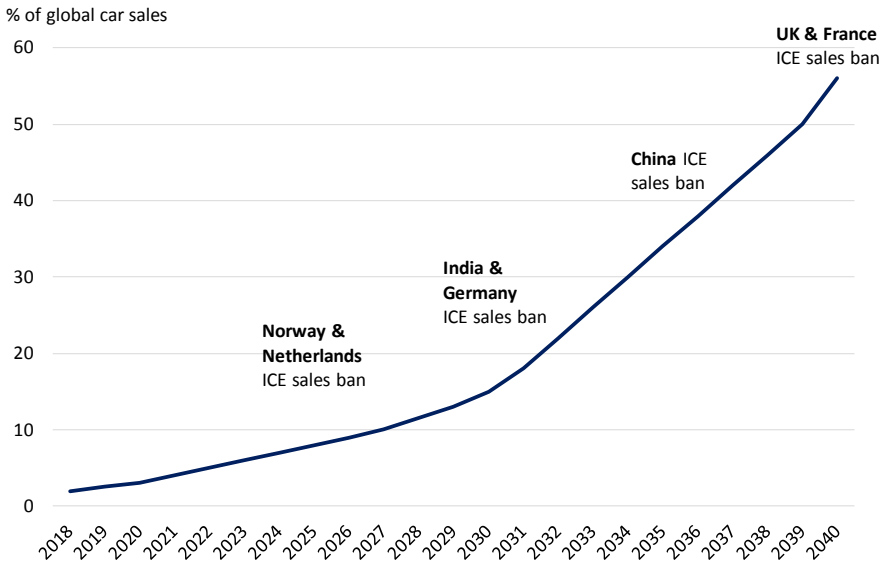
Edging into the mainstream: how will electric vehicles impact future global oil demand?

Last summer we wrote a piece exploring the impact of electric vehicles on global oil demand. Over the last twelve months, there have been numerous developments in the EV sector, political and economic. With this in mind we thought it would be useful to update our thoughts and see whether the conclusions we reached then are still valid today.

The political push for EVs gathers pace

It was just over a year ago that the UK and French governments announced their intention to ban the sale of pure internal combustion engine (ICE) cars by 2040. Since then, we have seen China announce a similar plan by 2035, whilst India and Germany have proposed more aggressive plans, banning the sale of new gasoline and diesel cars by 2030. One method, then, to assess the penetration of EVs into the global auto market is to take the bans on sales of new ICE vehicles at face value. We show this in the chart below.

EV contribution to global car sales to meet ICE sales bans



Source: Wood Mackenzie; Guinness Asset Management

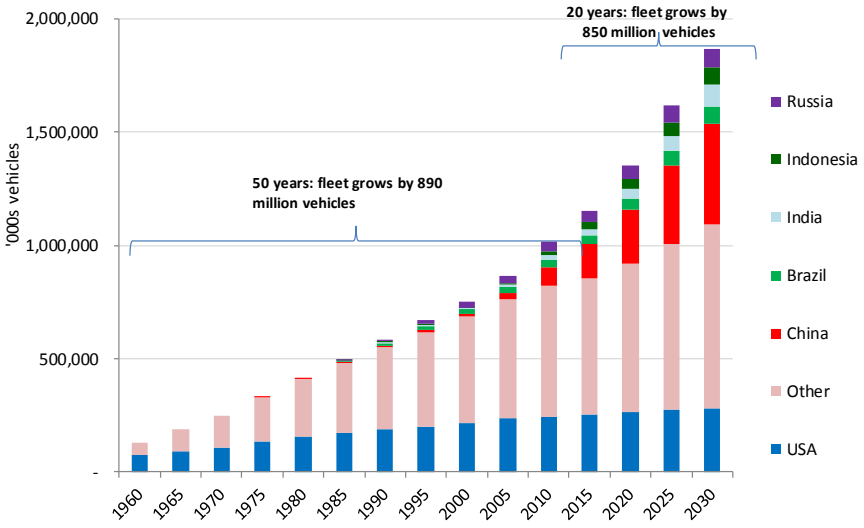
The implication is that by 2025, EV sales would need to be approaching 10% of total global auto sales, rising to 15% by 2030, then a much sharper increase to over 50% of sales by 2040. How likely are these bans to be effective in the timescales given? On the one hand, there are certain European governments, Norway being the poster child for this movement, who are serious about the required infrastructure, the required subsidies, and who have a population rich enough to participate. At the other end of the spectrum, we view India's target to ban ICE sales by 2030 as highly unlikely, given the absence of any meaningful EV infrastructure plan. Germany's call for an ICE ban in 2030 is also an interesting one since, as recently as 2016, the German Transport Minister described the plan as "totally unrealistic". Nevertheless, plotting the ICE bans country by country is an interesting starting point.

World vehicle fleet – pace of expansion

We are now in an era where the absolute growth rate for light vehicles is expanding rapidly. According to HIS, global car sales grew in 2017 by 2.4% to 94.5m units, almost 50% higher than the annual average sales rate in the 2000s (c.62m units), and around double the annual average sales rate of the 1990s (c.47m units). The 2017 sales growth rate of 2.4% was slower than the growth rate seen in 2016, but keeps the world on track to achieve around 100m of sales by 2020. Unsurprisingly, the growth mainly comes from emerging markets. China is currently selling over 28m light vehicles each year, whilst India still only has around 30m cars, but is developing a sophisticated highway system, capable of supporting far more.

Applying an average sales growth rate 2.9% (just below the 3% growth rate recorded between 1990 and 2016), combined with an expected vehicle retirement rate, produces the following forecast for the world light vehicle population to 2030:

World light vehicle population (1960-2030e)



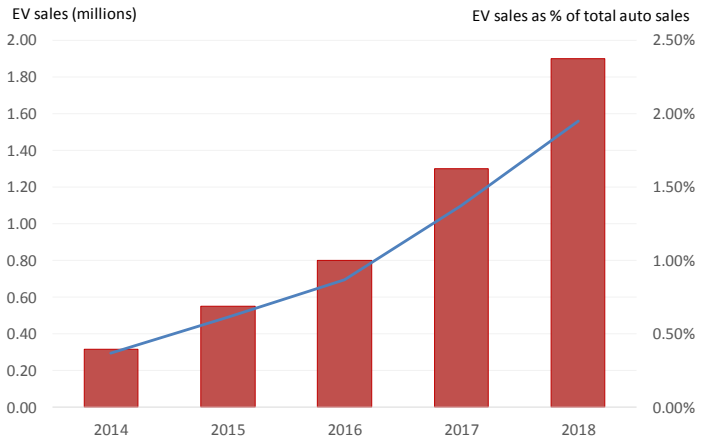
Source: Wood Mackenzie; Guinness Asset Management

As we stated before, this sets up the likelihood the global vehicle fleet grows by as much over 20 years, from 2010 to 2030, as it did in the previous 50 years.

Electric vehicles – pace of adoption

For all the interest in the roll-out of the EV industry, actual sales remain at low levels, relative to overall auto sales. In 2017, global sales of EVs totalled around 1.3m vehicles, up from 0.8m vehicles in 2016. This lifted EV's share of the auto sales market from around 0.8% to 1.3%. The largest increase in sales volume in 2017 came from China (+0.3m units), followed by North America (+0.08m units) and Europe (+0.06m units). EV sales in 2018 are expected to be up by nearly 50% to 1.9m units, with China again leading the way.

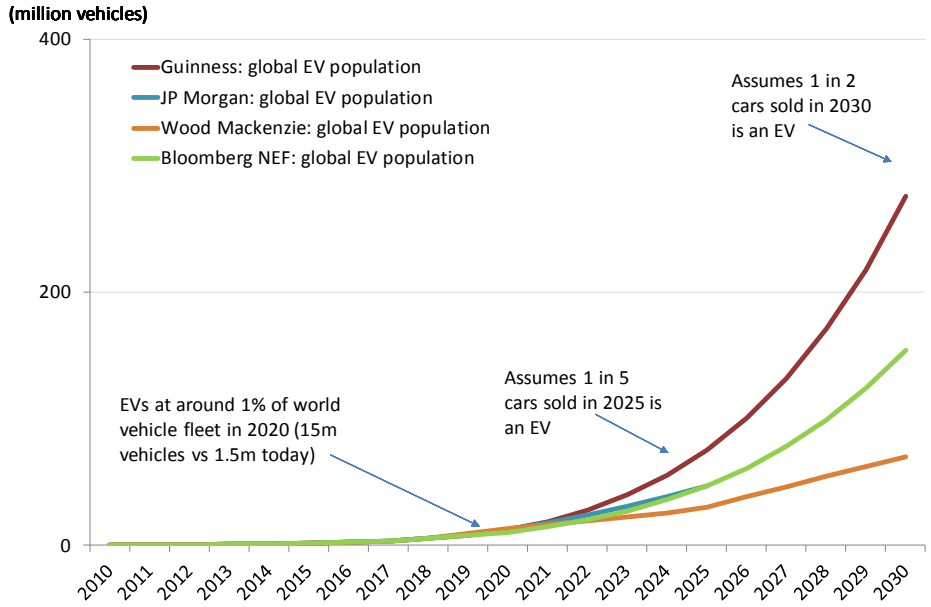
World EV sales (2014-2018e)



Source: EV volumes; Guinness Asset Management

Looking further ahead, we expect a continuation of the 'S' curve now developing for EV sales. By 2025, we assume that 20% of total vehicles sales are EV, rising to 50% of sales in 2030. Our assumptions imply the global EV population reaching around 15m units by 2020, then around 50m units in 2025 and around 275m units in 2030. Below, we compare our forecasts with our recent efforts from banks and independent research houses:

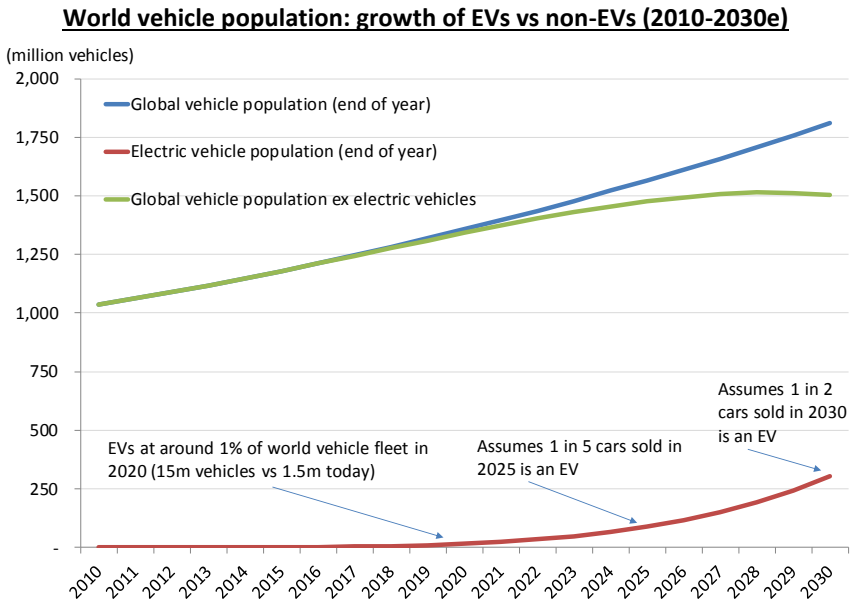
World EV population (2010-2030e)



Source: Wood Mackenzie; JP Morgan; Bloomberg New Energy Finance; Guinness Asset Management

As before, we note that the Guinness EV forecast is higher than those produced by other observers. We are content with this since, given the object is to assess the impact of EV penetration on oil demand, we prefer to pitch ourselves at the 'aggressive' end of the spectrum.

What does the Guinness scenario imply for the size of the ICE population?



Source: IHS; Guinness estimates

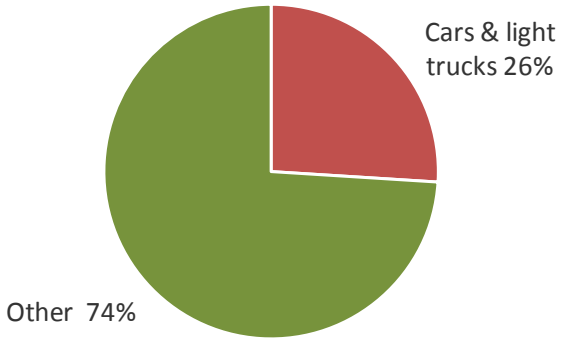
The results of our modelling are striking. Despite the rapid adoption of EVs that is assumed, the offsetting impact of global vehicle population growth implies that the global population of ICE vehicles does not peak until the late 2020s. And after peaking at around 1.5bn, the population of ICE vehicles moves into relatively shallow decline, returning to the number of ICE vehicles that we see in the world today (1.2bn) in the mid 2030s.

As EV adoption progresses over the next 10 or 15 years, we must acknowledge that the fuel efficiency of the ICE portion of the market will improve, which will put further pressure on oil demand growth from the ICE fleet. On the other hand, around 50% of EVs are being sold as hybrids (a figure that will decline over time), which will still generate significant gasoline and diesel demand. Taken together, we continue to believe a growing fleet, improving fuel efficiency and EV penetration points to oil demand from cars and light vehicles peaking in the mid to late 2020s.

How important is oil demand from light vehicles in the context of total oil demand?

Given how visible it is in everyday life, there is a danger of overemphasising the importance of oil demand that is generated by passenger vehicle use versus other sources of demand. The reality is that cars and light trucks account for around 26% of global oil usage, with other sources of transportation (heavy vehicles, air, shipping and rail) accounting for around 31% of demand, and petrochemicals, other industry and power account making up most of the rest. Electrification of heavier road vehicles will come eventually, particularly in cities, but is some way behind, mainly due to range issues.

Structure of global oil demand



Source of demand	%
Power	6%
Petrochemicals	13%
Other industry	11%
Cars & light trucks	26%
Heavy vehicles	18%
Air travel	6%
Shipping	6%
Rail	1%
Other	13%
Total	**100%**

Source: BP; Bernstein; Guinness Funds

Assessing the direction of oil demand growth over the next decade or two also, therefore, requires consideration of how other uses of oil are likely to evolve. Between 2017 and 2030, real GDP is expected to grow by 60% from $75trn to around $120trn (World Bank). Behind this, we think there will be a very significant increase in the number of trucks, air passenger miles, ethylene production and seaborne trade:

- **Global truck fleet** rising from 400m in 2017 to 550m in 2030
- **Air revenue passenger kms** rising from 10trn in 2017 to 15trn in 2030
- **Seaborne trade** rising from 57trn ton miles in 2017 to 90trn ton miles in 2030
- **Ethylene demand** rising from 150m tons in 2017 to 235m tons in 2030

Source: IHS; IATA; IMF; Bernstein; Guinness estimates

In isolation, these impacts would put enormous upward pressure on oil demand, implying average growth of around 2m b/day each year between now and 2030. However, once we factor in improving efficiency of the light vehicle fleet, efficiencies for other types of vehicle and in other industries, plus the penetration of EVs, the net effect is persistent but slowing demand growth into 2030. And when will oil demand then peak? The most likely scenario would be sometime around the mid 2030s, reaching a peak of somewhere between 110-120m b/day. This would imply average demand growth of 1m b/day between now and the peak: higher than that in the near years and tailing off in later years.

Falling battery prices and manufacturing economies of scale are likely to bring price-competitive EVs, particularly in the second half of the 2020s as EVs compete on an unsubsidized total cost of ownership basis across mass-market vehicle classes, and not just the higher end of the market. Significant challenges remain, in the form of raw material availability, charging infrastructure and battery quality. But even assuming the EV becomes a success, analysis of oil demand until the 2030s hinges more on trends in fuel efficiency, the size of the passenger vehicle fleet and the trajectory for global GDP growth. Today, the signs still point to significant new oil resources being required to keep up with continuing demand growth.

1) PERFORMANCE Guinness Global Energy Fund

The main index of oil and gas equities, the MSCI World Energy Index, was up by 1.5% in July, while the MSCI World Index was up by 3.2%. The Fund was up by 0.7% (class E) in the month, underperforming the MSCI World Energy index by 0.8% (all in US dollar terms).

Within the Fund, July's strongest performers were Helix Energy Solutions, Valero, Total, Gazprom and Conocophillips while the weakest performers were QEP Resources, Oasis, Halliburton, Sunpower and Newfield.

Performance (in USD) 31/07/2018

Annualised

% returns	1 year	3 years	5 years	10 years	1999 to date
Guinness Global Energy	25.3	5.9	-1.4	-1.2	10.5
MSCI World Energy Index	21.4	7.6	1.3	0.9	7.5

Calendar year

% returns	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007
Guinness Global Energy	9.0	-1.3	27.9	-27.6	-19.1	24.4	3.0	-13.6	15.3	61.8	-48.2	37.6
MSCI World Energy Index	5.6	5.0	26.6	-22.8	-11.6	18.1	1.9	0.2	11.9	26.2	-38.1	29.8

Source: Guinness Asset Management and Financial Express, bid to bid, gross income reinvested, in US dollars

Calculation by Guinness Asset Management Limited, simulated past performance prior to 31.3.08, launch date of Guinness Global Energy Fund. The Guinness Global Energy investment team has been running global energy funds in accordance with the same methodology continuously since November 1998. These returns are calculated using a composite of the Investec GSF Global Energy Fund class A to 29.2.08 (managed by the Guinness team until this date); the Guinness Atkinson Global Energy Fund (sister US mutual fund) from 1.3.08 to 31.3.08 (launch date of this Fund), the Guinness Global Energy Fund class A (1.49% OCF) from launch to 02.09.08, and class E (1.24% OCF) thereafter. Performance would be lower if an initial charge and/or redemption fee were included.

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

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

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

2) PORTFOLIO Guinness Global Energy Fund

Buys/Sells

The portfolio was actively rebalanced during July.

Sector Breakdown

The following table shows the asset allocation of the Fund at **July 31 2018**.

(%)	31 Dec 2010	31 Dec 2011	31 Dec 2012	31 Dec 2013	31 Dec 2014	31 Dec 2015	31 Dec 2016	31 Dec 2017	31 July 2018	*Chg YTD*
Oil & Gas	***93.3***	***97.9***	***97.3***	***93.7***	***93.7***	***95.1***	***96.7***	***98.4***	***96.7***	***-1.7***
Integrated	33.0	30.9	30.4	29.2	27.0	30.4	32.5	28.6	24.7	*-3.9*
Integrated – Can & Em Mkts	8.2	8.8	8.4	9.4	10.3	11.1	14.3	14.2	14.6	*0.4*
Exploration & production	37.1	41.1	40.3	35.4	36.2	36.5	35.4	37.0	39.1	*2.1*
Oil & Gas Storage & Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	3.9	*0.4*
Drilling	6.1	5.9	7.1	6.4	3.3	1.5	2.2	1.9	1.7	*-0.2*
Equipment & services	5.4	6.1	7.4	9.8	13.4	11.4	8.6	9.5	9.0	*-0.5*
Refining and marketing	3.5	5.1	3.7	3.5	3.5	4.2	3.7	3.7	3.7	*0.0*
Solar	**3.2**	**1.3**	**1.2**	**2.6**	**3.7**	**4.7**	**0.9**	**1.4**	**0.4**	***-1.0***
Coal & consumables	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	***0.0***
Construction & engineering	**0.3**	**0.4**	**0.6**	**1.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	***0.0***
Cash	**3.2**	**0.4**	**0.9**	**2.7**	**2.6**	**0.2**	**2.4**	**0.2**	**2.9**	***2.7***
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	

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

The Fund at July 31 2018 was on a price to earnings ratio (P/E) for 2018 of 14.4x versus the S&P 500 Index at 17.8x as set out in the following table:

	2011	2012	2013	2014	2015	2016	2017	2018
Guinness Global Energy Fund P/E	9.0	9.3	10.0	11.0	23.5	40.1	25.5	14.4
S&P 500 P/E	29.2	29.1	26.2	24.3	28.1	26.6	22.6	17.8
Premium (+) / Discount (-)	*-69%*	*-68%*	*-62%*	*-55%*	*-16%*	*51%*	*13%*	*-19%*
Average oil price (WTI $/bbl)	95	94	98	93	49	43	51	65

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

Portfolio holdings

Our integrated and similar stock exposure (c.43%) is comprised of a mix of mid cap, mid/large cap and large cap stocks. Our four large caps are Chevron, BP, Royal Dutch Shell and Total. Mid/large and mid-caps are ENI, Statoil and OMV. At July 31 2018 the median P/E ratios of this group were 19.5x/13.6x 2017/2018 earnings. We also have two Canadian integrated holdings, Suncor and Imperial Oil. Both companies have significant exposure to oil sands in addition to downstream assets.

Our exploration and production holdings (c.36%) give us exposure most directly to rising oil and natural gas prices. We include in this category non-integrated oil sands companies, as this is the GICS approach. The stock here with oil sands exposure is Canadian Natural Resources. The pure E&P stocks have a bias towards the US (Newfield, Devon, Oasis and QEP Resources), with five other names (Apache, Occidental, ConocoPhillips, Noble, Anadarko) having a mix of US and international production and one (Tullow) which is African focused. One of the key metrics behind a number of the E&P stocks held is low enterprise value / proven reserves. Almost all of the US E&P stocks held also provide exposure to North American natural gas.

We have exposure to four (pure) emerging market stocks in the main portfolio, though one is a half-position, and in total represent 12% of the portfolio. Two are classified as integrateds (Gazprom and PetroChina) and two as E&P companies (CNOOC and SOCO International). Gazprom is the Russian national oil and gas company which produces approximately a quarter of the European Union gas demand and trades on 3.2x 2018 earnings. PetroChina is one of the world's largest integrated oil and gas companies and has significant growth potential and, alongside CNOOC, enjoys advantages as a Chinese national champion. SOCO International is an E&P company with production in Vietnam.

The portfolio contains one midstream holding, Enbridge, North America's largest pipeline company. With the growth of onshore oil and gas production expected in the US and Canada over the next five years, we believe Enbridge is well placed to execute its pipeline expansion plans.

We have useful exposure to oil service stocks, which comprise around 11% of the portfolio. The stocks we own are split between those which focus their activities in North America (land driller Unit Corp) and those which operate in the US and internationally (Helix, Halliburton and Schlumberger).

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

Portfolio at June 30th 2018 (for compliance reasons disclosed one month in arrears)

Guinness Global Energy Fund 30 June 2018				2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Stock	Curr.	Country	% of NAV	B'berg mean PER	B'berg mean PER	B'berg mean PER	B'berg mean PER	B'berg mean PER	B'berg mean PER	B'berg mean PER	B'berg mean PER	B'berg mean PER	B'berg mean PER	B'berg mean PER
Integrated Oil & Gas														
Chevron	USD	US	3.56	24.6	13.6	9.4	10.3	11.4	13.2	34.8	91.2	30.5	15.9	15.2
Royal Dutch Shell PLC	EUR	NL	3.57	16.0	11.3	8.4	8.3	11.0	9.7	20.5	33.7	18.3	12.4	11.1
BP PLC	GBP	GB	3.55	9.8	6.8	6.8	8.4	10.4	12.4	21.9	41.9	24.9	14.2	13.3
Total SA	EUR	FR	3.54	14.6	11.4	10.2	9.7	10.9	11.0	14.1	16.7	15.6	11.6	10.8
ENI SpA	EUR	IT	3.58	11.2	8.5	8.1	7.9	12.7	14.7	68.9	nm	27.8	13.7	12.5
Equinor ASA	NOK	NO	3.59	15.5	11.6	10.1	9.0	11.0	15.3	37.6	190.5	19.9	14.1	13.1
OMV AG	EUR	AT	3.34	19.5	12.2	15.2	10.6	13.1	16.1	14.4	14.7	9.9	9.2	8.9
			24.73											
Integrated / Oil & Gas E&P - Canada														
Suncor Energy Inc	CAD	CA	3.59	50.7	33.7	15.0	16.6	16.8	16.7	47.5	nm	28.7	17.2	14.7
Canadian Natural Resources Ltd	CAD	CA	3.73	19.7	19.5	20.5	29.8	21.1	13.8	341.4	nm	40.4	14.5	14.8
Imperial Oil	CAD	CA	3.57	22.0	19.1	11.9	10.5	13.6	11.5	24.6	72.6	34.1	16.5	16.2
			10.90											
Integrated Oil & Gas - Emerging market														
PetroChina Co Ltd	HKD	HK	3.73	8.5	6.9	6.7	7.8	8.6	8.5	26.4	103.3	40.2	16.0	14.5
Gazprom OAO	USD	RU	3.60	5.0	3.9	2.7	2.8	2.6	4.3	2.6	3.8	4.2	3.0	3.1
			7.33											
Oil & Gas E&P														
Occidental Petroleum Corp	USD	US	3.54	22.5	14.9	10.1	12.1	12.1	14.4	504.1	nm	93.2	17.6	16.6
ConocoPhillips	USD	US	3.55	19.2	11.7	8.2	12.2	12.4	13.1	nm	nm	111.7	17.6	16.6
Anadarko Petroleum Corp	USD	US	3.62	nm	42.3	23.2	21.9	17.6	16.0	nm	nm	nm	25.1	21.6
Apache Corp	USD	US	3.81	8.4	5.0	3.9	4.9	5.8	8.3	nm	nm	441.0	25.2	25.1
Devon Energy Corp	USD	US	3.67	13.5	7.4	7.3	13.6	10.4	8.5	17.8	nm	24.0	28.1	18.2
Noble Energy Inc	USD	US	3.45	20.9	17.0	13.4	15.4	11.4	15.1	618.9	nm	2205.0	30.9	22.5
QEP Resources Inc	USD	US	1.79	nm	8.9	7.5	9.9	8.8	8.7	nm	nm	nm	nm	91.5
Newfield Exploration Co	USD	US	3.47	5.9	6.6	7.4	12.5	16.8	16.4	41.7	28.1	14.1	8.9	7.3
Oasis Petroleum Inc	USD	US	1.69	nm	77.2	15.7	8.8	4.7	5.3	16.3	nm	nm	32.7	15.8
			28.59											
International E&Ps														
CNOOC Ltd	HKD	HK	3.73	17.0	9.8	7.4	7.9	8.1	9.7	28.8	nm	16.7	9.6	9.7
Tullow Oil PLC	GBP	GB	1.68	49.9	24.2	5.5	5.0	37.3	nm	nm	nm	16.9	10.5	10.4
Soco International PLC	GBP	GB	0.63	7.5	10.3	6.6	1.8	2.0	3.0	nm	nm	nm	20.6	13.2
			6.04											
Midstream														
Enbridge Inc	USD	CA	3.97	53.2	45.9	41.4	38.1	35.1	32.2	29.1	27.0	32.7	25.5	26.2
			3.97											
Drilling														
Unit Corp	USD	US	1.75	9.7	8.4	6.2	6.2	6.9	6.0	nm	nm	48.1	29.2	18.9
			1.75											
Equipment & Services														
Halliburton Co	USD	US	3.44	34.4	22.4	13.5	15.2	14.5	11.4	30.5	nm	38.8	18.4	13.6
Helix Energy Solutions Group Inc	USD	US	1.83	14.4	15.8	5.5	4.5	7.7	4.3	49.3	nm	nm	56.3	27.0
Schlumberger Ltd	USD	US	3.55	24.7	24.3	18.5	16.0	14.1	12.1	20.0	58.0	45.8	34.4	23.0
			8.82											
Solar														
JA Solar Holdings Co Ltd	USD	US	0.73	nm	1.0	nm	nm	nm	7.8	3.9	9.1	12.2	nm	nm
Sunpower Corp	USD	US	0.43	6.7	5.3	93.5	51.1	5.5	5.8	3.9	nm	nm	nm	nm
			1.16											
Oil & Gas Refining & Marketing														
Valero Energy Corp	USD	US	3.55	nm	69.8	27.9	22.7	27.0	18.2	12.6	30.1	22.7	15.8	11.3
			3.55											
Research Portfolio														
Cluff Natural Resources PLC	GBP	GB	0.22	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm
EnQuest PLC	GBP	GB	0.61	nm	5.3	6.1	1.8	2.0	3.8	36.1	2.4	nm	4.1	2.4
JKX Oil & Gas PLC	GBP	GB	0.11	0.8	0.9	1.1	1.5	2.9	7.8	nm	nm	nm	39.1	nm
Ophir Energy PLC	GBP	GB	0.03	nm	nm	nm	nm	nm	2.1	nm	nm	nm	23.1	9.2
Reabold Resources PLC	GBP	GB	0.27	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm
Shandong Molong Petroleum Machiner	HKD	HK	0.05	6.6	2.6	3.6	nm	nm	nm	nm	nm	nm	nm	nm
Sino Gas & Energy Holdings Ltd	AUD	AU	0.29	nm	nm	nm	166.7	nm	166.7	nm	nm	nm	nm	27.8
			1.57											
		Cash	1.59											
		Total	100											
		PER		15.8	10.4	8.9	9.2	10.0	10.8	22.5	39.1	25.1	14.3	12.7
		Med. PER		15.5	11.4	8.3	10.1	11.0	11.4	27.6	30.1	28.2	16.8	14.7
		Ex-gas PER		17.1	11.3	9.5	9.3	10.4	11.2	21.1	35.2	23.9	13.7	12.4

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.

3) OUTLOOK

i) Oil market

The table below illustrates the difference between the growth in world oil demand and non-OPEC supply over the last 12 years, together with IEA forecasts for 2018.

	2005	2006	2007	2008	*2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018E
													IEA	*IEA*
World Demand	**84.0**	**85.2**	**87.0**	**86.5**	**85.5**	**88.5**	**89.5**	**90.7**	***91.7***	***93.1***	***95.0***	***96.2***	***97.7***	***99.1***
Non-OPEC supply (includes Angola, Ecuador and Indonesia for periods when each country was outside OPEC[1])	**50.4**	**51.3**	**50.5**	**49.6**	**51.4**	**52.7**	**52.8**	**53.3**	***54.5***	***56.6***	***58.1***	***56.8***	***57.6***	***59.6***
Angola supply adjustment[1]	-1.2	-1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ecuador supply adjustment[1]	-0.5	-0.5	-0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Indonesia supply adjustment[2]	0.9	0.9	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.6
Non-OPEC supply (ex. Angola/Ecuador and inc. Indonesia for all periods)	**49.6**	**50.3**	**51.0**	**50.6**	**51.4**	**52.7**	**52.8**	**53.3**	**54.5**	**56.6**	**58.1**	**57.4**	**58.2**	**60.2**
Gabon/E Guinea supply adjustment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3
OPEC NGLs	4.3	4.3	4.3	4.5	5.1	5.5	5.9	6.4	*6.1*	*6.4*	*6.6*	*6.8*	*6.9*	*6.9*
Non-OPEC supply plus OPEC NGLs plus Gabon/E Guinea (ex. Angola/Ecuador and inc. Indonesia for all periods)	**53.9**	**54.6**	**55.3**	**55.1**	**56.5**	**58.2**	**58.7**	**59.7**	**60.6**	**63.0**	**64.7**	**64.2**	**65.4**	**67.4**
Call on OPEC-12[3]	30.1	30.6	31.7	31.4	29.0	30.3	30.8	31.0	31.1	30.1	30.3	32.0	32.3	31.7

[1]Angola joined OPEC at the start of 2007, Ecuador rejoined OPEC at the end of 2007 (having previously been a member in the 1980s)
[2]Indonesia left OPEC as of the start of 2009; rejoined at start of 2016, but is now suspended again
[3]Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi, U.A.E. Venezuela

Source: 2003 - 2008: IEA oil market reports; 2009 - 17: July 2018 Oil market Report

Global oil demand in 2017 was 10.7m b/day higher than the pre-financial crisis (2007) peak. This means the combined effect of the 2007/08 oil price spike and the 2008/09 recession was shrugged off remarkably quickly, thanks to growth in demand from emerging markets. The IEA forecast a rise of 1.4m b/day in 2018, which would take oil demand to an all-time high of 99.1m b/day.

OPEC

In December 2011, OPEC-12 introduced a group-wide target of 30m b/day without specifying individual country quotas. At the date of the announcement, and in the period since, OPEC's production has been complicated by numerous issues: notably (1) erratic production from Libya, affected by the ongoing civil war; (2) depressed production in Iran due to western sanctions over its nuclear programme; (3) real difficulty in forecasting how Iraq might develop.

In response to lower Libyan, Iranian and Nigerian production, and to cope with rising global oil demand, the three key swing producers within OPEC (Saudi, Kuwait and UAE) each raised their production significantly, as the following table shows:

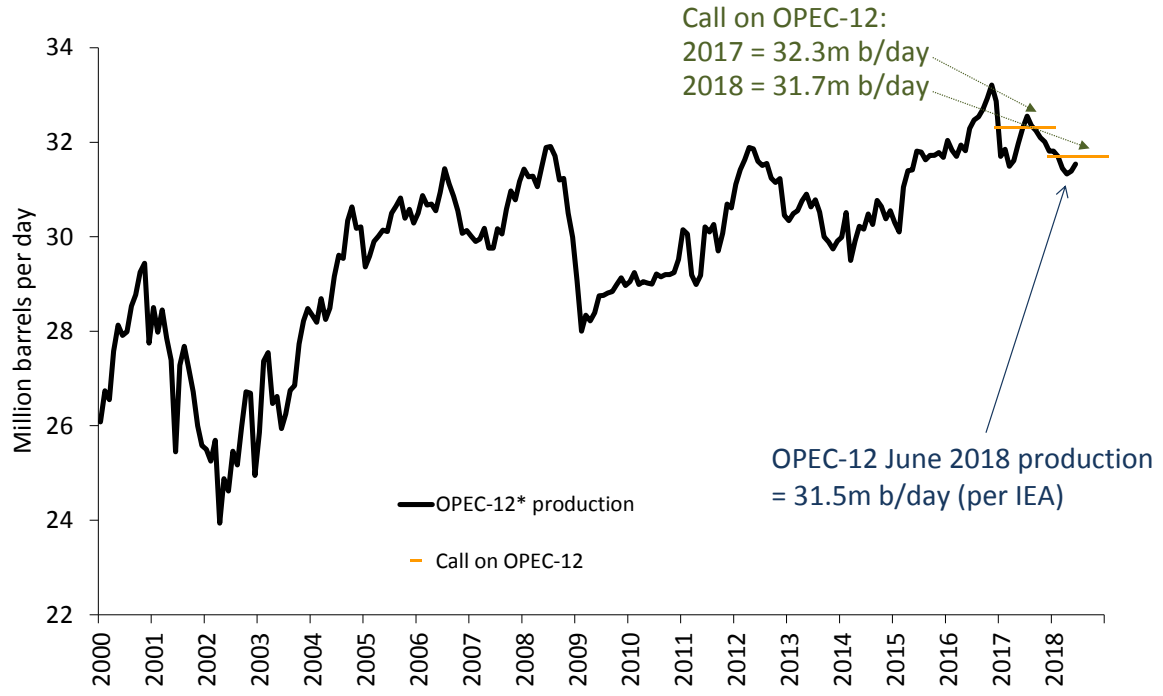
('000 b/day)	31-Dec-10	30-Nov-14	31-Dec-16	30-Jun-18	Current vs Dec 2010 (start of Arab Spring)	Current vs Nov 2014 (OPEC hold mkt share)	Current vs Dec 2016 (OPEC cut production)
Saudi	8,250	9,650	10,480	**10,300**	2,050	650	-180
Iran	3,700	2,780	3,730	**3,780**	80	1,000	50
Iraq	2,385	3,370	4,630	**4,500**	2,115	1,130	-130
UAE	2,310	2,800	3,070	**2,890**	580	90	-180
Kuwait	2,300	2,790	2,860	**2,760**	460	-30	-100
Nigeria	2,220	1,970	1,500	**1,620**	-600	-350	120
Venezuela	2,190	2,350	2,080	**1,380**	-810	-970	-700
Angola	1,700	1,640	1,670	**1,410**	-290	-230	-260
Libya	1,585	580	630	**690**	-895	110	60
Algeria	1,260	1,100	1,110	**1,050**	-210	-50	-60
Qatar	820	650	620	**610**	-210	-40	-10
Ecuador	465	561	550	**520**	55	-41	-30
OPEC-12	**29,185**	**30,241**	**32,930**	**31,510**	**2,325**	**1,269**	**-1,420**

Source: Bloomberg, DOE

The effect from 2011 to the middle of 2014 was OPEC-12 (ex Indonesia) producing at around 30m b/day, plus or minus 1m b/day, in an attempt to keep the global oil market in balance.

From the second half of 2014, we moved into a period where the global oil balance became looser, driven principally by surging non-OPEC supply (+2.4m b/day in 2014 and +1.4m b/day in 2015). The effect of $100+ bbl oil, enjoyed for most of the 2011-2014 period, emerged in the form of an acceleration in US shale oil production and an acceleration in the number of large non-OPEC (ex US onshore) projects reaching production.

Figure 7: OPEC-12 apparent production vs call on OPEC 2000 – 2018



Source: IEA Oil Market Report (July 2018 and prior); Guinness estimates

OPEC-12 met in November 2014, with the growing looseness in the physical market and a falling oil price (in the mid $70s at the time of the meeting) prompting a significant change in strategy to one that prioritised market share over price. As a result, there was no quota cut, as many had anticipated, and a confirmation that the 30m b/day target would be maintained. Post the November 2014 meeting, OPEC-14 (Indonesia and Gabon joined the group) not only maintained their quota but also raised production significantly, up over 18 months by 2.5m b/day. Iraq recovered its production by 1.2m b/day; Iran by 0.8m b/day post the lifting of sanctions relating to their nuclear programme; and Saudi by 0.9m b/day.

In November 2016, OPEC stepped back from their market share stance, announcing plans for the first production cut since 2008, opting for a new production limit of 32.5m b/day. The announcement represented a cut of 1.2m b/day (all numbers for OPEC-14 including Gabon). There was also an understanding that non-OPEC, including Russia, would cut production by 0.6m b/day, which would bring the total reduction to 1.8m b/day.

The November 2016 announcement amounted to a 5% cut for all members except for 1) Libya and Nigeria, recognising their unusually depressed levels of production due to unrest, and 2) Iran, recognising its journey back to normalised production post the lifting of sanctions in January 2016. The agreed cuts came into effect on 1 January 2017, and were initially designed to be kept in place for six months, but were subsequently extended to the end of 2018. Compliance with the cuts was very strong and, after been delayed initially by a variety of temporary factors, inventories started to decline from mid 2017. Having originally been excluded from the cuts, Libya and Nigeria were subsequently included in the quota system.

OPEC showed clear intention to end the production cuts in a manner that was consistent with maintaining a balanced market. And in June 2018, with Brent oil averaging around $75/bl and OPEC compliance to the agreed production cuts running at just over 150%, OPEC met in Vienna. At the conclusion of their meeting, OPEC's headline announcement was "to strive to adhere to the overall conformity level of OPEC-12, down to 100%, as of 1 July 2018". Details were skant but we interpret the announcement as implying an increase in production of around 0.6m b/day. Some non-OPEC members, led by Russia, are expected to increase production as well, taking the potential increase in overall OPEC and non-OPEC volumes potentially as high as 1m b/day for the second half of 2018.

The meeting confirmed that OPEC remain committed to delivering a reasonable oil price to satisfy their own economies but also to incentivise investment in long term projects. Saudi's actions at the head of OPEC appear designed to achieve an oil price that to some extent closes their fiscal deficit ($70-75/bl is needed to close the gap fully), whilst not spiking the oil price too high and over-stimulating non-OPEC supply. Longer term, we believe that Saudi seek a 'good' oil price, in excess of current levels to balance their fiscal needs, but they realise that patience is required to achieve that goal.

Overall, we reiterate two important criteria for Saudi:

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

Nothing in the market in recent years has changed our view that OPEC can put a floor under the price – as they did in 2008, 2006, 2001, 1998 – and again in 2016. Recent meetings and decisions indicate that OPEC have the resolve to continue in this manner.

Supply looking forward

The non-OPEC world has, since the 2008 financial crisis, grown its production more meaningfully than in the seven years before 2008. The growth was 0.9% p.a. from 2001-2008, increasing to 1.7% p.a. from 2008-2017.

Growth in the non-OPEC region since the start of the decade has been dominated by the successful development of shale oil and oil sands in North America (up around 6m 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.

After the strongest year for non-OPEC production in 2014 (+2.4m b/day) since 1978, non-OPEC growth in 2015 was also strong, at 1.4m b/day. Whilst the sub-$60 oil environment has caused significant deferral and cancellation of new developments, start-up projects that were sanctioned before the fall in the oil price are still coming to completion, creating this resilience in production. However, the effect of a low oil price impacted more in 2016, when non-OPEC supply fell by around 0.8m b/day. Non-OPEC supply recovered by 0.7m b/day in 2017, as US onshore production swung from decline back to growth.

The growth in US shale oil production, in particular from the Permian basin, raises the question of how much more there is to come and at what price. New oil production from these sources peaked in April 2015 at around 4m b/day, then declined by around 1.1m b/day, but has now passed the previous peak. Our assessment is that US shale oil is a capital intensive source of oil but one where real growth is viable, on average, at around $50 oil prices. In particular, there appears to be ample inventory in the Permian basin to allow growth well into the 2020s. In total, it could be comparable in size to the UK North Sea, i.e. it could grow by around a further 4m b/day over the next five years, but only if the price is sufficiently high to incentivise growth. The rate of development is heavily dependent on the cashflow available to producing companies, which tends to be recycled immediately into new wells, and the underlying cost of services to drill and fracture the wells. Naturally, cashflows available for reinvestment in a $60 world are far lower than in a $100 world, but with efficiency improvements, enough to see growth sustaining.

Offsetting US onshore shale oil growth, we expect to see non-OPEC supply outside the US weakens, as the queue of large conventional project start-ups slows. Since 2014, the number of project start-ups in this region has been sustained at a high level, despite lower oil prices, since projects that were sanctioned before the 2014 (when oil was $100+) have continued to come onstream. We believe 2019 marks a point, however, when the cancellation of projects that should have been sanctioned in 2015/16 starts to bite. A lack of supply response in the non-OPEC ex US region will increase the 'call' on US shale to balance the market.

Looking longer term, other opportunities to exploit unconventional oil likely exist internationally using techniques established in the US, notably in Argentina (Vaca Muerta), Russia (Bazhenov), China (Tarim and Sichuan) and Australia (Cooper). However, the US is far better understood geologically; the infrastructure in the US is already in place; service capacity in the US is high; and the interests of the landowner are aligned in the US with the E&P company. In most of the rest of the world, the reverse of each of these points is true, and as a result we see international shale being 10+ years behind North America.

Demand looking forward

The IEA estimate that 2017 oil demand growth was 1.5m b/day, and they expect a further increase of 1.4m b/day in 2018, taking demand to just over 99m b/day. Generally speaking, we have seen demand forecasts revised consistently higher since 2014, with the positive effect of lower oil prices continuing to surprise.

The IEA's global demand estimate for 2018 comprises an increase in non-OECD demand of 1.1m b/day and OECD demand growth of 0.3m b/day. The components of this non-OECD demand growth can be summarised as follows:

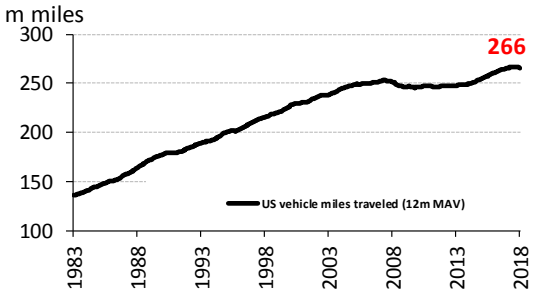
Figure 8: Non-OECD oil demand

m b/day	Demand								Growth						
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018e**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018e**
Asia	20.3	21.4	22.1	22.8	24.0	24.8	25.8	26.7	1.1	0.7	0.7	1.2	0.8	1.0	0.9
Middle East	7.4	7.8	7.9	8.4	8.4	8.3	8.3	8.4	0.4	0.1	0.5	0.0	-0.1	0.1	0.1
Latin America	6.2	6.4	6.7	6.8	6.7	6.6	6.5	6.5	0.2	0.3	0.1	-0.1	-0.1	-0.1	0.0
FSU	4.4	4.6	4.7	4.66	4.6	4.7	4.7	4.8	0.2	0.1	0.0	-0.1	0.2	0.0	0.1
Africa	3.5	3.8	3.9	3.8	4.1	4.3	4.3	4.4	0.3	0.1	-0.1	0.3	0.2	0.0	0.1
Europe	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**42.5**	**44.7**	**46.0**	**47.2**	**48.4**	**49.4**	**50.4**	**51.6**	**2.2**	**1.3**	**1.2**	**1.2**	**1.0**	**1.0**	**1.2**

Source: IEA Oil Market Report (July 2018)

Asia has settled down into a steady pattern of growth since 2010, and accounts for much of expected growth in 2018. Historically, China has been the most important component of this growth and continues to be a major component, although signs are emerging that India may also start to grow rapidly.

OECD demand in 2018 is forecast to be up by 0.3m b/day. In the US, the sharp fall in gasoline prices since 2014 has stimulated a reversal in improving fuel efficiency, as drivers switch back to purchasing larger vehicles, and a rise in total vehicle miles travelled, as shown in the chart opposite. Total vehicle miles travelled had stalled between 2007 and 2014, after two decades of growth, and are now growing again at a rate of around 1-2% per year.



The trajectory of global oil demand over the next few years will be a function of global GDP, pace of the 'consumerisation' of developing economies, and price. At a $60/bl oil price, the world oil bill as a percentage of GDP is around 2.5% and this will still be a stimulant of multi-year demand growth. If oil prices move to a higher range (say around $75/bbl, representing 3%+ of GDP), we probably return to the pattern established over the past 5 years, with a flatter picture in the OECD more than offset by strong growth in the non-OECD area. Flatter OECD demand reflects improving oil efficiency over time, dampened by economic, population and vehicle growth. Within the non-OECD, population growth and rising oil use per capita will both play a significant part. Overall, we would not be surprised to see annual non-OECD demand growth of around 1.5m b/day by the end of the decade. This would represent a growth rate of 3% p.a., no greater than the growth rate over the last 15 years (3.2% p.a.).

We keep a close eye on developments in the 'new energy' vehicle fleet (electric vehicles; hybrids etc), but see nothing that makes a significant dent on the consumption of gasoline and diesel in the next few years. Sales of electric vehicles (pure electric and plug-in hybrid electrics) globally were around 1.2m in 2017, up from 0.8m in 2016. Sales of 1.6m electric vehicles represents around 1.5% of total light vehicle sales, and increases EV's share of the world car fleet to 0.25%. We expect to see EV sales accelerate in 2018 to around 1.9m, or 2% of total global sales. Even applying an aggressive growth rate to EV sales, we see EVs comprising only around 0.6% of the global car fleet in 2020. Looking further ahead, we expect the penetration of EV's to accelerate, causing global gasoline demand to peak at some point in the second half of the 2020s. However, owing to the weight of oil demand that comes from sources other than passenger vehicles (around 70%), which we expect to continue growing linked to GDP, we expect total oil demand not to peak until the mid 2030s.

Conclusions about oil

The table below summarises our view by showing our oil price forecasts for WTI and Brent in 2017 against their historic levels, and rises/falls in percentage terms that we have seen in the period from 2002 to 2017.

Figure 9: Average WTI & Brent yearly prices, and changes

Oil price (inflation adjusted)																		*Est*
12 month MAV	1986-2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
WTI	30	33	38	49	66	75	82	104	68	84	99	94	98	93	49	45	51	64
Brent	30	32	35	46	64	75	82	103	67	84	115	112	108	99	52	45	54	68
Brent/WTI (12m MAV)	**30**	**33**	**37**	**48**	**65**	**75**	**82**	**104**	**68**	**84**	**107**	**103**	**103**	**96**	**51**	**45**	**53**	**66**
Brent/WTI y-on-y change (%)		8%	12%	30%	37%	15%	9%	26%	-35%	24%	27%	-4%	0%	-7%	-47%	-11%	17%	26%
Brent/WTI (5yr MAV)	30	25	32	37	42	51	61	75	79	82	89	93	93	99	92	80	69	62

We expect oil to trade in a $55-70/bl range in the near term, supported at the lower end by OPEC. If this price range persists, we expect North American unconventional supply to sustain growth. We believe that the 'call' on unconventional supply, however, is likely to grow into the end of the decade, as conventional non-OPEC supply declines.

The world oil bill at around $60/bl would represent 2.5% of 2018 Global GDP, 26% under the average of the 1970 – 2015 period (3.4%). A return to oil representing 3.4% of GDP implies an oil price of around $80/bl.

We believe that Saudi's long-term objective remains to maintain a 'good' oil price, similar to current spot levels, and that will allow the country to IPO Saudi Aramco successfully in the next year or so.

Natural gas market

US gas demand

On the demand side for the US, industrial gas demand and power generation gas demand, each about a quarter of total US gas demand, are key. Commercial and residential demand, which make up a further quarter, have been fairly constant on average over the last decade – although yearly fluctuations due to the coldness of winter weather can be marked.

Industrial demand (of which around 35% comes from petrochemicals) tends to trend up and down depending on the strength of the economy, the level of the US dollar and the differential between US and international gas prices. Between 2000 and 2009 industrial demand was in steady decline, falling from 22.2 Bcf/day to 16.9 Bcf/day. Since 2009 the lower gas price (particularly when compared to other global gas prices) and recovery from recession has seen demand rebound, up in 2017 to around 21.6 Bcf/day.

Electricity gas demand (i.e. power generation) is affected by weather, in particular warm summers which drive demand for air conditioning, but the underlying trend depends on GDP growth and the proportion of incremental new power generation each year that goes to natural gas versus the alternatives of coal, nuclear and renewables. Gas has been taking market share in this sector: in 2017, 33% of electricity generation was powered by gas, up from 22% in 2007. The big loser here is coal which has consistently given up market share over the past 10 years.

Bcf/day	2007	2008	*2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018E
US natural gas demand:												
Residential/commercial	21.2	22.0	21.6	21.6	21.6	19.2	22.4	23.4	21.4	20.5	20.9	21.7
Power generation	18.7	18.2	18.8	20.2	20.8	24.9	22.3	22.3	26.5	27.3	25.3	26.9
Industrial	18.2	18.2	16.9	18.5	19.0	19.7	20.3	20.9	20.6	21.1	21.6	22.2
Pipeline exports (Canada & Mexico)	2.1	2.5	2.8	2.9	4.1	4.4	4.4	4.1	4.9	6.3	6.2	7.0
LNG exports	-	-	-	-	-	-	-	-	0.1	1.0	2.6	3.4
Pipeline/plant/other	5.2	5.3	5.5	5.6	5.8	6.1	6.7	6.3	6.5	6.4	6.5	6.4
Total demand	**65.4**	**66.2**	**65.6**	**68.8**	**71.3**	**74.3**	**76.1**	**77.0**	**80.0**	**82.6**	**83.1**	**87.6**
Demand growth	**4.0**	**0.8**	**- 0.6**	**3.2**	**2.5**	**3.0**	**1.8**	**0.9**	**3.0**	**2.6**	**0.5**	**4.5**

Source: EIA; Simmons; Guinness estimates

Total gas demand in 2017 (including Canadian, Mexican and LNG exports) was 83.1 Bcf/day, up by just 0.5 Bcf/day (0.6%) versus 2016 but 5 Bcf/day (6.5%) higher than the 5 year average. LNG exports rose significantly this year (+2 Bcf/day), but offset by a 2 Bcf/day decline in demand from power generation, owing to normalising weather and gas to coal utility switching, prompted by prices back above $3/mcf.

US demand outlook

We expect US demand in 2018, assuming prices remain around $3/mcf, to exhibit strong growth of around 4.5 Bcf/day. We see several sources of higher demand driving this growth, including rising pipeline exports to Mexico, rising demand from power generation (gas taking share back from coal) and slightly higher LNG exports.

Looking out further, the low US gas price has stimulated various initiatives that are likely have an increasingly material impact on demand as we move through to the end of the decade. The most significant is the group of LNG export terminals in the US, many of which are still in the construction stages but will come online in 2019 and 2020. The table below shows the scheduled start-up of terminals, with 5.7 Bcf/day of capacity coming in 2019 – inevitably, some of this will be delayed into 2020.

Terminal	Location	2015	2016	2017	2018E	2019E	2020E
Cameron 1-2	LA					1.2	
Cameron 3	LA					0.6	
Corpus Christi 1-2	TX					1.5	
Cove Point 1	MD			0.8			
Elba Island 1-6	GA				0.3		
Elba Island 7-10	GA					0.2	
Sabine Pass 1-2	LA						
Sabine Pass 3-4	LA	0.1	1.0	1.2			
Sabine Pass 5	LA					0.7	
Freeport 1	TX					0.5	
Freeport 2-3	TX					1.0	
Incremental LNG exports		**0.1**	**1.0**	**2.0**	**0.3**	**5.7**	**0.0**
Total US LNG exports		**0.1**	**1.1**	**3.1**	**3.4**	**9.1**	**9.1**

Source: EIA; Simmons

Industrial demand will also grow thanks to the increased use of gas in the oil refining process and the construction of new petrochemical plants: Dow Chemical and Chevron Phillips have started up a large new Gulf Coast facility this year, the first new cracker to be built in the US since 2001.

We also believe that gas will continue to take the majority of incremental power generation growth in the US and continue to take market share from coal. Coal fired power generation closures have been a feature as new pollution standards have come into force in an effort to reduce mercury and acid gases emissions, which likely accelerates the switch to gas. Our working assumption is for gas fired power generation to grow 0.8-1.2 Bcf/day per year, although this will be affected by actual gas prices.

US gas supply

Overall, whilst gas demand in the US has been strong over the past five years, it has been overshadowed by a rise in onshore supply, pulling the gas price lower.

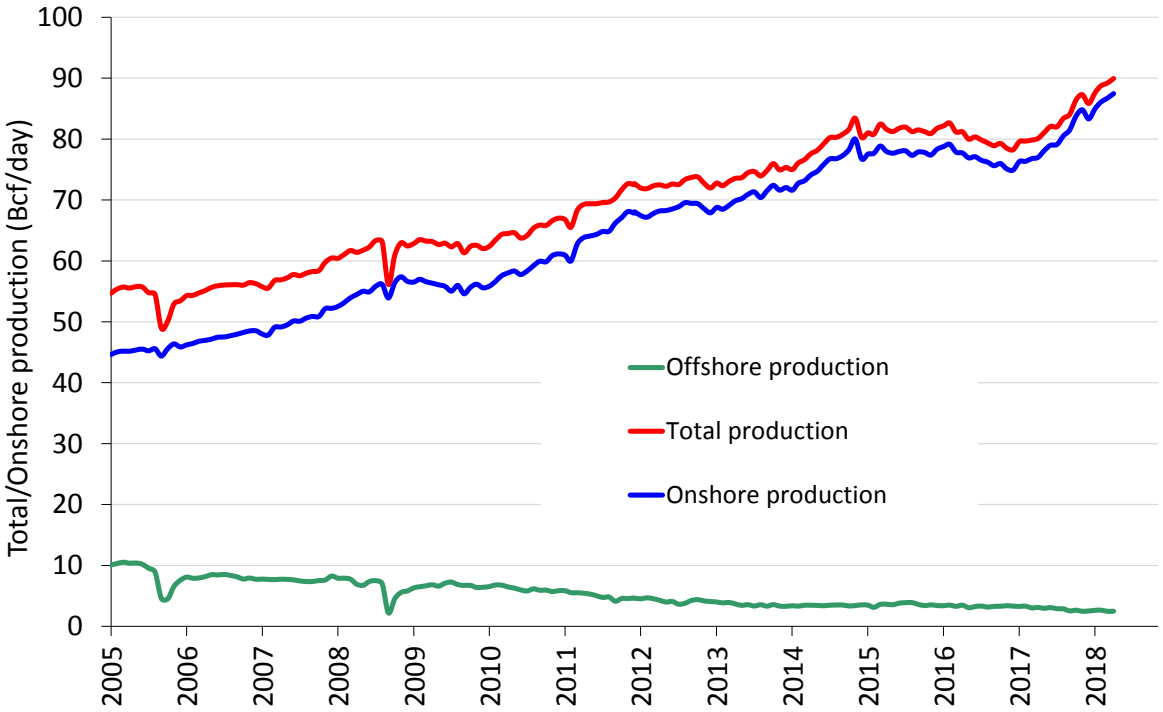
The supply side fundamentals for natural gas in the US are driven by 3 main moving parts: onshore and offshore domestic production, and pipeline imports of gas from Canada. Of these, onshore supply is the biggest component, making up over 85% of total supply.

Bcf/day	2007	2008	*2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018E
US natural gas supply:												
US onshore	45.1	48.8	49.8	52.2	57.7	61.5	62.7	67.5	70.6	69.4	70.4	77.3
US offshore (Gulf of Mexico)	7.7	6.3	6.7	6.2	5.0	4.2	3.6	3.4	3.6	3.4	3.2	3.2
Pipeline imports (Canada)	10.4	9.8	9.0	9.0	8.5	8.0	7.5	7.1	7.1	8.0	8.0	8.0
LNG imports & other	2.3	1.2	1.4	1.4	1.0	0.8	0.6	0.5	0.5	0.4	0.3	0.4
Total supply	**65.5**	**66.1**	**66.9**	**68.8**	**72.2**	**74.5**	**74.4**	**78.5**	**81.8**	**81.2**	**81.9**	**88.9**
Supply growth	**3.2**	**0.6**	**0.8**	**1.9**	**3.4**	**2.3**	**- 0.1**	**4.1**	**3.3**	**- 0.6**	**0.7**	**7.0**

Source: EIA; Simmons; Guinness estimates

Since the middle of 2008 the weaker gas price in the US reflects growing onshore US production driven by rising shale gas and associated gas production (a by-product of growing onshore US oil production). Interestingly, the overall rise in onshore production has come despite a collapse in the number of rigs drilling for gas, which has dropped from a 1,606 peak in September 2008 to only 81 in September 2016 and now 186 at the end of July 2018. However, offsetting the fall, the average productivity per rig has risen dramatically as producers focus their attention on the most prolific shale basins, whilst associated gas from oil production has grown handsomely. Onshore gas supply (gross, before processing) is now at 86.6 Bcf/day, 29.2 Bcf/day (over 50%) above the 57.4 Bcf/d peak in November 2008 before the rig count collapsed.

Figure 10: US natural gross gas production 2005 – 2018 (Lower 48 States)



Source: EIA 914 data (May 2018 published in August 2018)

Supply outlook

The outlook for gas production in the US depends on three key factors: the rise of associated gas (gas produced from wells classified as oil wells); expansion of the newer shale basins, principally the Marcellus/Utica, and the decline profile of legacy gas fields.

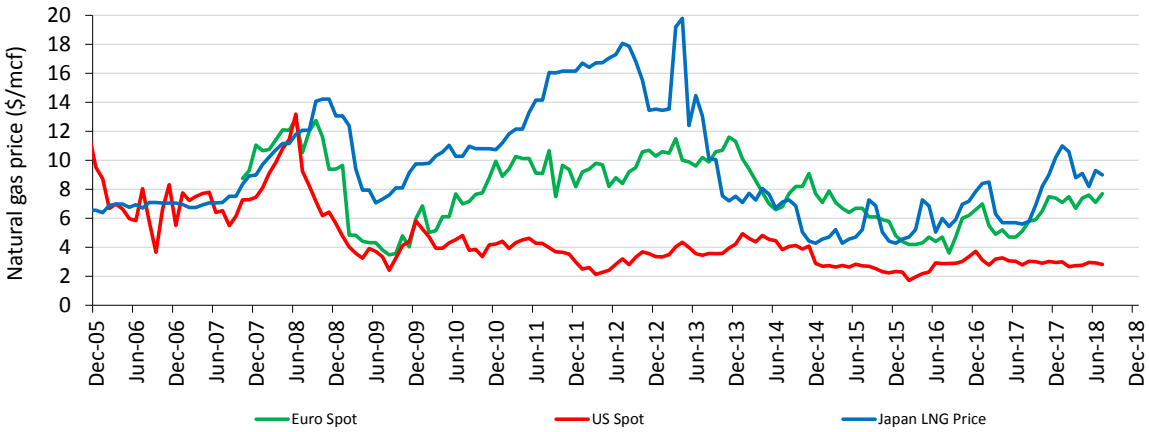
Associated gas production declined in 2016 with the fall of shale oil production, but as US oil supply now growing again, so associated gas production is also picking up. Generally, we expect to see rates of around 2-3 Bcf/day of associated gas per 1m b/day of oil production.

The Marcellus/Utica region, which includes the largest producing gas field in the US and the surrounding region, reached production of around 17 Bcf/day in 2016, though growth has recently slowed. Further growth is likely over the next couple of years, but only if local price differentials improve from the extreme levels seen in 2016. Then there is an expected decline in legacy gas fields, particularly if the gas drilling rig count stays low.

Overall, if the price remains in the $2.50-$3.50/mcf range, we expect a significant jump in onshore gas supply in 2018, up by around 7 Bcf/day versus 2017.

Outlook for US LNG exports – global gas arbitrage

The prospects for US LNG exports depend on the differentials to European and Asian gas prices, and whether the economic incentive exists to carry out the trade. The UK national balancing point (NBP) gas price – which serves as a proxy to the European traded gas price – remains at a premium to the US gas price (c.$7/mcf versus c.$3/mcf). Asian spot LNG prices fell sharply down to around $4.50/mcf at the start of 2016 but have since recovered to around $9/mcf as Chinese gas demand strengthens. The implied economics are tight at these levels into Europe, better into Asia, but sufficient to expect exports to proceed.



Source: Bloomberg (August 2018)

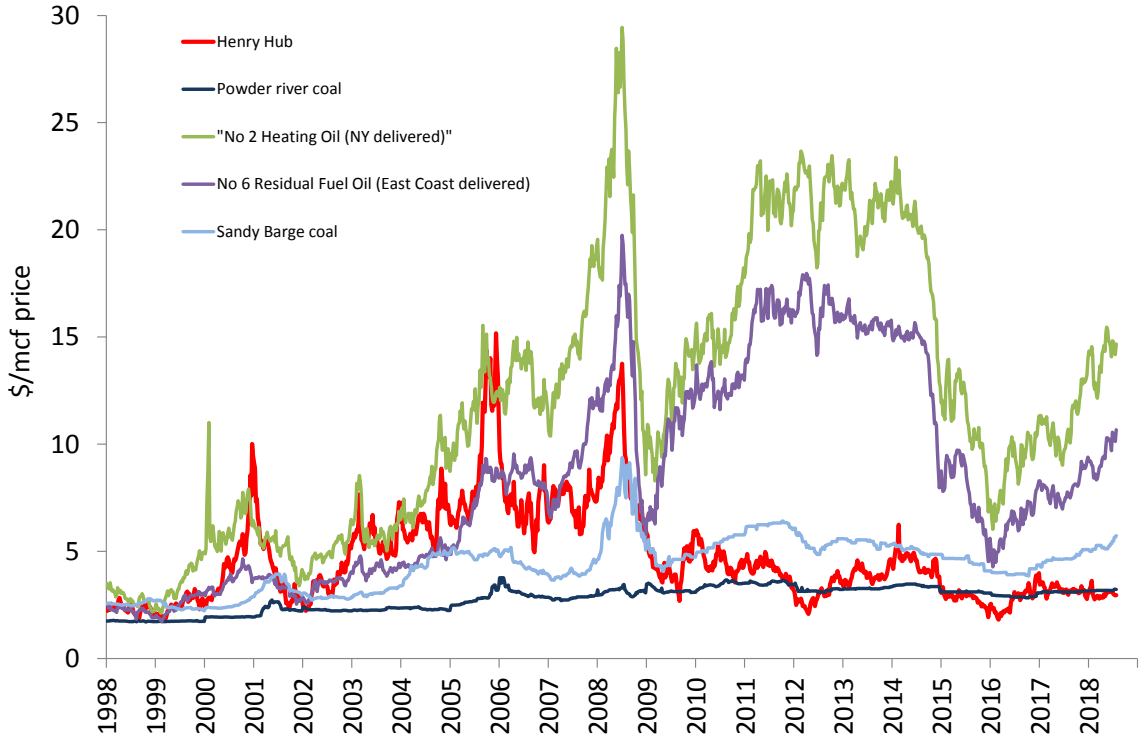
Relationship with oil and coal

The oil/gas price ratio ($ per bbl WTI/$ per mcf Henry Hub) of around 24x at the end of July 2018 continues well outside 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 11: Natural gas versus substitutes (fuel oil and coal)

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



Source: Bloomberg (July 2018)

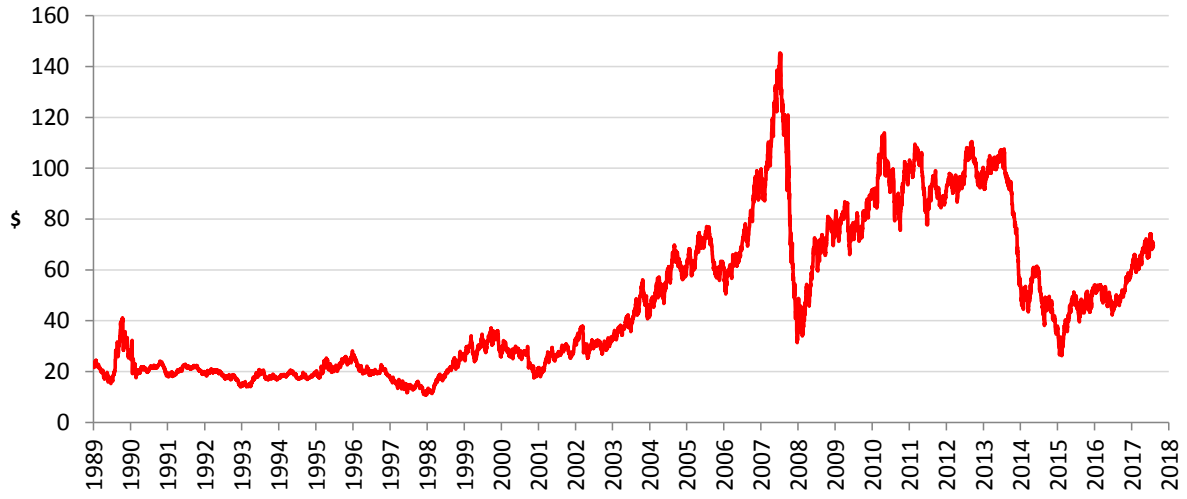
Conclusions about US natural gas

Bcf/day	2007	2008	*2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018E
Total demand	65.4	66.2	65.6	68.8	71.3	74.3	76.1	77.0	80.0	82.6	83.1	87.6
Demand growth	4.0	0.8	- 0.6	3.2	2.5	3.0	1.8	0.9	3.0	2.6	0.5	4.5
Total supply	65.5	66.1	66.9	68.8	72.2	74.5	74.4	78.5	81.8	81.2	81.9	88.9
Supply growth	3.2	0.6	0.8	1.9	3.4	2.3	- 0.1	4.1	3.3	- 0.6	0.7	7.0
(Supply)/demand balance	- 0.1	0.1	- 1.3	-	- 0.9	- 0.2	1.7	- 1.5	- 1.8	1.4	1.2	- 1.3

The US natural gas price bottomed in 2012 and a tepid recovery since then has been muted by continued strength in gas supply, particularly from the Marcellus/Utica and from gas produced as a by-product of shale oil. Average 2016 natural gas prices (at $2.55) were around 50% higher the April 2012 low, though we suspect that the (full cycle) marginal cost of supply remains above $3.50. We do not believe the excess in production over demand can continue indefinitely with natural gas trading at this level: a combination of reduced capital spending by the producing companies and growing natural gas demand stimulated by the low gas price will create a new market equilibrium. As this all happens we expect the price to stabilise in the $2.75 – $3.25/mcf range. It may be held at this level for a period until demand grows further, and longer term we expect the price to normalise to the top end of this range.

3. APPENDIX Oil and gas markets historical context

Figure 12: Oil price (WTI $) since 1989.



Source: Bloomberg LP

For the oil market, the period since the Iraq Kuwait war (1990/91) can be divided into two distinct periods: the first 9-year period was broadly characterized by decline. The oil price steadily weakened 1991 - 1993, rallied between 1994 –1996, and then sold off sharply, to test 20 year lows in late 1998. This latter decline was partly induced by a sharp contraction in demand growth from Asia, associated with the Asian crisis, partly by a rapid recovery in Iraq exports after the UN Oil for food deal, and partly by a perceived lack of discipline at OPEC in coping with these developments.

The last 13 years, by contrast, have seen a much stronger price and upward trend. There was a very strong rally between 1999 and 2000 as OPEC implemented 4m b/day of production cuts. It was followed by a period of weakness caused by the rollback of these cuts, coinciding with the world economic slowdown, which reduced demand growth and a recovery in Russian exports from depressed levels in the mid 90's that increased supply. OPEC responded rapidly to this during 2001 and reintroduced production cuts that stabilized the market relatively quickly by the end of 2001.

Then, in late 2002 early 2003, war in Iraq and a general strike in Venezuela caused the price to spike upward. This was quickly followed by a sharp sell-off due to the swift capture of Iraq's Southern oil fields by Allied Forces and expectation that they would win easily. Then higher prices were generated when the anticipated recovery in Iraq production was slow to materialise. This was in mid to end 2003 followed by a much more normal phase with positive factors (China demand; Venezuelan production difficulties; strong world economy) balanced against negative ones (Iraq back to 2.5 m b/day; 2Q seasonal demand weakness) with stock levels and speculative activity needing to be monitored closely. OPEC's management skills appeared likely to be the critical determinant in this environment.

By mid-2004 the market had become unsettled by the deteriorating security situation in Iraq and Saudi Arabia and increasingly impressed by the regular upgrades in IEA forecasts of near record world oil demand growth in 2004 caused by a triple demand shock from strong demand simultaneously from China; the developed world (esp. USA) and Asia ex China. Higher production by OPEC has been one response and there was for a period some worry that this, if not curbed, together with demand and supply responses to higher prices, would cause an oil price sell off. Offsetting this has been an opposite worry that non-OPEC production could be within a decade of peaking; a growing view that OPEC would defend $50 oil vigorously; upwards pressure on inventory

levels from a move from JIT (just in time) to JIC (just in case); and pressure on futures markets from commodity fund investors.

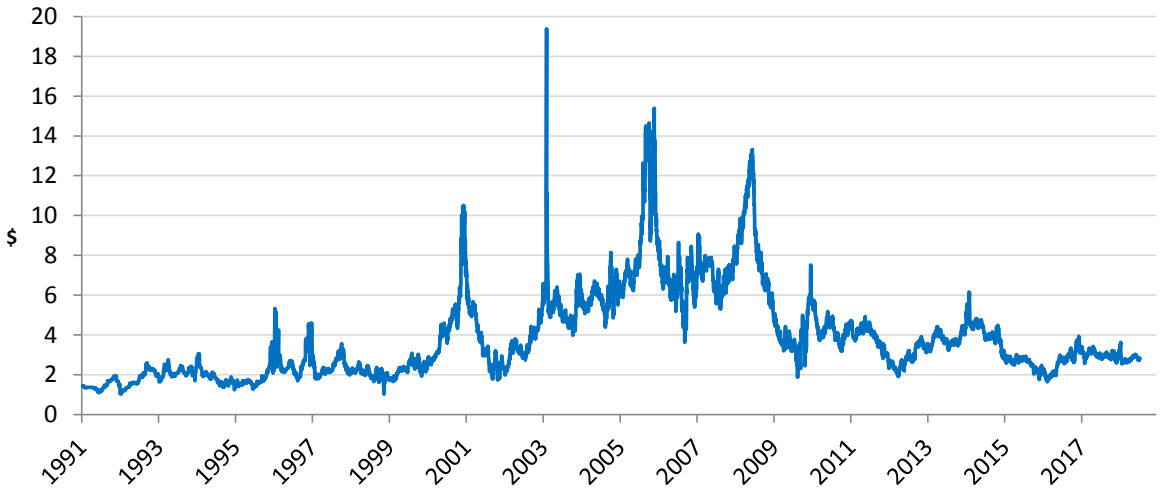
After 2005 we saw a further strong run-up in the oil price. Hurricanes Katrina and Rita, which devastated New Orleans, caused oil to spike up to $70 in August 2005, and it spiked up again in July 2006 to $78 after a three week conflict between Israel and Lebanon threatened supply from the Middle East. OPEC implemented cuts in late 2006 and early 2007 of 1.7 million barrels per day to defend $50 oil and with non-OPEC supply growth at best anaemic demonstrated that it could to act a price-setter in the market at least so far as putting a floor under it.

Continued expectations of a supply crunch by the end of the decade, coupled with increased speculative activity in oil markets, contributed to the oil price surging past $90 in the final months of 2007 and as high as $147 by the middle of 2008. This spike was brought to an abrupt end by the collapse of Lehman Brothers and the financial crisis and recession that followed, all of which contributed to the oil price falling back by early 2009 to just above $30. OPEC's responded decisively and reduced output, helping the price to recover in 2009 and stabilise in the $70-95 range where it remained for two years.

Prices during 2011-2014 moved higher, averaging around $100, though WTI generally traded lower than Brent oil benchmarks due to US domestic oversupply affecting WTI. During this period, US unconventional oil supply grew strongly, but was offset by the pressures of rising non-OECD demand and supply tensions in the Middle East/North Africa.

Most recently, since the end of 2014, Brent and WTI have dropped well below these trading ranges, as OPEC made clear their intention not to support the price, leaving the market oversupplied. Oil prices found a bottom in 2016 as a result of OPEC cutting production again, but remains capped for the timebeing by US onshore shale supply.

Figure 13: 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 because the infrastructure to export LNG from North America is not yet in place.

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