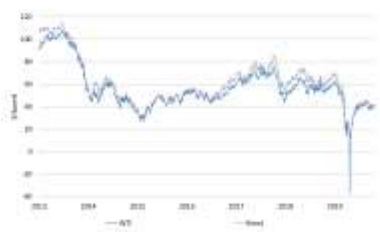
NATURAL RESOURCES

October 2020

OIL & GAS

BRENT VS WTI



	1m	3m	12m
—Brent $/bbl	-2.1%	-4.6%	-31.1%

Source: EIA

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EQUITY RESEARCH

OIL & GAS MACRO OUTLOOK

A vaccine is crucial

The covid-19 pandemic dealt an unprecedented hammer blow to oil demand in Q1 and Q2 of 2020. After being in an unprecedented surplus during this period, the market swung back to a substantial deficit in Q3. This was driven by the success of the OPEC+ production cutback programme, a throttling back of output in North America and a strong recovery in demand in China and to a lesser extent the US. Benchmark light crude prices have partially recovered from the ultra-depressed levels of the second quarter. The recovery, however lost momentum over the past three months as the covid crisis resurfaced, Libyan production came back on-stream and emerging fears of a reversal of OPEC+producer cutbacks in January. While we expect these factors to continue weighing on prices near-term, we see scope for a strengthening trend in 2021. The key catalyst is the likely release of a covid-19 vaccine by Q2 of 2021. This should gradually enable the economy to return to the semblance of normality along with oil demand. We also see OPEC+ deferring a roll back of production cuts if oil prices come under pressure in the coming weeks.

- **Supply/demand balance**: According to the EIA, the oil market was in surplus to the tune of 5.77mm b/d and 7.34mm b/d in Q1 and Q2 of 2020 respectively. The EIA's estimate for Q3 is a deficit of 3.07mm b/d and for Q4 is looking for a further shortfall of 2.96mm b/d. We believe the market in Q4 could be looser than indicated given less bullish demand than forecast related to recent covid policy initiatives. The EIA is calling for a supply deficit in 2021 of 0.26mm b/d.

- **Oil production:** Global oil production in 2020 looks like declining by about 6% based on EIA data. Non-OPEC production will probably be down around 3% while OPEC falls 12%. The decline in the former is mainly driven by the US, Canada and Russia. Helping buoy non-OPEC output in 2020 have been strong performances by Brazil, Norway and a first-time contribution from Guyana, the world's newest oil producer. The EIA is forecasting global production growth in 2021 of 4.3% driven by OPEC, as earlier cutbacks are rolled back and Libyan production returns to normal.

- **Oil demand**: Oil demand globally was down year-on-year by about 30% early in the second quarter of 2020 but for the full year the decline looks like being about 8.5%, according to the EIA. The OECD and non-OECD worlds will probably be off around 11% and 6% respectively. Significantly, demand in China could be up over 1% in the fourth quarter of 2020. Based on a global economic growth forecast of 5.3% the EIA is forecasting an increase in petroleum demand of around 6% in 2022. We are forecasting further gain of 3.5% in 2022 which would imply record global demand of 102.6mm b/d.

- **Peak demand**: In our view, petroleum demand is likely to continue growing through the decade of the 2020s, albeit at a slower pace than in recent years. We see peak oil arriving in the early 2030s at around 112mm b/d, implying a growth rate of about 0.7% pa from 2019. Demand is then expected to drift down to about 105mm b/d in 2035 and maybe 95mm b/d in 2040. Slowing growth followed by decline reflects vehicle electrification and public policy initiatives to curb fossil fuel usage. The energy transition still faces major technical and economic challenges and is likely to be a drawn-out process. There are no easy solutions.

- **Price forecasts**: Our new 2020 Brent and WTI price forecasts are $41.3/barrel and $38.6/barrel respectively. These constitute substantial downgrades compared with those given in February of $56.2/barrel and $51.8/barrel. The earlier forecasts had assumed that the covid epidemic in China would be contained there. Our forecasts for 2021 are $53.8/barrel for Brent and $51.3/barrel for WTI are predicated on a vaccine being widely available by Q2 and strong GDP growth of 5.0-5.5%. We expect prices to continue trending higher in 2022 as the market tightens. Our Brent and WTI forecasts for 2022 are $61.0/barrel and $58.5/barrel respectively.

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NOTE: EIA IN THIS REPORT REFERS TO ENERGY INFORMATION AGENCY, THE STATISTICAL ARM OF THE US DEPARTMENT OF ENERGY.

EXECUTIVE SUMMARY

Recent oil price developments: Benchmark light crude prices rebounded strongly from the historically depressed levels of April 2020. Brent rose from an April low of $9.1/barrel to a five-month high of $45/barrel in early August. WTI increased even more impressively between the April 20 low of -$37/barrel and the recent early August high of $42/barrel. Since August, the trend has been flat to slightly down with Brent and WTI trading at about $42/barrel and $40/barrel respectively in late October 2020 prior to the dip on the 28th. This took Brent and WTI down to $39.2/barrel and $37.4/barrel respectively. The initial rebound following the March/April dip was driven by a sharp tightening in the market reflecting the OPEC+ production programme, a throttling back of production in the US and Canada and a strong recovery in demand especially in China and to a lesser extent the US.

The price trend has softened over the past three months or so reflecting the resurgence of the covid crisis in Europe and the US and actual and potential supply pressures. On the supply front, key issues have been the resumption of production in Libya following a rapprochement between warring factions, fears concerning a potential rollback of OPEC cutback in January 2021 and signs of higher drilling activity in the US.

Brent-WTI spread: The Brent-WTI spread has narrowed significantly over the past year or so. Furthermore, in recent months the spread has traded within a tight range which contrasts with much of the past ten years when it has been volatile. The quarterly profile for the Brent-WTI spread in 2020 has been as follows: Q1 $4.7, Q2 $1.5, Q3 $2.1. In late October 2020 WTI was trading at a discount of about $1.8/barrel to Brent. This compares with an average discount in 2019 of $7.4/barrel.

The narrowing Brent-WTI spread in 2020 reflects two key factors. These are the relative buoyancy of North Sea production relative to that in the US Midcontinent and Texas and the upgrading of pipeline infrastructure from the Permian Basin and the Cushing tank farm to the Gulf Coast refineries and export facilities. In 2020 North Sea production has been broadly stable while US production in the four-weeks to October 23 in the Lower 48 states was down 16% YOY. The WTI discount in late October was slightly less than the pipeline tariff from Cushing to the Gulf Coast of $2.25/barrel. There was therefore no opportunity for profitable arbitrage by shipping to the Gulf Coast to capture Brent related prices.

Forward curves: The forward curves for both Brent and WTI are in contango (near month prices lower than for the more distant dates) for all dates through 2028. The contango is especially pronounced at the front end of the curves. The spread between December 2020 and 2021 was running at $2.73/barrel for Brent and $1.83/barrel for WTI for forward prices of $45.89/barrel and $43.53/respectively. The near term contango reflects the ready availability of supply particularly in the North Sea as the new Johan Sverdrup field has come on-stream. The resumption of Libyan production has also added to the availability of light crude on the eastern shore of the Atlantic basin. The middle and backend of the Brent and WTI forward curves are in moderate contango with terminal values in 2028 of $53.37/barrel and $49.15/barrel respectively. The moderate contango reflects market expectations of no major supply/demand imbalances in the years ahead.

Supply-demand balance: The oil market globally swung dramatically to an unprecedentedly large supply surplus in the first half of 2020. Based on EIA data, the surpluses were 5.77mm b/d and 7.34mm b/d respectively. There was a swing back to a sizeable deficit of 3.07mm b/d in the third quarter while in the fourth quarter a similar one of 2.96mm b/d is expected by the EIA. The average surplus for 2020 of 1.74mm b/d would be the highest for a single year since before the Asian financial crisis of the late 1990s. The previous high was 1.70mm b/d of 1998. The swing to deficit in the third quarter reflected a combination of the 9.7mm b/d OPEC+ production cutback programme, a throttling back of production in the US and Canada and a strong recovery in demand driven by China and a lesser extent North America. The fourth quarter supply deficit may need revising downward due to covid policy initiatives especially in Europe and signs of production gaining momentum.

For 2021 the EIA is looking for a tightening market reflecting a strong recovery in demand and lagging production growth. We forecast a further tightening in 2022 with a deficit of 0.61 mm b/d. The forecasts for both 2021 and 2022 are contingent on an efficacious covid vaccine becoming generally available by the second quarter of 2021.

Peak petroleum demand: In our view, petroleum demand is likely to continue growing through the decade of the 2020s, albeit at a slower pace than in recent years. We see growth averaging about 1.2% pa between 2019 and 2025 before slowing in the second half of the decade to about 0.5% pa. Peak demand is likely to arrive on our scenario in the early 2030s at about 112mm b/d before dipping away to perhaps about 105mm b/d in 2035 and 95mm b/d in 2040. This is in line with the scenario outlined in our December 2019 Oil & Gas Macro Outlook of December 2019.

We believe the key drivers behind slowing petroleum demand growth followed by a peaking out in the early 2030s and a decline thereafter will be vehicle electrification and public policy measures to curb fossil fuel usage. The energy transition from petroleum to electricity and non-petroleum-based materials will, in our view, be a drawn-out process. The petroleum industry dominates its principal markets in transportation and petrochemicals are widely used across manufacturing. Technical and economic drawbacks to the alternative technologies in the transportation field remain considerable.

Market thesis: During the fourth quarter of 2020 we look for benchmark light crude prices to trend flat to slightly down compared with the prior quarter. Keeping a lid on prices, we believe, will be lacklustre demand, particularly in the OECD world and a still sizeable inventory overhang. Countervailing influences helping support prices, we think, will be a market remaining in deficit and speculation regarding the availability of a covid vaccine in early 2021. Further support could be forthcoming in the closing weeks of 2020 from OPEC+ indicating a willingness to defer rolling back production cutbacks scheduled for early January 2021. In extremis we think OPEC+ might be prepared to intensify cutbacks.

We expect oil prices to trend higher in 2021 and 2022 buoyed by improving fundamentals as the covid crisis abates. However, we believe supply pressure particularly from OPEC will constrain any upward movement. A Biden Presidency, should it occur, is a wild card for both US domestic oil and gas production and internationally. A major issue internationally will be Joe Biden’s stance on sanctions on Iran and Venezuela.

Price forecasts: Our Brent and WTI forecasts for 2020 are $41.3/barrel and $38.6/barrel respectively. These constitute substantial downgrades compared with those given in February of $56.2 and $51.8/barrel. The earlier forecasts had assumed that the covid epidemic in China would not degenerate into a pandemic. Our forecasts for 2021 of $53.8/barrel for Brent and $51.3/barrel for WTI are predicated on a vaccine being widely available by the second quarter and strong GDP growth of 5.0-5.5%. We expect prices to continue trending higher in 2022 as the market tightens. Our Brent and WTI forecasts for 2022 are $61.0/barrel and $58.5/barrel respectively.

EXHIBIT 1: ENERGY PRICE SUMMARY

	Brent $/bbl	WTI $/bbl	Henry Hub $/mcf
2019	64.4	57.0	2.67
2020e	41.1	38.6	2.15
2021e	53.8	51.3	3.25
2022e	61.0	58.5	3.65

Source: EIA, Allenby Capital

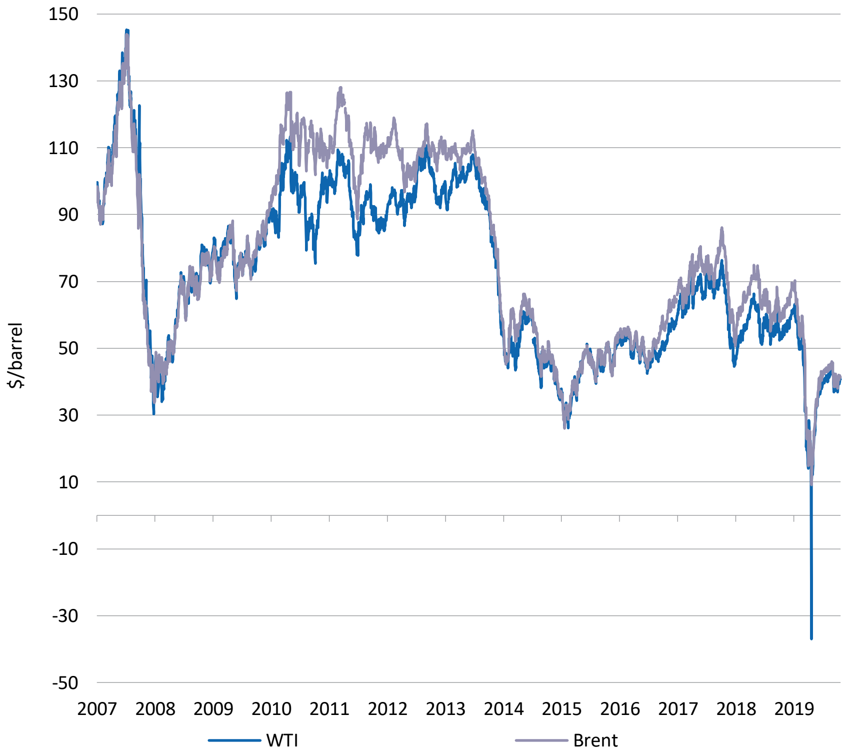
OIL & GAS MARKET 2020 YTD RETROSPECTIVE

PETROLEUM UPSTREAM

Plunge in prices to 22-year nominal low in April 2020-----: International oil prices in nominal terms plunged to an approximate 22-year low in April 2020. At the low point on the 21st Brent traded at $9.1/barrel. This was in line with the levels prevailing in December 1998 in the wake of the Asian financial crisis and substantially below the late 2008 financial crisis nominal low of about $34/barrel. Famously WTI, the US inland benchmark, plummeted to a negative $37/barrel on April 20. This, as far as we are aware, was an unprecedented event.

------from buoyant levels in early January: It should be remembered here that Brent had been trending up in late 2019 and on January 6, 2020 was trading at a seven-month high of $70.3/barrel. WTI had lagged Brent in late 2019 but nevertheless at $63.3/barrel on January 6 was also around a seven-month high.

EXHIBIT 2: LONG TERM BRENT VS WTI PRICE TRENDS ($/BARREL)



Source: EIA

The carryover strength in oil prices in early 2020 reflected several factors. These included the OPEC+production (the plus includes a wide range of non-OPEC producers of which Russia is by far the most important) accord struck in early December 2019, an easing of recessionary fears, falling exports Iranian and Venezuelan exports stemming from US trade and financial sanctions and heightened Middle East tension following the US assassination of General Soleimani and Abu-Mahandi. The former was commander of Iran's elite Revolutionary Guard Quds Force and the latter an Iraqi militia commander.

Prices started to come under pressure in February-----: The bullish trend in the early days of 2020 proved short-lived. Prices started to come under significant pressure in February with the downward trend intensifying in March. By end month Brent was trading at $14.9/barrel. The trend was essentially flat to slightly up through mid-April before collapsing on the 20th and 21st. The closing price for Brent on the 21st of $9.1/barrel was a massive 87% under the recent January high. WTI essentially sank into oblivion.

------as the market swung from approximate balance to hefty surplus: Downward pressure on Brent post the recent January 2020 high stemmed from a sudden swing from an approximately balanced market to a hefty supply surplus. Two factors were responsible. The first was a plunge in demand of a much as 30% as a result of the public policy response in many countries to the covid-19 pandemic and the second was the suspension by Saudi Arabia of the earlier OPEC+policy of production cutbacks. Rather than supply being trimmed in response to falling demand, it was boosted resulting in sharp inventory builds. The situation was particularly acute in the US where storage capacity was exhausted by April. The lack of storage capacity contributed directly to WTI descending into negative territory.

V-shaped recovery from April low: Contrasting with the late 1990s, the duration of ultra-depressed prices in 2020 was considerably shorter. This time around prices recovered in a V-shaped pattern through early August with Brent hitting around $45/barrel, a five-month high, on the 6th of the month. By early August WTI was trading at about $42/barrel. The rebound in Brent was driven principally by the following:

- The announcement in early April led by Saudi Arabia and Russia of a new policy of swingeing production cutbacks by the OPEC+group. This action was reinforced by Saudi Arabia implementing further voluntary cutbacks and by US and Canadian producers significantly reducing output due to poor profitability.
- A firming trend in demand as covid-19 related restrictions on economic activity were gradually eased.

Broadly flat trend since early August within a tight range: Since early August, oil prices have trended flat to slightly down around $42/barrel for Brent and $40/barrel for WTI within a tight range. On October 28 there was however a significant break-out to the downside with Brent dropping to $39.2/barrel and WTI to $37.4/barrel. These were around six-week lows. Despite the recovery post the April low prices have clearly remained significantly below the 2019 fourth quarter averages of $63.4/barrel for Brent and $57.0/barrel for WTI. A tightening market as reflected by falling inventories in the US, at least, has been sufficient to support prices at modestly profitable levels on a cash contribution basis. Uncertainty concerning the macro-economic picture along with market concerns relating to a potential influx of supply has constrained a break-out to the upside. The underlying issues on the demand side relate to the possibility of further covid-19 restrictions constraining economic activity and on the supply side stepped-up production by dissident members of the OPEC+group along with US shale oil and Canadian oil sands producers. The dip in prices on October 28 was very much covid-related.

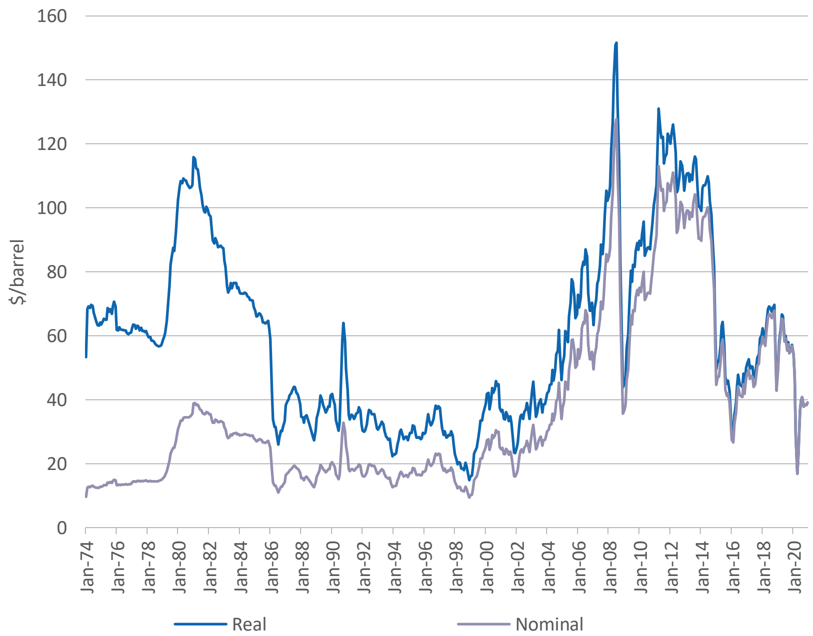
What does the trend look like in real terms?

In April Brent was at a more than 30-year low in real terms: To gain perspective on the oil price movements of the past year or so it is necessary to consult the statistical trend in real terms over an extended period. Based on EIA (Energy Information Administration the statistical arm of the US Department of Energy) prices for crude imported into the US were at the lowest level in real terms in April 2020 since at least early 1974. If we look specifically at Brent, which became the international oil price benchmark in 1987, the April 20, 2020 low was the lowest level in more than 30 years. In real terms the late 1998 nominal low of $9.4/barrel was equivalent to $14.7/barrel adjusted for US CPI inflation (August 2020 prices).

Prices in real terms back to the levels of early to mid-2000s: The recovery in Brent to the low $40s/barrel has broadly returned prices in real terms to the levels prevailing in the early to mid-2000s. Of course, prices currently even adjusted for inflation remain well below the recent highs in the third and fourth quarters of 2018 of broadly $65-69/barrel. Note, from an historical perspective over the past 45 years real prices much above $65/barrel have only tended to occur for relatively short periods as follows:

- Late 1973/early 1974; Yom Kippur war, Arab oil embargo, strong demand US production peaking.
- Late 1970s/early 1980s; Iranian revolution, strong demand.
- Fourth quarter 1990; Iraq invasion of Kuwait, preparation for a counterattack.
- 2007/first half of 2008; strong Asian demand and constrained supply.
- 2010-H1 2014; Overthrow of Coronel Gaddafi, Libyan output disruption, declining Saudi spare capacity and buoyant demand.

EXHIBIT 3: US IMPORTED CRUDE OIL PRICE TREND



Source: EIA

PETROLEUM DOWNSTREAM

Gasoline and diesel prices have rebounded from the April lows but remain depressed historically: Not surprisingly, refined product prices came under heavy pressure during March 2020 as demand plunged in response to covid-19 restrictions on economic activity and movement. Taking US Gulf Coast wholesale gasoline and diesel, prices slumped 66% and 30% respectively between end February and end March 2020. Wholesale prices for gasoline and diesel in March and April plumbed 20 or more-year lows of about $0.39/gallon and $0.54/gallon were at 20 or more-year lows. Subsequently, product prices have rebounded but remain depressed in the context of the past 15 years and are about 10% off the recent highs in July and August.

In late October 2020 US Gulf Coast wholesale gasoline and diesel prices were running at about $1.129/gallon and $1.108/gallon respectively. Compared with the March/April lows, the former was up by a hefty 3X while the latter was a less dramatic 2.0X. The rebound reflects rising refinery utilisation as demand has strengthened from the March April lows.

Crack spreads have widened from March/April lows but also remain depressed historically: Inevitably the plunge in product prices took its toll on refinery crack spreads in March and April 2020. At end March the Gulf Coast WTI 321 crack spread was a marginal $2.7/barrel. This was the gross refinery margin of converting three barrels of WTI into two barrels of gasoline and one of diesel at prevailing Gulf Coast wholesale prices. For perspective, the Gulf Coast 321 crack spread at end February was $16.9/barrel. By late October the spread had widened but only to about $6.4/barrel which implied distinctly marginal refinery profitability.

LNG PRICES

International LNG prices fell below $2/mm Btu in April----After plunging to unprecedently low levels in April 2020 international LNG prices have recovered strongly over the past three months or so. At the low point, the benchmark JKM (Japan/Korea Marker) spot price, according S&P Platts, was a mere $1.94/mm Btu cif East Asia and barely above the price of pipeline gas at the Henry Hub in Louisiana. In this context it should be remembered that the JKM hit an all-time high of $20/mm Btu in 2013 and 2014 and was running at over $5/mm Btu as recently as in late 2019. Note that the JKM was under heavy pressure in 2019 driven by a combination of burgeoning supply and weak demand stemming from mild weather conditions in east Asia, nuclear power generating capacity coming back on-stream in Japan, competition from renewables, slowing industrial activity and high gas inventories.

-------mainly reflecting covid-related influence in East Asia: During the first four or five months of 2020 the JKM came under further pressure due mainly to negative covid related influences on economic activity in East Asia. It should be noted that $2/mm Btu is a highly unprofitable LNG price bearing in mind the need to buy or produce pipeline gas and the costs of liquefication (for ease and safety of transportation) and cif (cost of insurance and freight). According to industry sources, profitable LNG operations require a premium of about $5/mm Btu over the cost of pipeline gas. In the case of US sourced LNG, this would imply a price presently of about $8.0/mm Btu cif, given a late October Henry Hub price of around $3/mm Btu.

Dramatic recovery in the JKM price to $6.7/mm Btu in late October: By late October 2020 the JKM was trading at $6.7/mm Btu, a dramatic rebound from the second quarter lows and a price which approaches fully accounted breakeven. The rebound in the JKM is partly seasonal given the approaching northern hemisphere winter but also reflects several other factors. These include a recovering trend in economic activity in East Asia, technical glitches and outages at Australian gas facilities and a firming trend of late in US natural gas prices. We also note that there has been a surge in North Sea gas prices recenty with the Dutch TTF benchmark, for example, rising from a 2020 second quarter low of $1.3/mm Btu to $5.18/mm Btu in late October.

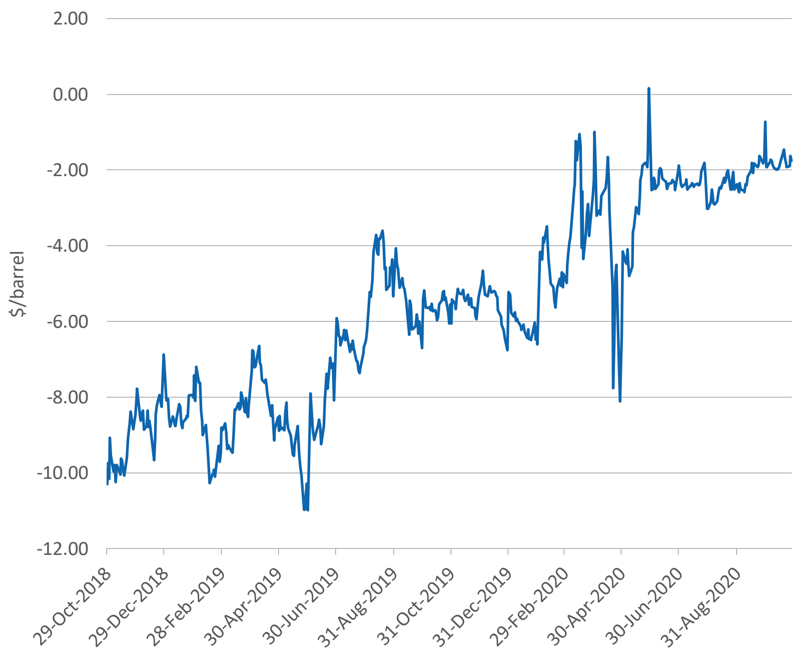
PRICE SPREADS

BRENT-WTI

WTI discount has narrowed sharply and is now about $2/barrel----: Brent and WTI are both high-grade light, sweet crudes with specifications of 37.5° API and 0.4% sulphur and 41.4° and 0.4% sulphur respectively. The Brent-WTI spread (WTI discount), the most influential of the light crude benchmarks, has narrowed significantly over the past year or so. Furthermore, since the second quarter of 2020 the spread has trended within a tight range. Looking at 2020 in the year-to-date the quarterly picture has been as follows: Q1 $4.7, Q2 $1.5 and Q3 $2.1. In late October 2020, the spread was $1.8/barrel. For perspective, the Brent-WTI spread averaged $7.4/barrel for 2019 as a whole and was running at a recent high of $9.2/barrel in the second quarter of the same year.

-----reflecting falling US production and upgraded infrastructure: The narrowing trend in the Brent-WTI spread in 2020 has been driven by two key factors. Firstly, production in Texas and the US Mid-continent has declined significantly since early in the year while North Sea output has trended flat to up supported by the giant Johan Sverdrup coming on-stream. Secondly, takeaway capacity from the WTI Cushing NYMEX settlement hub and from the Permian Basin to the Gulf Coast refining centres and export facilities now appears more than adequate. As of late October 2020, the Brent-WTI spread of around $2/barrel was slightly under spot pipeline tariffs for light oil from Cushing to the Houston area refinery complex of $2.25/barrel.

EXHIBIT 4: BRENT - WTI SPREAD ($/BARREL)



Source: EIA

WTI (CUSHING)-WTI MIDLAND SPREAD

Similar grades: WTI Cushing (Oklahoma) and WTI Midland (West Texas in the heart of the Permian Basin) are both light, low sulphur crude grades with similar API's (specific gravity or relative density). The specification for both grades is typically around 41° API and 0.40% sulphur. Historically, WTI Midland has sold at a discount of a dollar or two to WTI Cushing reflecting the relative remoteness of West Texas either to the refining centres of the Gulf Coast or the Cushing tank farm. In recent years prior to the opening of new export pipelines in the Permian, the Midland discount widened to as much as $10/barrel on occasion as production in the basin surged.

Upgraded pipeline capacity has enabled WTI Cushing-Midland spread to narrow: During 2020 the Midland discount has been running closer to the historical average and in late October was around $2.75/barrel. This was very similar to earlier in 2020 and indeed a year ago. Helping to narrow the discount over the past year or more has been a large increase in export pipeline capacity to the Gulf Coast and a lesser extent Cushing and declining Permian production in recent months. Rather than insufficient pipeline capacity, as was the case for several years prior to early 2020, there is now a significant surplus. According to industry sources, there is around 6mm b/d of export pipeline capacity in the Permian. This combined with perhaps 1mm b/d of inland refinery capacity in the Permian comfortably exceeds basin oil production of around 4.2mm b/d currently. As a result, pipeline tariffs have been coming under pressure and new pipeline projects reviewed for viability.

Permian producers can capture near Brent on Gulf Coast: Permian producers are still able to capture close to Brent prices by shipping oil to the Gulf Coast. LLS (Louisiana Light Sweet), for example, a popular light sweet grade on the Gulf Coast with a similar specification to WTI was selling for $41.28/barrel in late October 2020. This reflected a discount of $1.20/barrel to Brent and a premium of $3.4/barrel to WTI Midland which comfortably covers pipeline costs. For shipments from the Permian these are generally $2.50/barrel but in the case of the new EPIC Crude Pipeline are down to $1.35/barrel.

WILLISTON (BAKKEN) SWEET-WTI CUSHING SPREAD

One of the most remote basins: The Williston Basin in North Dakota and Montana accounts for about 11% of US oil production but is one of the most remote oil producing regions in the Lower 48 states. The crude sourced from the basin is generally high-grade with a light, low sulphur specification. Williston Sweet has an API of 42.3° and a sulphur content of 0.12%. It typically sells at a significant discount to WTI Cushing reflecting the distance of the Bakken from Midwest and Gulf Coast refining centres. Local refining capacity is modest in scale and consists of the Phillips 66 67,000 b/d Billings, Montana and the Marathon 75,000 b/d Mandan (Bismark), North Dakota facilities.

Williston Sweet discount to WTI has narrowed but still about $8/barrel: In late October 2020, Williston Sweet was selling for $32.3/barrel, a discount of $8.4/barrel to WTI Cushing. This was somewhat narrower than the $10-11/barrel of early 2020 and the discounts of $15/barrel plus on occasion in recent years. In common with WTI, Williston Sweet dropped to nominal or even negative levels in late April 2020. At the Clearbrook Minnesota hub, 450 miles east of Billings, Bakken light oil was selling for $37.5/barrel in late October 2020. This reflected a discount of $3.1/barrel to WTI Cushing. Shipment of Bakken oil to Clearbrook could however be $3-4/barrel spot.

Major legal disputes surrounding the Dakota Access and High Plains pipelines: A key issue of late for the Bakken producers has been legal disputes over export pipelines. Two pipelines, the 570,000 b/d Dakota Access covering the 1,200 miles from Stanley North Dakota to the Patoka Illinois tank farm (the second largest in the Mid-continent after Cushing) and the local High Plains pipeline serving the Mandan refinery have been threatened with closure in recent months. This follows lawsuits brought on environmental grounds by Indian tribal groups. The two pipelines account for about 50% of takeaway capacity in the Bakken presently. Permanent closures would entail relying much more on rail freight and trucking which would adversely impact logistical and field economics.

SWEET-SOUR SPREADS

BACKDROP

Historical sour discounts have on occasion narrowed or flipped to a premium in recent years: Due to the ease of refining into premium-priced products, light sweet grades, such as Brent and WTI, normally trade at a premium to sour-heavy grades. Unusually over the past two or three years historical sour discounts in the Atlantic Basin, Middle East and US Gulf Coast have tended to narrow or on occasion flip to a premium. This has reflected several factors. The key ones are probably the declining availability of sour crudes due to US sanctions on Iran and Venezuela, two major producers, OPEC+production cutbacks and falling production of the Gulf of Mexico Mars and Mexican Maya grades. It should be noted that in recent years Gulf Coast refineries have often been reconfigured to use what has historically been relatively low-cost heavy-sour feedstock. As it has happened, the reconfigurations have coincided with an influx of price advantaged light crude.

BRENT-URALS

Key sweet-sour spread: Within Europe the key sweet-sour benchmark spread is Brent-Urals. The latter is a Russian blended medium-sour grade using heavy and light-sweet crude which can be sourced either from Baltic or Black Sea ports. Urals has a sulphur content of 1.6% to 1.8% against 0.45% for Brent. Typically, it produces a much higher yield of HFO (heavy fuel oil) than Brent. By contrast, Brent and other sweet grades produce a much greater yield of high margin refined products. Historically, Brent has traded at a premium of $2-3/barrel to Urals.

Urals discount of $2.9/barrel normal in late October: Urals has tended to track Brent closely for most of 2020. The key exception was at the height of the covid crisis in April and May when for a short time there was a Brent premium of $10/barrel plus. In late October 2020 Urals was trading at $39.6/barrel a $2.9/barrel discount to Brent. So far, there has been little evidence of light low sulphur crude being given a boost reflecting the need to produce more MGO (marine gas oil) to enable ship operators to comply with new low sulphur emission regulations.

LOUISIANA LIGHT-MARS AND MAYA

Key Mars and Maya Gulf Coast sour benchmarks: The key US Gulf Coast sweet-sour benchmarks are LLS (Louisiana Light Sweet, St James hub)-Mars and LLS-Maya. Mars is a medium-grade crude with an API of 28° and a sulphur content of 1.8% sourced from the Gulf of Mexico, offshore Louisiana. It normally trades at a discount of a dollar or two to the higher-quality Louisiana Light Sweet which has an API of 37°and a sulphur content of only 0.37%. Maya is a heavy sour crude sourced from mainly from the Cantarell field offshore Mexico. It has an API of 21.8° and a sulphur content of 3.3%. Maya typically trades at a discount of $7-10/barrel to Louisiana Light.

Apparent tight supply of Mars: In recent months Mars has traded close to parity with LLS for much of the time but in early September 2020 moved to a premium of around $3/barrel. By early October, however, Mars had swung to a more typical discount of $1/barrel. The generally narrower variance between Mars and LLS combined with the swing to a Mars premium on occasion point to tight supplies for the sour grade. The situation of late has probably been exacerbated by hurricanes which disrupted offshore production from time to time in the third quarter.

Historically narrow Maya discount: During 2020 the Maya-LLS discount has been historically narrow. It has ranged between about $2/barrel and $5/barrel and in late October was running at $3.7/barrel. Abstracting from the unusual market conditions of April 2020, the recent peak for the discount was in August. Subsequently the discount has narrowed probably reflecting tight GOM (Gulf of Mexico) supplies of heavy-sour crude following hurricane activity and plentiful availability of light crude along the Gulf coast.

WCS-WTI SPREAD

Benchmark Alberta sour grade: WCS (Western Canadian Select) is a heavy, blended sour crude comprising a base of Alberta oil sands bitumen diluted with sweet, light synthetic crude and condensate. The API is 21° and the sulphur content 3.64%. This compares with 41°and 0.40% for WTI. Reflecting the specification differential and the remote sourcing, WCS has historically sold at a discount to WTI of $10-20/barrel. Analogous to heavy South American crudes along the Gulf Coast, WCS provides a useful source of price-advantaged crude for sophisticated refineries in the Midwest configured for processing heavy-sour feedstock.

WCS is also shipped via the existing Keystone XL pipeline to Cushing and the Gulf Coast refining complex which contains a heavy concentration of sophisticated facilities capable of handling heavy crude. Pipeline capacity via this circuitous route, however, constrains the flow.

Roughly $10/barrel discount to WTI in late October: WCS is typically one of the lowest priced crudes available. This remains the case. At the low point in April 2020 WCS was trading at about $4/barrel and in late October 2020 was at $30.1/barrel Hardisty, Alberta. The latter reflected discounts of about $10.5/barrel to WTI and $7.5/barrel to Maya which are within the historical range. Given pipeline tariffs, according to industry sources, of $7-9/barrel for the 2,200 miles from Edmonton Alberta to the Gulf Coast WCS clearly has the potential to be competitive with Maya and other heavy-sour crudes.

Alberta oil sands economics is better than the perception: The Alberta oil sands producers are often criticised, among other factors, for having unattractive production economics. The reality, however, is better than the perception. Suncor and Canadian Natural Resources, for example, the two largest oil sands producers put total enterprise cash operating costs, including sustaining capital, at between <$25 and around $30/barrel for WCS. Suncor, which is also an integrated producer of synthetic light crude with a specification similar to WTI, gives its breakeven price for this product including sustaining capital and the current dividend payment at circa $35/barrel. This compares with the late October price for Syncrude Sweet Premium of about $37/barrel. We also note that for most of the quarter ending September 2020 Syncrude was trading at nearer to $40/barrel.

ALBERTA PIPELINE STATUS:

Alberta needs new pipeline takeaway capacity for oil sands development: Alberta has significant downstream refining capacity at 477, OOO b/d or about 25% of the Canadian total. Although there may be scope to boost local refining and petrochemical capacity, development of the Alberta oil sands will be mainly dependent on expanding crude takeaway capacity. Enhanced economics will also necessitate better access to markets with higher prices. In practice this means access to export routes where international prices or high value US inland refinery prices can be captured.

Two major pipeline projects are stymied by legal, regulatory and political objections: Presently three major oil sands export pipeline projects are underway. Two however are stymied by legal, regulatory and political objections. These are the Keystone XL via a direct route from Hardisty Alberta to Steele City Nebraska and the Enbridge 3 Replacement from Hardisty to Superior Wisconsin. The former would connect the Alberta oil sands directly with the US Gulf Coast refining complex and will raise takeaway capacity by 900,000 b/d. The Enbridge 3 Upgrade involves a replacement of a 60-year old pipeline and would expand takeaway capacity by 370, 000 b/d.

Joe Biden has indicated his desire to veto Keystone XL: The Keystone XL pipeline is in use in Canada. It has also received US federal support and the approval of Nebraska's highest court. Legal objections by a group including environmentalists and Indian tribal interests have forced the operators to reapply for approval. Significantly, the Democrat Presidential nominee, Joe Biden, has indicated his desire to veto the project. It is very likely, in our view, that Keystone XL (Direct) will have to be abandoned in the event of a Joe Biden victory.

Enbridge 3 pipeline held-up in Minnesota: The 1,100-mile Enbridge 3 Replacement has been completed in Canada and Wisconsin and has been permitted for North Dakota. The remaining area of contention concerns the 335-mile section in Minnesota. Essentially there is a conflict between on the one hand environmentalists, Indian tribal interests and left-wing political groups and on the other economic interests, including local government, businesses and those seeking well paid employment. We believe the Enbridge 3 Replacement pipeline will ultimately be permitted. This is partly because it is a replacement for an existing increasingly frail pipeline, partly because the area of Minnesota in question has high unemployment and partly because of the obvious not insignificant economic advantages. Doubtless Joe Biden is hostile to the project but whether or not he would be willing to veto it at this late stage with all the ensuing chaos is an open question. Probably the earliest that an Enbridge 3 Replacement could come on-stream would be 2022.

Trans Mountain pipeline will provide access to Asian markets for first time----: The third Alberta oil sands export pipeline project under development is the 1,150km Trans Mountain from Edmonton, Alberta to Burnaby east of Vancouver, British Columbia. This involves twinning an existing pipeline between the two locations which will boost capacity from 300,000 b/d to 890,000 b/d. The new 590,000 b/d pipeline will ship heavy oil while the historical pipeline will concentrate on light products. Significantly, the Trans Mountain will give the Alberta oil sands access to Asian markets for the first time.

-------should come on-stream as scheduled by end 2022: The Trans Mountain project, originally owned by Kinder Morgan, was acquired by the federally owned Canada Development Corporation in August 2018. This followed a trade war between the Alberta and British Columbia provincial governments and interminable lawsuits brought by a variety of environmental and First Nations groups. Work on the pipeline recommenced earlier in the year and as of early September was 13% complete according to news reports. The Trans Mountain is scheduled for start-up by end 2022. Importantly, the completion of the Trans Mountain is not beholden to US election outcomes and furthermore being state owned is probably less susceptible to legal and political objections. The odds, therefore, are in favour of the Trans Mountain pipeline coming on-stream more or less as scheduled.

FORWARD CURVES

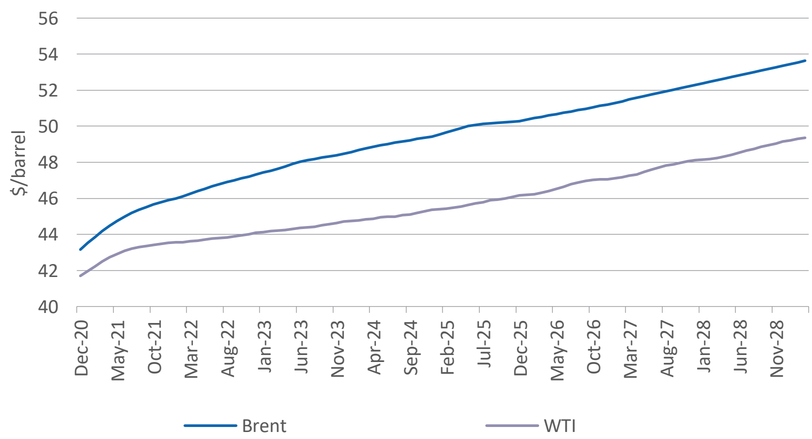
Brent and WTI forward curves have been in contango since late Q1 2020----The forward curves for both Brent and WTI are in contango (near month prices lower than for the more distant dates) for all dates through 2028. The contango is especially pronounced at the front end of the curves for both grades. In late October 2020 the spread between December 2020 and December 2021 was running at $2.73/barrel for Brent and $1.83/barrel for WTI. As of late October, the December 2021 forward prices for Brent and WTI were $45.89/barrel and $43.53/barrel respectively.

------reflecting the ready availability of near-term supplies: Contango has been a feature of the oil market since at least the onset of the covid crisis in late 2008 and reflects ready near-term availability. Supplies have been particularly plentiful of late on the eastern shore of the Atlantic Basin due to subdued underlying demand, refinery maintenance and buoyant North Sea production. The Brent one to three-month spread has recently traded at $1.02/barrel against $0.80/barrel for WTI. The milder contango for WTI than Brent possibly reflects disruptions to Gulf of Mexico operations caused by intense hurricane activity of late.

Moderate contango at the middle and back end of the curves: The middle and back end of the Brent and WTI forward curves reflect a moderate contango. Between December 2021 and December 2028, the forward spreads are $7.48/barrel for Brent and $5.62/barrel for WTI. This takes Brent to $53.37/barrel and WTI to $49.15/barrel at the termination of the curves. The moderate contango in the middle and back end of the curves suggests that market participants are expecting no major supply/demand imbalances in the out years. This is consistent with current consensus views of a supply overhang and sluggish demand related to the backwash of the covid crisis and possibly prospective electrification trends in the transportation sector. Views on these matters can, however, change very rapidly.

Curves generally point to modest profitability on new projects but some cases shale projects have breakevens significantly below $40/barrel: Both curves in the middle and at the back ends point to only modest profitability for development projects positioned around the mid-point on the cost curve. Typically, offshore conventional oil projects occupying the middle ground have fully accounted costs in the range $40-50/barrel. Specifically, in the case of US shale projects fully accounted breakeven points can be less than $40/barrel in the more prolific basins. This of course is before allowing for any extra costs that a future President Biden might wish to burden the oil and gas industry.

EXHIBIT 5: BRENT AND WTI FORWARD CURVE ($/BARREL)



Source: Thomson Reuters

US SCENE

DRILLING ACTIVITY

Recent oil-directed trends

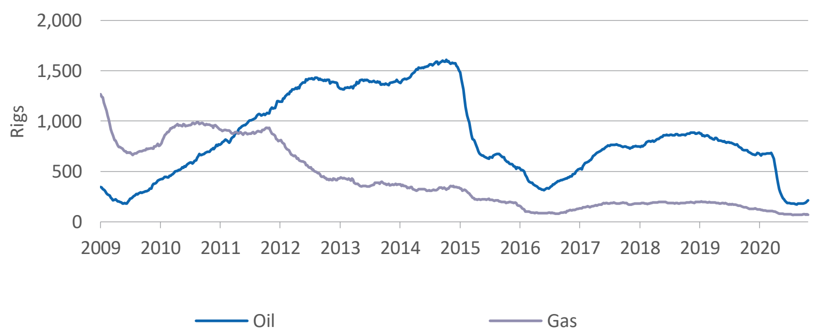
Rig-count sliding before the advent of covid-19: The US onshore oil-directed rig-count was sliding before the advent of the covid-19 crisis reflecting financially induced cutbacks in development activity across the tight reservoir basins of the Great Plains and Texas. Publicly traded junior and mid-tier E&P's during 2019 increasingly became subject to financial constraints and pressure from shareholders to boost returns and cash flow. A further problem for oil producers over the past year or two has been the emerging issue of falling well productivity in intensively drilled zones. Given very high decline rates of 50-60% after one year in typical tight reservoir wells reduced drilling activity rapidly flows through to production rates and therefore cash flow.

Precipitous decline post February -----The collapse in oil prices post February converted a slide into a precipitous decline in drilling over the following five months. At the recent low on August 8 the US oil-directed rig count of 172 was down 81% on the November 16, 2018 high of 888. Compared with the high in recent years of 1,609 in October 2014, the August low was off by 89%. Quite simply, at the prices prevailing in the second quarter of 2020 drilling could not be justified financially. The bulk of the wells that continued to be drilled in the second quarter probably reflected legal commitments. Interestingly, the oil-directed rig count at the August low was in line with that plumbed in June 2009 in the wake of the financial crisis.

--------but firming trend since August: Since August 2020 the US oil-directed rig count has firmed modestly and for the week ended October 23 came in at 211, up 23% on the recent low and a five-month high. The firming trend has slightly lagged the upward tendency in WTI since June/July and reflects two factors as follows:

- During the third quarter of 2020 WTI rose to around $40/barrel which very broadly corresponds to the fully accounted breakeven point in the more productive basins. It should also be noted that operational and well costs have fallen significantly over the past year based on anecdotal industry evidence.
- Bullishness in some quarters concerning the oil pricing outlook post 2020. This is driven by the expectation of strengthening fundamentals with the potential for a covid-19 vaccine becoming widely available during 2021 a key factor.

EXHIBIT 6: BAKER HUGHES US RIG COUNT (RIGS)



Source: Baker Hughes

Tight reservoir rig-count

Permian accounts for 63% of shale basin drilling: All the tight reservoir basins were impacted by the downdraft in drilling activity in the first half of 2020. This included the

Permian where at the July low the rig count was down to 116, a decline of 76% from the late 2018 high of 493. Since the low, the rig count in the Permian has firmed and for the week ending October 23 was 132, 63% of the US total. This compares with the 60% weighting at the beginning of 2020. The next largest contributors were the Williston (Bakken) and Eagle Ford with rig counts weightings of 6% and 8% respectively. The Niobrara basin in Colorado and the Cana Woodford in Oklahoma had weightings of 1% and 3% respectively while a group of miscellaneous basins accounted for about 19% of the total.

Recent gas-directed drilling trends

Gas-directed drilling remains subdued: Gas-directed drilling was running at historically depressed levels prior to the covid crisis reflecting highly unprofitable prices of sub \$2/mm Btu at key hubs such as the Henry Hub in Louisiana. The continuing downward trend in prices in the first half of 2020 to about \$1.5/mm Btu resulted in further cutbacks in drilling activity. By contrast, we believe fully accounted operating and development costs are closer to \$2.5/mm Btu. By late July 2020 the gas directed drilling rig count was 68, down 45% from end 2019 and 66% from the recent highs of 2018 and early 2019.

Gas directed drilling has shown few signs of significant firming in recent weeks with the rig count at 73 in the week to October 23. With gas prices showing a seasonally strong upward trend of late the scene is possibly being set for a recovery in gas drilling, although this maybe stymied if Joe Biden wins the presidency. Significantly, gas at the benchmark Henry Hub was trading in late October at around \$3/mm Btu, the highest price in about 18 months and importantly above fully accounted costs for gas-directed projects.

High profile bankruptcies including shale gas pioneer Chesapeake Energy: Highly unprofitable prices have resulted in a number of high-profile bankruptcies over the past year or so. This included in June 2020 Chesapeake Energy the pioneer of shale gas development in the US under the founder the late Aubrey McClendon and the one-time second largest producer of gas in the country. Another high-profile bankruptcy in 2020, albeit in the oil sector, has been Whiting Petroleum, one of the two leading producers in the Bakken. Significantly, however, Whiting quickly re-emerged from bankruptcy but with the bondholders in control of the equity.

PRODUCTION

Crude oil trends

March production peak of 13.1mm b/d-----: US crude oil production peaked in March 2020 at 13.05mm b/d, 8mm b/d higher than the 2008 multi-year low of 5mm b/d. The trend had been consistently upward from 2008 except for a brief dip in the second half of 2016. We believe it was unprecedented in the history of the petroleum industry in terms of strength and longevity for what was supposedly a very mature petroleum province. The key driver was the development of the tight reservoir basins of the Great Plains and Texas applying advanced horizontal drilling and multi-stage hydraulic fracturing technology. This technology had previously been applied to unlocking gas from tight reservoir formations. Contributing to the overall production gain was also a strong showing in the Gulf of Mexico.

-------followed by a sharp 21% drop to 10.3mm b/d in early September: Since peaking in March, crude production has declined sharply. The recent low at the beginning of September of 10.30mm b/d was 21% below March's peak. By contrast, the peak to trough dip in production during 2016 was 8%. The decline in oil production post the first quarter of 2020 was driven principally by a combination of rapidly falling drilling and well completion activity, well shut-ins and high rates of depletion. During Q3 hurricane activity also trimmed Gulf of Mexico production, although it had little or no impact onshore.

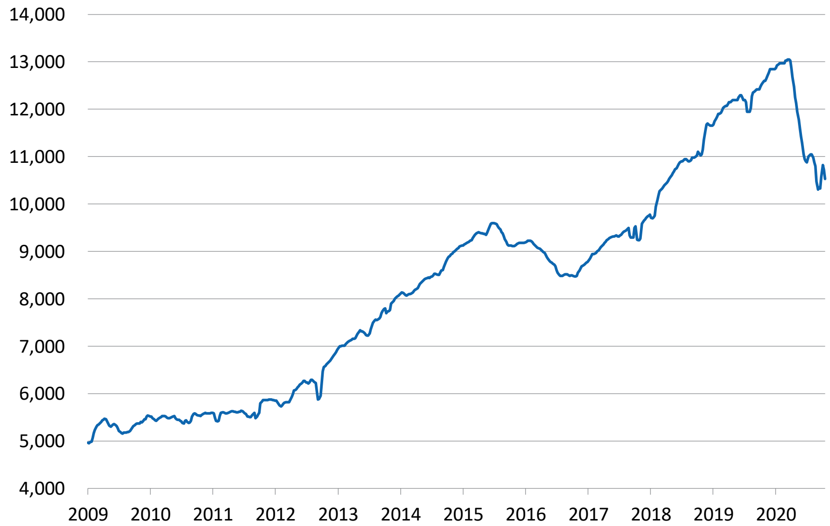
Production has edged higher since early September: Since the early September 2020 low crude production has edged higher and in the four weeks to October 16 averaged

10.53mm b/d, down 16.1% on a year earlier. We see the split of production (mm b/d) by province as follows: tight reservoir formations 7.81, conventional lower 48 0.29, GOM 1.60, Alaska 0.44, California 0.39.

Wells drilled and completed have fallen sharply since Q4 2019: Taking the tight reservoir basins of the Great Plains and Texas, EIA data shows wells drilled and completed in September 2020 at 295 and 372 respectively, down 72% and 69% on the 2019 fourth quarter averages. Both wells drilled and completed in September were close to at least around seven-year lows. Falling well completions were particularly significant given very high first year depletion rates in the tight reservoir formations of around 60%, according to industry sources. Reflecting the low rate of completions, the inventory of DUC's (drilled but uncompleted wells) has remained at a relatively high level in recent months and in August was 7,592, 2.6% down on end 2019. DUCs can be brought on-stream at relatively short notice providing fracking crews can be mobilised.

Production peak could be exceeded but will require significantly higher WTI and no regulatory obstacles: The key question now is the short to medium-term outlook for US crude production. Have we seen the peak, or will the March 2020 high be equalled or indeed exceeded over the coming year or two? The answer largely depends on the assumptions for the trend in WTI and hence drilling/completion activity remembering high rates of depletion. Assuming a firming trend in WTI to an average of around $45-50/barrel in 2021 and $55-60/barrel in 2022 we believe it is possible that the March 2020 peak could be equalled or exceeded in the latter. The EIA is forecasting US crude production to average 11.45mm b/d in 2020 and 11.09mm b/d in 2021 with 11.22mm b/d in the fourth quarter of the latter year. Its WTI forecasts are $38.8/barrel for 2020 and $44.7/barrel for 2021. Key areas of uncertainty relate to the availability of finance for drilling/completion activity, the well productivity issue mentioned earlier and the actions of a future President Biden, if he should come to power.

EXHIBIT 7: US CRUDE OIL PRODUCTION (B/D 000'S)



Source: EIA. Note: Data relate to four-week averages

Natural gas liquids and hydrocarbon substitutes

Substantial quantities of NGLs. The US produces substantial quantities of natural gas liquids (NGL's) and renewable fuels in the form of ethanol and biodiesel. In the case of NGLs, growth has trended strongly upward in recent years as a consequence of intensive oil-directed development activity particularly in the Permian Basin. The wells generate substantial quantities of by-product gas and NGLs. Wet gas production in basins such as the Appalachian and Haynesville also generate large NGL volumes.

Increasing NGL output in 2020 driven by ethane----: Interestingly, NGL production has trended higher in 2020. In the four-weeks to October 16 production averaged 5.28mm b/d, up 12.2% on a year earlier with the key factor being higher ethane output. This has been driven by rising domestic and export demand resulting in a firming price trend for the commodity. Rising domestic demand reflects new ethylene plants coming on-stream. Significantly ethane now sells at a premium to natural gas on an energy equivalent basis which encourages separation from the natural gas stream.

----- partly offset by ethanol and biodiesel: Contrasting with NGL's, production of hydrocarbon substitutes such as ethanol and biodiesel has slipped in 2020. For the four weeks ending October 16 production came in at 0.93 mm b/d, down 13.6% on a year ago. Taking NGL's, renewables and refinery processing gain, US production for the latest four-week period was a sizeable 7.08mm b/d, up 3.8% on a year previously. Overall, the output of hydrocarbon liquids plus renewables and refinery processing gain for the four-weeks to October 16 came in at 17.60mm b/d, down 9% on the comparable period in 2019.

Liquids forecasts

EIA forecasts -4% 2020 and +0.4% 2021 The EIA's forecasts call for overall US liquids production including refinery processing gain and renewables of 18.47mm b/d (-4.1%) in 2020 and 18.55mm b/d (+0.4%) in 2021. Clearly, these forecasts reflect significant downgrades compared with those given early in 2020 when the EIA was still looking for meaningful growth in both 2020 and 2021. Production for these two years was forecast at over 21mm b/d. In a global context, however, the decline in 2020 is modest thanks to the strong showing of NGL's driven by ethane. Assuming production of about 18.5mm b/d, the US will easily retain its title in 2020 as the world's largest producer of hydrocarbon and renewable liquids.

US self-sufficient in 2020 but possibly not in 2021: Looking at the issue of liquids self-sufficiency the US could achieve this status in 2020 but might fall slightly short in 2021 based on the EIA's production and consumption forecasts. The implied surplus of production over consumption in 2020 is modest at 0.24mm b/d but it would nevertheless be the first year that this status has been achieved in more than 50 years. For 2021 the EIA's forecasts imply a deficit of 1.42mm b/d reflecting broadly flat production and a strong 9.5% rebound in demand.

EXHIBIT 8: US CRUDE OIL QUARTERLY PRODUCTION

	Q1	Q2	Q3	Q4	Total
2018 mm b/d	10.25	10.52	11.25	11.82	10.96
YOY %	13.4	15.2	20.6	19.4	17.2
2019 mm b/d	11.83	12.13	12.25	12.78	12.25
YOY %	15.4	15.3	8.9	8.1	11.8
2020 mm b/d	12.75	10.82	11.02	11.22	11.45
YOY %	7.8	-10.8	-10.0	-12.2	-6.5
2021 mm b/d	11.07	11.00	11.05	11.22	11.09
YOY %	-13.2	1.7	0.3	0.0	-3.2

Source: EIA. Note: Data from Q3 2020 are estimates/forecasts.

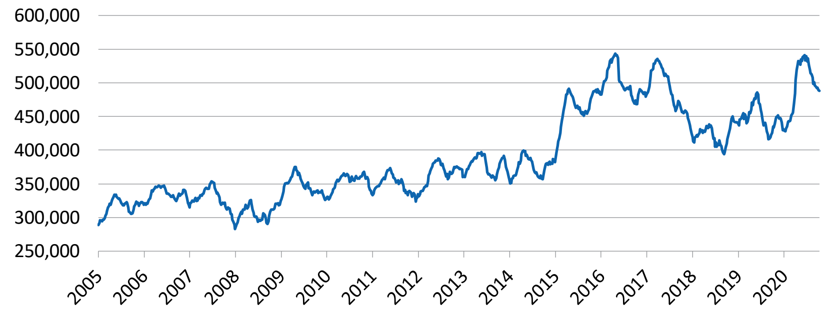
INVENTORIES

Crude

Crude oil inventories return to more normal levels: Not surprisingly, given the scale of the demand shock and the sharp decline in refining activity, US crude oil inventories surged in the first half of 2020 to virtually unprecedented levels both absolutely and in terms of days' supply. On both counts, however, inventories, although remaining historically high, have returned to more normal levels over the past three months. For the week ending October 16, 2020 commercial crude inventories stood at 488.1mm barrels, down 10% on the June 19 high of 540.7mm barrels and only modestly above the top end of the range for the time year. On a days' supply basis crude inventories were equivalent to 36.1 well down on the recent high of 41.9 reported at the beginning of May. For perspective at end December 2019 days' supply stood at 25.5.

Downward trend carrying over into 2021: The EIA's forecasts call for US crude inventories to dip to about 482mm barrels and 469mm barrels by end 2020 and 2021 respectively reflecting broadly flat supply and recovering domestic demand. On this scenario inventories should be close to the top of the seasonal range for the time of year for both 2020 and 2021.

EXHIBIT 9: US CRUDE OIL INVENTORIES (THOUSAND BARRELS)



Source: EIA

Cushing

Crude inventories spiked in May close to record levels-----: Cushing, Oklahoma is the location of the largest tank farm and oil trading hub in the US. Significantly, it is the settlement point for WTI on Nymex. Crude inventories at Cushing spiked at the beginning of the covid crisis reaching a high of 65.4mm barrels in early May 2020. This was about 30mm higher than in the first quarter of 2020 and approaching the all-time highs of about 69.5mm barrels recorded in the first half of 2017 when production was growing strongly in Texas and the Mid-continent and pipeline capacity to the Gulf Coast was severely constrained.

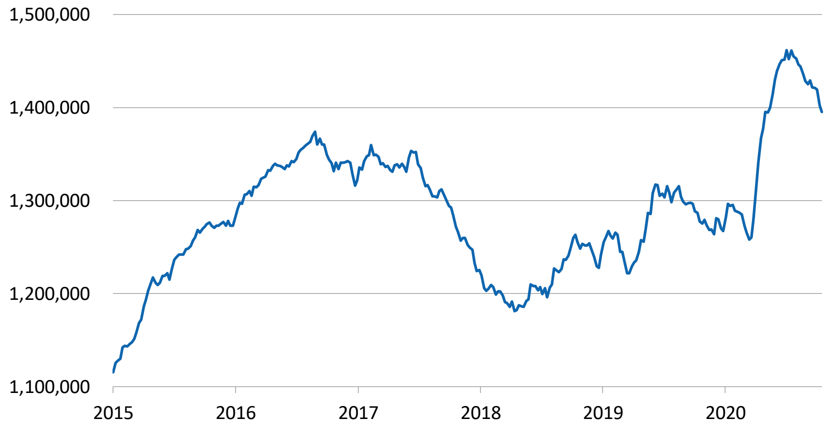
-------but quickly returned to more normal levels by end June: Working capacity at Cushing is about 76mm barrels, according to industry sources. Theoretically, therefore, there was still some headroom at the May 2020 inventory peak. The surge in inventories proved short-lived. By end June inventories had dropped at Cushing by 20m barrels to 45.6mm barrels. The decline reflected refineries and others opportunistically buying spot barrels at heavily depressed prices and sliding production in the Mid-continent and Texas. Since end June, inventories at Cushing have trended higher and on October 16, 2020 were 60mm barrels. This, however, is within the range over the past five or so years.

Given the expansion in pipeline capacity over the past few years taking oil from the Permian and Mid-continent to the Gulf Coast either for processing or export, we think it unlikely for the foreseeable future that Cushing spare capacity will become close to being exhausted.

Crude and product commercial inventories

Crude and product inventories surged to record levels in early July but subsequently dipped to more levels: Given fluctuations in refinery utilisation and crude oil and product imports and exports, the most insightful way of looking at inventories is on an all-encompassing basis, including both crude oil and refined product. Prior to the advent of the covid crisis broadly defined commercial petroleum inventories had been trending essentially flat at 1290mm barrels and significantly below peak levels of around 1372mm barrels recorded in 2016 and 2017. Inventories surged post the end of the first quarter and hit a recent high of 1462mm barrels in early July 2020. Subsequently the trend has dipped modestly and on October 16 stood at 1395mm barrels. This was equivalent 78 days' supply, still well up on the more normal 60 days at the beginning of 2020.

EXHIBIT 10: US COMMERCIAL OIL INVENTORIES (CRUDE AND PRODUCTS) (THOUSAND BARRELS)



Source: EIA

Gasoline

Normal for the time of year: US gasoline inventories at 250-260mm barrels were running towards the top end of the seasonal range early in the first quarter of 2020. The sharp drop in demand following the onset of the covid crisis resulted in a pronounced increase in inventories post April which took them well outside the seasonal range for the time of year. The upsurge, however, proved short-lived with inventories peaking at 263mm barrels on April 17. Subsequently the trend has been markedly downward as gasoline demand has strengthened due in part to seasonal influences and in part to firming economic activity. For the week ended October 16 gasoline inventories of 227mm barrels were in line with a year earlier and in the middle of the seasonal range for the time of year.

On a days' supply basis gasoline inventories on October 16 stood at 26.5 against 23.8 a year earlier. The latest days' supply was well within the historical range for the time of year.

Distillates

Slightly above the top end of the seasonal range: Contrary to gasoline, distillate inventories were at the low or even slightly under the low end of the seasonal range before the covid crisis struck. Inventories bottomed at 122mm barrels at the end of March 2020. During the second and early third quarters inventories rose powerfully seasonally and by May had easily exceeded the top end of the range for the time of year. The recent high for distillate inventories was 179.3 barrels in early September. This was slightly above the 176mm peak recorded in 2010 following the 2008/09 financial crisis. Partly for seasonal reasons, distillate inventories have dipped since early September and on October 16 stood at 160.7mm barrels which was slightly above the top end of the range for the time of year.

The distillate days' supply at 42.1 on October 16 was down from the recent high of 54.3 in early June but was still well above the 29.4 of a year ago. Current days' supply are high historically.

Propane and propylene

Propane is a gaseous hydrocarbon that is easily liquefied. The bulk of propane is produced as a by-product of natural gas production, but significant quantities are also derived from light crude and refinery gases. We believe significantly more than 50% of usage is fuel-related for space heating, cooking, drying, water heating, industrial vehicles and furnaces. The balance is mainly used to produce propylene, a precursor for producing a wide range of chemical resins, fibres, elastomers and other chemical products.

Propane inventories fluctuate sharply seasonally reflecting the use of the product as a fuel for space heating and drying, particularly in agriculture (crop drying is a major application). Sizeable quantities are also exported from the US. Typically, inventories increase in the third and early fourth quarters and run-off in the late fourth quarter and in the early first and second quarters.

Inventories roughly the same as a year earlier: US propane inventories have followed the typical seasonal pattern in 2020 but have tracked close to the high end of the seasonal range for the time of year. All told, propane has been less impacted than other hydrocarbon liquids by the covid crisis. On October 16 propane inventories stood at 98.3 mm barrels, up 3% from a year earlier. The days' supply for the most recent period were 88.9, slightly higher than the 88.1 of a year earlier.

NET TRADE BALANCE

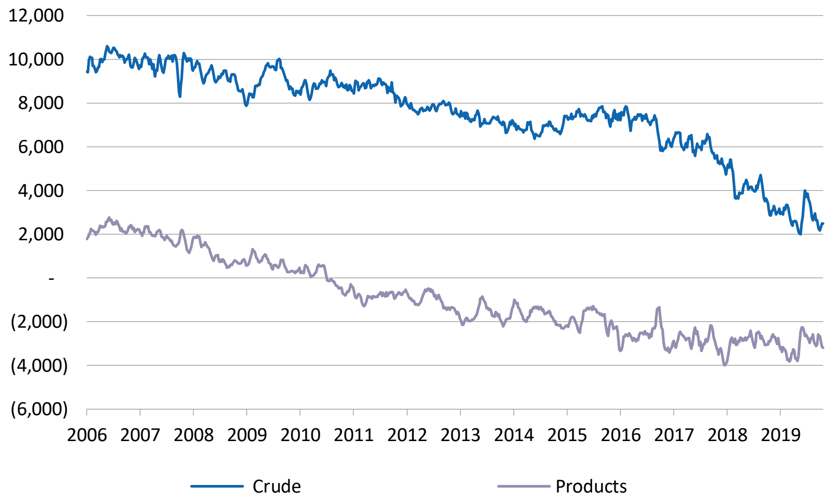
A trade surplus is in the cards for 2020----: The US flirted with a net trade surplus for petroleum products, including crude oil, in the closing weeks of 2019 and achieved this status more decisively in the first quarter of 2020. During the first quarter the surplus, based on EIA data, averaged 1.13mm b/d reflecting a deficit of 2.90mm b/d on crude oil and a hefty surplus of 4.03mm b/d on refined product. The widening surplus in the first quarter was driven principally by an increase in net product exports. In the second quarter the trade account swung to a modest deficit of 0.14mm b/d reflecting distortions associated with the covid crisis. The key factors were lower crude and product exports. There was a return to a surplus of 0.52mm b/d in the third quarter driven largely by lower net crude imports. Taking the four weeks to October 16 there was a trade surplus of 0.71mm b/d.

-----for the first time in at least 60 years: The EIA is looking for a US petroleum product surplus including crude in 2020 of 0.40mm b/d. This compares with a deficit of 0.67mm b/d in 2019 and one of 13.5mm b/d at the highwater mark in 2005. We believe that 2020 will be the first full-year surplus in at least sixty years. The key drivers behind the swing from hefty deficit to surplus over the past 15 years have been as follows:

- Surging US production of crude and NGLs which has sharply reduced imports and since the lifting of the embargo in 2015 boosted exports. This has been courtesy of the shale revolution.
- The competitiveness of the Gulf Coast refinery complex reflecting the availability of cost advantaged crude and natural gas and until 2020 very high facility utilisation vis-à-vis refineries elsewhere in the world.
- Proximity of Gulf Coast refinery complex to Latin American markets in general and Mexico in particular.
- Strong product demand in the Atlantic Basin outside Europe.
- Widespread outages and poor operating performance at refineries in Latin America. Particularly significant in this regard has been the atrophying of the once large-scale Venezuelan refinery infrastructure and the ongoing litany of operating problems at state-owned Pemex refineries in Mexico.

Sustaining a surplus will be difficult given the head winds some of which are political: The key question now concerns the sustainability of the swing to surplus on the petroleum trade account. Arguably the answer is not very sustainable reflecting, in particular, the anticipated drop near term in US crude and hydrocarbon liquids production and the likely less benign political backdrop facing the petroleum industry in the coming years. Of course, the trade balance will also depend on the strength of domestic demand. It is possible that demand will be weaker than generally expected which may enable exports and imports to balance at lower levels of production than has been the case of late. This, however, is not what the EIA has been forecasting for 2021. Its forecast for the year calls for a swing to a trade deficit of 0.87mm b/d driven by a widening in the crude deficit from 2.83mm b/d to 4.50mm b/d.

EXHIBIT 11: US CRUDE AND PRODUCT TRADE BALANCE – (000 B/D)



Source: EIA. Note: Negative balances are net exports.

DOMESTIC DEMAND

2020

Unprecedented drop in demand in April of 28%: US petroleum demand was moderately soft early in the first quarter of 2020 reflecting a mild winter and business slowdown. Based on EIA data demand for the quarter averaged 19.33mm b/d, down 5% on a year earlier. This moderate rate of decline was then followed by a collapse in April the likes of which had not been seen in the post-war era. Demand went from running at 20.2mm b/d in late March to 14.5 mm b/d at the low water mark in late April, a decline of 28%. By comparison, the peak to trough declines were about 19% and 16% at the time of the early 1980s recession and the Great Recession respectively. It should also be noted that the collapse of 2020 occurred over a considerably shorter timeframe than on the other two occasions.

All key petroleum products were impacted by the April downdraft. The two largest, gasoline and distillates, were off by around 40% and 30% respectively. Aviation fuel was particularly hard hit with demand down 75% at the low point in April. Petroleum demand was driven sharply down by widely implemented stay at home orders which rapidly lowered economic activity with the travel and transportation sectors particularly hard hit.

Strong initial recovery but trend has flattened over past two months: Since the late April lows, demand has recovered strongly although over the past month or two the trend has flattened and the level continues to lag a year ago. Taking the four-weeks ended October

16 demand overall came in at 18.31mm b/d, down 13% on a year earlier. All major product lines showed year-on-year declines as follows: gasoline -8.7%, distillates -9.5%, aviation fuel -40.2%, fuel oil -27.3%, propane -3.8% and miscellaneous -15.4%.

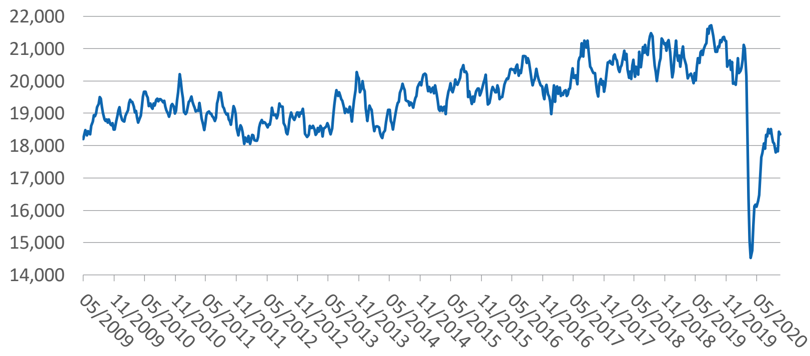
EIA forecasting a drop of 11% in 2020: The EIA is forecasting a solid trend in the closing months of the year. For the fourth quarter it is looking for demand of 19.21mm b/d, down 7% on a year earlier but up 5% on the third quarter and 19% on the second quarter. For 2020 as a whole the EIA's forecast calls for demand of 18.23 mm b/d, 11% under 2019 and the lowest level in more than 23 years. The forecast is based on real US GDP growth of -4.1% and an average retail gasoline price of $2.25/gallon (all grades), down 16% on 2019. Note, a key factor buoying US petroleum demand in 2020 is NGLS (natural gas liquids). According to the EIA, demand will be almost flat between 2019 and 2020 supported by strong demand for ethane related to rising ethylene cracking capacity.

2021

EIA forecasting strong 9.5% rebound in demand in 2021: The EIA is looking for US petroleum demand to return to the semblance of normality in 2021 as the covid crisis eases and the economy begins to recover lost ground. Its forecasts call for demand to increase by 9.5% to 19.97mm b/d. For the two largest product lines gasoline and diesel the EIA is forecasting growth of 9.1% to 8.97mm b/d and by 5.6% to 3.96mm b/d respectively. Interestingly, the EIA is also looking for an approximate 50% increase in aviation fuel usage to 1.54mm b/d. NGL's are expected by the EIA to be an area of strength in 2021 driven by rising ethane feedstock needs associated with further additions to ethylene cracker capacity.

The EIA's 2021 demand forecast reflects the assumptions of 3.5% GDP growth and an average retail gasoline price of $2.36/gallon. Clearly, the key issue for 2021 is how the covid crisis develops in the coming months and whether or not it abates. This in our view is highly dependent on the early and widespread availability of an effective vaccine. Arguably in these circumstances GDP growth could comfortably exceed 3.5% which would probably boost petroleum demand growth to well over 20mm b/d. Contra-wise, a lack of an effective widely available vaccine could severely constrain demand growth in 2021.

EXHIBIT 12: US PETROLEUM PRODUCT SUPPLIED (B/D '000)



Source: EIA. Note: Data relate to four-week averages

M&A ACTIVITY

Recent spate of M&A activity in US oil patch: M&A activity in the first half of 2020 in the US oil patch was more subdued than many petroleum industry observers expected given heavy pressure on profitability and heavily indebted balance sheets. This however has changed over the past three months or so following the announcement of four sizeable acquisitions/mergers. These involve Chevron and Houston-based Noble Energy, Devon Energy and Tulsa-based WPX Energy and ConocoPhillips and Midland-based Concho Resources and Pioneer Natural Resources and Austin-based Parsley Energy. Significantly, all four deals involved the acquisition of Permian assets and were paper deals. They were valued on an enterprise value (including the assumption of debt) basis as follows:

- Chevron-Noble Energy $12.1bn (share price movements reduced the value of the deal from $13bn at the time of the announcement in July).
- Devon Energy-WPX energy $5.7bn
- ConocoPhillips-Concho Resources $13.4bn
- Pioneer Natural Resources $7.6bn

All three deals have followed hefty share price declines from the first quarter highs of 50% or more and therefore should be considered opportune. They all reflected only modest share price premiums.

Other Permian mid-tiers now in play: Arguably all the mid-tier E&Ps and particularly those with a major position in the Permian Basin are now in play. In financial circles speculation has recently surrounded Diamondback Energy, a pure Permian play and one of the largest operators in the basin, as a potential takeover target.

Chevron-Noble Energy deal

Reserves obtained cheaply: Chevron's deal was announced in July and has now been consummated and followed its fortuitously abandoned bid to acquire Anadarko Petroleum in 2019. The inspiration for the deal with Noble was principally an opportunity to bulk up on high quality reserves and development potential at a low cost. Around 2.1 bn boe of proved reserves and almost 7m bn barrels of risked resources were acquired for $5.8/boe and under $1.5/boe respectively. All told, the Noble deal has increased Chevron's December 2019 proved reserves by 18% to 13.5 bn boe.

Significant boost to Permian/Delaware Basin presence: The principal areas where reserves have been added are in the Delaware (a sub basin of the Permian in Texas and New Mexico), Eagle Ford (Texas) and DJ Basins (Colorado) in the US and the Leviathan Tamar gas fields in the eastern Mediterranean. Chevron's production near term is scheduled to increase by about 13% to 3.5mm boe/d. The deal has significantly increased Chevron's US shale footprint with incremental production of about 0.27mm b/d. As a result, Chevron has now become the second largest producer of shale oil in the US, according to industry estimates.

Accretive to earnings within a year: Significantly, Chevron has indicated that the Noble deal will be accretive to earnings and cash flow within a year from being concluded. This partly reflects Chevron's anticipated near-term annualised operational and G&A cost savings of approximately $300m. For Noble the virtue of the merger with a far larger group was to lower risk bearing in mind an $8bn debt load.

Devon Energy-WPX Energy deal

Devon's planned merger with WPX merger with WPX Energy was announced in late September and is expected to be concluded in the first quarter of 2021. Based on WPX's end 2019 proved reserves of 528mm boe the merger terms implied an EV/boe of $10.8. Proved reserves, however, excluded the acquisition of privately held Felix Energy which was only concluded in the first quarter of 2020. The pro-forma price/boe was therefore in all likelihood significantly lower than indicated. The rationale for the Devon-WPX merger primarily reflected two objectives. These were leveraging the cost base of the two companies and boosting development potential in the Delaware Basin.

Acquisition of a major Delaware Basin play: Importantly, following the merger Devon-WPX will have in the Delaware Basin a net acreage position of 400,000 acres and proved reserves of 638mm boe based on end 2019 status. Across all basins pro-forma production is 277,000 b/d for oil and 532,000 boe for all products. In terms of acreage, pro-forma reserves and production Devon-WPX will evolve as one of leading operators in the Delaware Basin. Significantly, Devon-WPX is aiming for sizeable annualised cost savings across its operations of $575m by end 2021. Management is also aiming for an ultra-low cash cost breakeven point of $33/boe including maintenance capital spending.

Emphasis on cash flow, low leverage and dividends: Devon-WPX is very much in the vanguard of those operators stressing free cash flow, margins, dividends and low leverage rather than unconstrained production growth. The company is, in fact, going a stage further and aiming to pay a base quarterly dividend of $0.11/share and a variable pay-out equivalent to 50% of free cash flow. Pay-outs are, however, subject to the following caveats: a cash balance >$500m, 'strong balance sheet and low leverage ratios' and a 'constructive commodity price outlook'. On the leverage front, a key metric for Devon-WPX is the net debt-EBITDA ratio. The target is around 1.0X. This compares with a pro-forma 1.9X presently which according to Devon-WPX compares with slightly over 3X on average for its peer group.

ConocoPhillips-Concho Resources

Presence in the Permian/Midland/Delaware Basins substantially increased: ConocoPhillips merger with Concho was announced on October 19. The rationale for the deal is similar to the other two. It enables ConocoPhillips to gain a substantially greater presence in the two Permian sub basins, the Midland and Delaware. According to the Concho annual report, ConocoPhillips is buying a substantial 549,000 net acres with excellent development potential and 1bn boe of proved reserves. Based on the $12.9bn consideration ConocoPhillips is paying $13.4/boe. For Concho the attractions of the deal are the added security that stems from being part of a large well financed entity and a significant enhancement in yield from 1.7% to 5.2%.

Number three US shale producer: Production at Concho is running at about 200,000 boe/d net. According to the consultancy Wood McKenzie, the combined entity will have pro-forma shale production in 2020 of 465,000 boe/d making it the third largest US shale producer. In total, production will be around 1.5mm boe/d which will make ConocoPhillips the largest of the US independents on this metric.

The merger is expected to generate a hefty $500m in annual operating cost and capital savings by end 2022. This factor alone justifies a sizeable part of the acquisition cost. Significantly, ConocoPhillips points to the potentially low cost of supply for the combined group of under $40/barrel.

Pioneer Natural Resources-Parsley Energy

Pioneer obtains a leading presence in the Delaware and bulks up on its already dominant Midland position: Hard on the heels of ConocoPhillips, Pioneer announced its acquisition of Parsley Energy on October 20. Pioneer is the leading operator in the Midland Basin while Parsley, following the acquisition of Jagged Peak Energy, earlier in 2020, is focused on the Delaware Basin to the west but also has a sizeable presence in the Midland. Parsley has approximately 250,000 net acres and at the end of 2019 before the Jagged Peak acquisition reported proved reserves of 592mm boe. Pioneer's acquisition terms would suggest a price/boe of comfortably under $12.8. On a proforma basis the new entity will have over 1.7 bn boe of proved reserves and around 930,000 acres of land all in the Permian. Production is running at about 560,000 boe/d net.

The rationale for the acquisition of Parsley is threefold. It is partly to gain critical-mass relatively cheaply in the Permian Basin, partly to extract operating and financial synergies and partly to increase the inventory of high quality drilling opportunities. Significantly, Pioneer is looking to make synergistic savings as a result of the acquisition of an annualised $325m. Pioneer also suggests that the new entity will have a very attractive WTI breakeven including the base dividend in the mid-$30s. The company is also planning to pay a variable dividend. For Parsley shareholders there are advantages in being part of a larger group with a strong balance sheet and lower cost of capital and greater a dividend paying capability. Pioneer currently has a dividend yield of 2.63% against 1.88% for Parsley. The pro-forma net debt/EBITDA is around a modest 1.5X, one of the lowest multiples in Pioneer's peer group.

Major merger in Canada

Cenovus acquires Husky Energy in an all paper deal which values the latter at US10.6bn: The recent spate of M&A activity in the US oil patch was followed on October 26 by a major deal in Canada involving Cenovus acquiring Calgary-based Husky Energy. Including assumed debt, the deal values Husky at about C$10.6m (US$8.1m). Compared with the average price in the five days prior to the deal, Husky's stock is being acquired at a 21% premium, significantly higher than in the recent US deals.

Third largest oil producer based in Canada with a large refining presence in Canada and US: Following completion of the deal, the newly created Cenovus will be the third largest oil producer based in Canada after Canadian Natural Resources and Suncor. Upstream production will be approximately 770,000 b/d, the bulk of which will come from the Alberta oil sands. There will also be upstream E&P interests offshore Indonesia, Philippines and Newfoundland and in conventional fields in Alberta. Reserves on a combined 2P basis will be around 9mm boe. The new entity will also have substantial midstream and downstream capacity. Pro-forma refinery capacity will be around 700,000 b/d located in both Canada and the US. On a pro-forma basis, the new Cenovus will have an enterprise value of C$23.6m (US$18.0m).

Major presence in the Alberta oil sands including midstream and downstream: Cenovus currently has two producing oil sands assets at Christina Lake and Foster Creek producing around 345,000 b/d using steam assisted gravity (SAGD) technology. Husky adds critical mass to the combined unit's oil sands assets principally via its interests in the Sunrise bitumen, Tucker, Lloyd Thermal and Lloydminster upgrader and refinery complex. Significantly, Husky also brings to the party interests in three US refineries plus pipeline and storage facilities.

Upstream and refining interests now matched thereby eliminating exposure to the WCS-WTI discount: We believe the rationale for the merger is driven by the three key considerations. The first is the extraction of operating and capital spending synergies with the larger group. These are put at C$1.2bn at an annual rate, the bulk of which are expected to be realised in the first year following the merger. The second is to accelerate the pace of deleveraging with the aim of achieving a net debt to EBITDA multiple of <2.0X within two years. The third consideration is to roughly match upstream with downstream refining capacity thereby eliminating exposure to the WCS discount issue mentioned earlier. Unusually perhaps, Cenovus is pursuing the unfashionable concept of establishing an integrated oil business. We believe that given the endemic nature of the WCS discount, which on occasion can be substantial, that this makes sense strategically and financially.

US PRESIDENTIAL AND CONGRESSIONAL ELECTIONS

Most important election for oil and gas industry since its inception: The upcoming US Presidential and Congressional elections on November 3 are arguably the most important for the future of the oil and gas industry since its inception. Never in the post war period has the industry been under such a threat. Assuming the opinion polls are correct, and the Democrats capture the White House and quite possibly the Senate, the industry will be subject to a raft of taxes and regulations all designed to raise costs of operation, restrict output and ultimately cut hydrocarbons demand.

Biden Clean Energy Programme draws its inspiration from the Green New Deal: In addition to tighter regulations and additional taxes, a $1.7tr 'Clean' Energy Programme over ten years is planned by a prospective Biden administration. This draws its inspiration from the Green New Deal, a wide ranging programme of regulatory initiatives and economic policies supposedly to combat climate change and supported by a broad group of left wing Democrats. The Green New Deal has very much become associated with Rep Alexandria Ocasio-Cortez of New York who is one of the leading standard bearers of the Left in Democrat circles. In a formal sense Joe Biden does not support the Green New Deal as such.

Natural gas could be particularly vulnerable under the Biden programme. Among other objectives the Democrat's programme aims for an emissions-free power generation sector by 2035. Clearly, natural gas as the largest energy source for power generation, would be particularly vulnerable and could become the next coal. Democrat controlled California has also recently stated that it intends banning the sale of gasoline and diesel ICE (internal combustion engine) powered cars and light trucks from 2035 and would encourage other states to do the same. It is unclear whether California under a Democrat administration would also seek to ban diesel ICE medium and heavy trucks.

Potential drilling ban on federal land and offshore waters: So far, the details of the Democrats energy programme have not been revealed. It has however been intimated that the programme will involve, corporate tax changes, heavy spending on research and development into renewable energy solutions and subsidies aimed at encouraging the use of electric vehicles and generating more electricity from solar and wind facilities. Near-term, Joe Biden has said that, if elected, he will implement a ban on drilling on federal land and in offshore waters. Significantly, federal leases accounted for more than 20% of US oil and gas production in 2019, according to industry sources. Offshore production in the Gulf of Mexico is largely dependent on federal leases being issued.

Colorado, New Mexico and Wyoming particularly exposed to a drilling ban: Oil and gas production in the states of Colorado (Denver-Julesburg), New Mexico (Permian) and Wyoming (Powder River/Niobrara) is heavily focused on federal land. All three-host major shale oil and gas basins. Other measures that could be implemented quickly by an incoming Biden administration include tightening methane emissions, restricting gas flaring and raising federal royalty rates. Downstream refinery emission restrictions are also a possibility as we believe is a hike in federal taxes on gasoline and diesel. If necessary, several if not all these measures could be implemented by Presidential decree.

Biden/Harris have ruled out a ban on fracking but we can't be sure: As far as fracking is concerned, Joe Biden and his Vice-Presidential nominee, Kamala Harris have specifically ruled out a ban on the practice. The latter however has previously supported legislation proposed by Representative Alexandria Ocasio-Cortez to implement such a ban. Despite protestations to the contrary, we can't rule out a ban being implemented in due course. Given high rates of depletion and impermeable reservoirs this would, of course, have disastrous consequences for production and costs of operation. A belated realisation of the impact is probably why there has been some back tracking on a fracking ban in mainstream Democrat circles of late.

Some, such as Goldman Sachs, have suggested that a Biden presidency would be positive for the petroleum industry. The thinking is that a raft of restrictive measures would boost costs, constrain supply and thereby lift crude prices. While this might be the case in the short term, Joe Biden's energy plan would also depress demand and in the medium-term squeeze margins. Ultimately the viability of the industry would be in question. Those operating on federal property could face particular difficulties while downstream refining operations would potentially be heavily impacted by declining utilisation and a potential collapse in margins.

SUPPLY-DEMAND BALANCE

2020

Market status

Dramatic swing to surplus in H1 2020: After being in modest deficit in the fourth quarter of 2019 of about 0.18mm b/d, the petroleum market globally swung dramatically to substantial surplus in the first half of 2020. Based on EIA data, there were surpluses of 5.77mm b/d and 7.34mm b/d in the first and second quarters respectively. These surpluses were unprecedented and reflected the collapse in demand and lagged response of supply following the onset of the covid crisis.

Sharp swing back to deficit in Q3 and probably Q4: Reflecting measures to cut output in the second quarter in both the OPEC and non-OPEC worlds and a firming demand trend, the petroleum market tightened markedly in the third quarter with a swing to a sizeable supply deficit. According to the EIA, this was 3.1mm b/d. The market is expected to reflect a similarly sized deficit of 2.96mm b/d in the fourth quarter of 2020. Overall, the EIA's forecasts call for a supply surplus in 2020 of 1.74mm b/d. This would be the largest surplus since before the Asian Financial crisis of the late 1990s. The previous high was 1.70mm b/d in 1998.

Demand

Demand plunged in April but recovered strongly in May and June: Demand globally was off year-on-year by 5.5% in the first quarter and 15.9% in the second based on EIA data. At the low point in April demand was down about 30% but during May and June the trend firmed noticeably. During the second quarter demand was off 16% year-on-year with the OECD and non-OECD worlds down by 21% and 12% respectively. Helping constrain the decline in the non-OECD world was a relatively small drop of 9% in China, the world's second largest market for petroleum products.

Demand off YOY by 8% in Q3: Based on the EIA's provisional data the year-on-year shortfall narrowed significantly in the third quarter as the covid crisis eased with a decline of 8%. For the quarter, demand was off 11% and 5% in the OECD and non-OECD worlds respectively. Significantly, by the third quarter Chinese demand had broadly returned to year earlier levels. Demand in India also rose strongly between the second and third quarters as covid restrictions were relaxed but was still down 10% year-on-year. By the third quarter of 2020 the demand for surface transportation fuels and industrial applications for petroleum products, including middle distillates, fuel oil and NGLs had to a considerable extent returned to normal.

Aviation fuel is the key area of weakness with a decline of 25-30% likely in 2020: The key area of demand weakness post the covid crisis has been aviation fuel. According to the BP Statistical Review, over the ten years to 2019 aviation fuel demand grew by 2.6% pa to 7.98mm b/d (including military applications), well above the average for all petroleum products of 1.6% pa. Aviation's weighting in the petroleum mix in 2019 was 8%. Based on IEA data, aviation fuel demand in 2020 was already down year-on-year by about 15% in the first quarter and in the second quarter was off around 50%. Over the balance of 2020 the IEA is looking for year-on-year declines of about 30% and 10% in the third and fourth quarters respectively. The IEA's forecasts were made some months ago and given the ongoing malaise in air travel could well be optimistic particularly for the fourth quarter. In our view, a decline in aviation fuel demand of at least 25% to 6mm b/d is in the cards for 2020. A drop of 30% or more to perhaps 5.5mm b/d would not be surprising.

Demand overall in 2020 could be off 8.5% according to EIA: At this stage, greater than normal uncertainty surrounds the outlook for petroleum demand globally in the fourth quarter of 2020. The EIA is looking for demand of 97.05mm b/d, the highest quarterly level for 2020 and a modest, in the circumstances, 4.8% decline on a year earlier. All told, the

EIA is forecasting oil demand globally in 2020 to drop by 8.5% to 92.84mm b/d, the lowest annual average since 2014.

Production

Near record production globally in early 2020: Oil production globally in the first quarter of 2020 was running at near record levels driven by non-OPEC producers. This continued a trend that has been apparent for much of the past decade. Non-OPEC production for the period was 66.42mm b/d, up 1.49mm b/d or 2.3% on a year earlier.

The US remained the key driver but significant contributions to growth were also made by Canada, Brazil, Norway and the newcomer on the stage, Guyana. Canadian production was buoyed by higher oil sands bitumen and synthetic light crude output while Brazil was lifted strongly early in the quarter by new pre-salt projects coming on-stream in the Santos Basin. Norwegian output has been lifted in 2020 by about 0.35mm b/d reflecting the start-up in late 2019 of the giant Johan Sverdrup field. This is now the largest field in the North Sea. In Guyana the key development has been ExxonMobil's offshore Liza field coming on-stream in the closing days of 2019. Production in early 2020 was running at about 0.1mm b/d.

OPEC crude and NGL output in the first quarter of 2020 came in at 28.28 and 5.28mm b/d down 5.5% and 3.5% respectively. Overall world production during the period came in at 100.78 mm b/d according to EIA, up 0.4% on a year previously.

Sharp fall in Q2 in response to a collapse in prices: In the second quarter of 2020 production globally fell sharply both quarter on quarter and year-on-year in response to a collapse in oil prices. For the period production was 92.4mm b/d, down 8% on a year earlier. The decline reflected sharp drops in both OPEC and non-OPEC output. In terms of the former lower output was driven by the OPEC+programme aimed at taking an unprecedented 9.7mm b/d out of production schedules. Unusually, non-OPEC producers outside the OPEC+programme responded quickly to the dire market backdrop by shutting in wells and sharply cutting back development activity. These measures enabled depletion to flow through to production rates.

Non-OPEC output was driven lower by the US and Canada: Nowhere were the cutbacks more pronounced than in the US where production fell 2.6mm b/d between the first and second quarters of 2020. Canadian production also fell 0.7mm b/d on the same basis. Quite simply prices in many cases during the second quarter of 2020 dropped to levels below the cash costs of operation. Significantly short cycle development projects in the US tight reservoir basins were rendered uneconomic at prevailing prices.

Subdued trend in Q3 followed by a firmer trend in Q4: Based on EIA data, production globally probably dipped slightly between the second and third quarters to about 91mm, off 9% from a year previously. A firmer trend, however, is expected in the fourth quarter reflecting strengthening demand, a partial recovery in prices, a relaxation of the OPEC+agreement, the underlying upward trend in Brazil, Guyana and Norway and the restoration of production in Libya. The EIA is looking for production globally in the fourth quarter of 94.1mm b/d, still down 7.5% on a year ago. On average the EIA's forecasts call for production in 2020 of 94.6mm b/d, 6.1% below 2019.

2021

EIA forecasting moderate deficit of 0.27mm b/d: In its October Short-Term Energy Outlook, the EIA is looking for a significant petroleum market tightening in 2021. A swing to a supply deficit of 0.27mm is forecast predicated on a strong rebound in demand and lagging supply. Specifically, the forecast reflects the following year-on-year movements:

- Global demand growth 6.25mm b/d, 6.7%

- Non-OPEC output growth 1.28mm b/d, 2.0%
- OPEC crude oil output growth 2.95mm b/d, 11.4%
- OPEC NGL output unchanged

Overall, buoyant supply growth is likely to constrain the emergence of a deficit in 2021 despite the potential for strong demand growth.

Strong rebound in demand: The above would imply global petroleum consumption of 99.1mm b/d or within striking distance of the 2019 record of 101.5mm b/d. Non-OPEC oil production of 65.1mm b/d would also be close to the 2019 record of 66.0mm b/d but OPEC crude output of 28.8mm b/d would still be significantly lagging the high in recent years of 31.7mm b/d. The gain in consumption in 2021 is expected by the EIA to be broadly distributed between OECD and non-OECD markets.

Subdued US production trend but pockets of growth elsewhere: For the first time in many years non-OPEC production in 2021 is unlikely to be driven by the USA. Here, production is expected by the EIA to trend broadly flat at an admittedly historically high level with development subject to financial constraints. According to the EIA, non-OPEC production in 2021 will be driven by recovering trends at major producers notably Canada and Russia and secular upward trends in such countries as Brazil, Norway and Guyana where new projects are coming on-stream.

Key production driver in 2021: OPEC looks like being the key driver behind production in 2021. We also see it as being a wild card. With major spending commitments we know that most OPEC producers would dearly like to boost production at the earliest opportunity. The current OPEC+production cutbacks are scheduled to be reduced by 2mm b/d in January 2021 but it is not inconceivable that OPEC members could seek a more robust recovery.

There is also the issue of the three OPEC members, Iran, Libya and Venezuela which are outside the current quota regime. A Democrat victory in the US could result in an easing of sanctions on Iran, although possibly not Venezuela. Libyan production has been trending rapidly higher since a peace agreement was reached between the central government and the renegade eastern commander, General Haftar, in September. After running at nominal rates since early in 2020 production has apparently recently reached 0.5mm b/d and could conceivably exceed 1mm b/d in early 2021.

EIA's economic growth assumption for 2021 is contingent on a covid vaccine being widely available: The EIA's key economic assumption for 2021 is GDP growth of 5.3% globally. This equals the growth rate in 2010 following the financial crisis of the late 2000s. While we believe a GDP growth rate of 5%+ is plausible given the virtually unprecedented plunge of 2020, we suspect it will require a significant easing of the covid crisis in the coming months. This will presumably necessitate the widespread availability of an efficacious (at least 50%-60% effective) vaccine by perhaps the first quarter of 2021. Clearly, slower economic growth than postulated by the EIA would be reflected in lower petroleum demand and the potential for a supply surplus.

2022

Continuing tightening of the market: We believe there is a strong case for suggesting a continuing tightening of the petroleum market globally in 2022 driven by a recovering economy. This, of course, is contingent on the rolling back of the covid crisis and a successful inoculation programme globally. Our scenario for 2022 calls for a supply deficit of 0.61mm b/d and reflects the following:

- Global demand growth 3.5%
- Non-OPEC oil production 2.5%

- OPEC crude production 4.3%
- OPEC NGLs 5.0%
- Global oil production 3.2%

The scenario for 2022 would imply records for both global petroleum consumption and non-OPEC output of 102.6mm b/d and 66.7mm b/d respectively.

Our global GDP growth (oil weighted) forecast for the above is 3.7%. This is on the high side compared with recent years, but we believe is plausible given that the economy should still be in a pronounced recovery phase in 2022 following the plunge of 2020. The forecast would imply a world economy in 2022 3.4% larger than in 2019.

EXHIBIT 13: GLOBAL OIL SUPPLY/DEMAND BALANCE

Mm b/d	2016	2017	2018	2019	2020e	2021e	2022e
Global consumption	96.74	98.83	100.62	101.46	92.84	99.09	102.56
Non-OPEC oil production	60.69	61.35	64.06	66.04	63.81	65.09	66.72
OPEC NGL production	**5.25**	**5.30**	**5.31**	**5.38**	**4.97**	**4.98**	**5.23**
OPEC crude call	30.80	32.18	31.25	30.04	24.06	29.02	30.61
OPEC crude production	31.66	31.54	31.44	29.27	25.80	28.75	30.00
Surplus/(deficit)	**0.86**	**-0.64**	**0.19**	**-0.77**	**1.74**	**-0.27**	**-0.61**
Global production	97.60	98.19	100.81	100.69	94.58	98.82	101.95
Non-OPEC share of global production %	62.2	62.5	63.5	65.6	67.5	65.9	65.4
YOY changes %							
Global consumption	1.2	2.2	1.8	0.8	-8.5	6.7	3.5
Non-OPEC crude production	-0.9	1.1	4.4	3.1	-3.4	2.0	2.5
OPEC crude production	3.2	-0.4	-0.3	-6.9	-11.9	11.4	4.3
Global oil production	0.5	0.6	2.7	-0.1	-6.1	4.5	3.2
YOY changes mmb/d							
Global consumption	1.10	2.09	1.79	0.84	-8.62	6.25	3.47
Non-OPEC crude production	-0.58	0.66	2.71	1.98	-2.23	1.28	1.63
OPEC crude production	0.98	-0.12	-0.10	-2.17	-3.47	2.95	1.25
OPEC NGL production	0.06	0.05	0.01	0.07	-0.41	0.01	0.25
Global oil production	0.46	0.59	2.62	-0.12	-6.11	4.24	3.13
World GDP growth (oil weighted) %	2.8	3.2	2.9	1.9	-5.3	5.3	3.7
US GDP growth (2012 dollars) %	1.7	2.3	3.0	2.2	-4.1	3.5	2.6

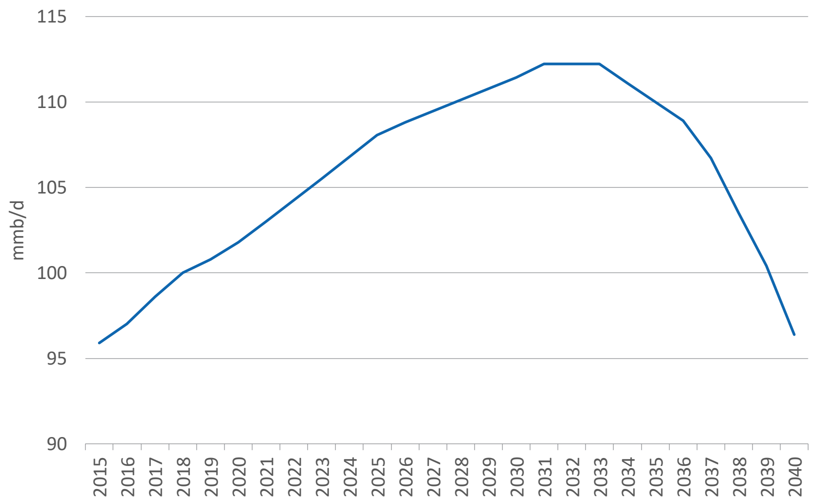
Source: EIA and Allenby Capital. Note: The demand forecasts were made pre-China coronavirus epidemic.

LONG TERM PETROLEUM DEMAND

Implausibly, BP believes we may already have peaked: Over the past year or so and particularly over recent months there has been considerable discussion in industry circles concerning the long-term outlook for petroleum. Speculation on the timing of peak oil demand has been rife. Amazingly perhaps we have had one of the world's petroleum titans BP, conjecture that peak demand might already have occurred. Since announcing its radically new strategy earlier in 2020 BP is like a reformed sinner that has discovered God. It now wants to be holier than thou and put forward bearish petroleum volume scenarios to justify its strategic decisions such as cutting oil and gas output by 40% by 2030.

We regard a forecast of peak demand at the 2019 level of circa 101.5mm as implausible other than perhaps in the event of a prolonged covid crisis without a viable vaccine or therapeutic remedies. Assuming that a viable vaccine is widely deployed near term there is no reason to believe that there will not be a strong rebound in economic activity and petroleum demand. The rebound is likely to take us comfortably past the 2019 in short order.

Exhibit 14: GLOBAL OIL DEMAND SCENARIO



Source: EIA & Allenby Capital

We continue to look for peak demand in the early 2030s at about 112mm b/d: In our December 2019 Oil & Gas Macro Outlook we expressed our thoughts on the long- term outlook for petroleum consumption globally. We see no reason to radically change the views expressed last December. Our demand scenario was as follows:

- Growth of 1.2% pa between 2020 and the mid-2020s which is roughly in line with the pace in recent years up to 2019. This assumed global economic growth of around 3.0%pa. Petroleum demand of about 108mm b/d was expected in 2025 on this scenario against 101.8mm b/d in 2019. During this period, we expected vehicle electrification to have relatively little impact on petroleum demand given the still low penetration of such vehicles and the significant lag in introducing the new technology.

- A significant slowdown in consumption growth to about 0.6% pa in the second half of the 2020s and into the early 2030s assuming that underlying economic growth remains at about 3% pa. The slowdown is driven mainly by a sizeable build-up in the availability of light vehicles and public policy initiatives to curb the use of fossil fuels. On our scenario demand peaks out in the early 2030s at about 112mm b/d.

- Post the early 2030s we believe petroleum consumption will drift down possibly hitting around 105mm b/d by 2035. By 2040 we think demand could be back down to about 95mm b/d driven by technological advances particularly in vehicle electrification and continuing public policy initiatives to restrict the use of fossil fuels. The last mentioned would include outright ban on the sale of ICE powered light vehicles.

We believe the above remains a valid scenario for petroleum consumption over the next 20 years or so for the following reasons:

- Petroleum and natural gas liquids continue to account for a third of the primary energy mix. This is comfortably the largest weighting. Interestingly hydrocarbons overall including natural gas and coal account for 84% of primary energy usage. Short of dramatic technological breakthroughs, it is going to be very difficult if not impossible in the near term to radically change the weighting in the mix of either petroleum or indeed hydrocarbons.

- The petroleum industry remains dominant in its key markets of highway transportation (light vehicles, medium and heavy trucks and buses), off-highway machinery (agricultural equipment, earth moving machinery and construction equipment), off-grid power generation (generator sets), aviation, marine and petrochemicals. The reason that petroleum is dominant across the transportation applications relates to its superior properties particularly in terms of very high energy density and ease of transportation. There are no easy technological solutions to quickly replacing petroleum-based products across these applications.

- Electrification technologies in transportation applications whether using lithium-ion batteries or hydrogen fuel cells all have major drawbacks. In the case of the former there remain issues in terms of range, re-charging times, battery life, raw material availability, battery cell manufacturing bottlenecks and cost. A further challenge concerns the cost and time required to establish a recharging network and boosting power generation and distribution capacity. The drawbacks on recharging and range still heavily compromise the use of battery electric vehicles (BEVs)for medium to long distance use and particularly in trucking applications. For these to be overcome will probably require a major breakthrough in developing solid-state battery technology produced at high volume. This would appear unlikely this side of 2025 and quite possibly 2030.

  Hydrogen fuel cells in conjunction with electric motors constitute a more viable propulsion system technically than BEVs both for heavy trucks and the heavier end of light vehicles such as pickup trucks and SUVs. They are energy efficient vis-à-vis ICEs, emission free and have similar range and refuelling characteristics to gasoline or diesel-powered vehicles.

  Inevitably perhaps, there are also major drawbacks to hydrogen fuel cells. These primarily relate to cost, the need to use expensive platinum catalysts, weight, the energy intensive process required to produce hydrogen and the need to transport and store hydrogen under pressure in liquid form. Fuel cells are also only emission free if hydrogen is produced via the electrolysis of water using electricity generated from renewables. Note, however, that even if hydrogen is produced from natural gas, as is usually the case, emissions are likely to be significantly lower than with gasoline or diesel ICEs due to the greater energy efficiency of fuel cell/electric motor propulsion. A key issue for fuel cell acceptance will be the distribution network for hydrogen. Presently this is sparse. We suspect it will be a slow process for fuel cell propulsion to gain acceptance in car and truck applications.

- There is a park around the world of roughly 1.4bn light vehicles. Even if sales of new ICE powered vehicles are banned in a number of areas such as Europe post 2030 there will still be a sizeable park of vehicles requiring diesel and gasoline probably significantly past 2050. The average life span of a vehicle in Europe and North America is around 20 years.

- Aviation's propulsion system of choice is likely to remain the turbo-fan engine using aviation fuel for the foreseeable future. Only this can offer the performance, range and compact fuel storage characteristics required for even short and medium distance flying with large passenger or freight aircraft. The key factor is the high energy intensity of aviation fuel which no alternative energy source is anywhere near replicating. Battery or fuel cell powered propulsion systems for even relatively small jets such as a Boeing 737 or Airbus A320 would need to be so large as to be impractical.

- Petrochemicals are likely to remain a key source of growth for the foreseeable future. Currently, petrochemicals account for about 12% of oil use and have been the fastest area of growth for the petroleum industry for a number of years. Broadly growth trends at about the same pace as world GDP. Petrochemicals such as polymers have an excellent range of properties which makes their use near ubiquitous in manufactured products. Usually they cannot be substituted cost effectively and the applications are essential for modern living.

WHAT ABOUT THE COVID CRISIS?

Arguments suggesting that petroleum demand has been permanently adversely impacted by the covid crisis are probably overstated: There are some, like BP, that argue petroleum demand has been permanently adversely impacted by the covid crisis. Two arguments are proffered. Firstly, it is argued that aviation usage has been lowered due to the rapid take-up of cost-effective video teleconferencing via such services as Zoom and Microsoft Teams. Secondly, the working from home phenomenon also facilitated in part by Zoom and Microsoft has permanently reduced commuting and therefore fuel usage.

Travel has not lost its allure and a backlog of face-to-face meetings requiring travel has arguably built-up: Regarding the first point we think it worth mentioning that video conferencing is not new. It has been possible probably for at least 25 years. What is new is the availability of cost-effective video conferencing. We believe that post the crisis there may well be a surge in demand for aviation from both tourist and non-tourist sources. Travel has not lost its allure while there is likely to be a backlog of business-face to face meetings requiring travel post the crisis.

Less commuting may be offset by greater use of vehicles for recreational purposes: Reduced commuting is a possibility post the crisis, although it remains to be seen how feasible it is to operate large businesses over long periods on a very decentralised and dispersed basis. From a petroleum perspective there is a question as to how much would public transport as opposed to personal transportation be impacted. It could be that the former may be more impacted than the latter in some parts of the world such as London and New York. The commute may also be partially offset by greater use of vehicles for recreational purposes such as going to the golf course.

Home deliveries require greater use of vans and trucks: The new-found craze for home deliveries also does not necessarily translate into fewer highway miles and lower fuel consumption. All these deliveries, in the main, have to be made by diesel powered van and truck. It is not for no reason that one of the most buoyant sectors of the automotive business of late has been small and medium vans.

In summary, structural influences may be at work trimming petroleum demand at the margin. We believe, however, for a period of possibly two or three years post the crisis ending, countervailing influences would drown out this factor. To achieve this state of affairs will require an efficacious covid vaccine. A prolonged covid crisis over several years would clearly have a severe depressing effect on petroleum demand.

WHAT ABOUT THE POLITICOS?

Carbon taxes and tighter regulation are very real possibilities across the OECD world: There is a possibility that political action will be taken to tighten regulation on carbon emissions and boost taxes on fossil fuel use in support of climate policy. Across the OECD world a carbon tax is a very real possibility over the next few years. Indeed, even oil companies are suggesting this would be the most effective way of dealing with emissions.

A key issue for the politicos in the coming years will be the policy stance vis-à-vis the very large park of ICE powered vehicles when new sales are prohibited. Will they simply allow the park to be organically run down or will they attempt to accelerate the pace through enforced scrappage? Policy tightening would clearly lower the demand peak as well as bringing it forward. A radical tightening of climate policy will however have profoundly negative economic consequences. It could also provoke an extreme political response or worse. Such considerations may constrain extreme policy initiatives.

CRUDE OIL PRICE OUTLOOK

MARKET THESIS AND FORECASTS

2020

Flat to down trend in Q4: During the fourth quarter of 2020 we look for benchmark light crude prices to trend flat to down compared with the prior quarter in the absence of any major supply outages. Keeping a lid on prices we believe will be two factors as follows:

- A lacklustre demand outlook reflecting sluggish economic activity particularly in the OECD world. The underlying issue here is the depressing influence of covid-19 on business and consumer confidence and the associated tightening of policy measures to control transmission of the disease.
- A still sizeable inventory overhang combined with a firming output trend.

Countervailing influences helping support prices we think will be a market remaining in deficit and speculation regarding the availability of a covid vaccine and improved therapeutic treatments early in 2021. Positive news on the vaccine and therapeutics fronts could, in fact, conceivably buoy prices in the coming months. Further support for prices in the closing months of 2020 could relate to OPEC+ indicating a willingness to delay a planned 2mm b/d boost to production in early January 2021

Brent $42.0/barrel and WTI $40.2/barrel Q4: Given the above, we would look for Brent to average $42.0/barrel in the fourth quarter of 2020. This would take the average for the year to $41.3/barrel, 36% under 2019 and a post 2003 nominal low. As noted earlier, the Brent-WTI spread narrowed markedly between 2019 and 2020 apparently reflecting more pronounced cutbacks in the US than the Atlantic Basin and upgraded US export infrastructure. These factors are likely to remain apparent in the coming months and could be given added impetus by a resumption of Libyan production which will raise the availability of light crude in the Atlantic Basin. In late October the WTI discount to Brent was running at about $1.8/barrel against $2.09/barrel in the third quarter. Using the former would imply a 2020 fourth quarter price of $40.2/barrel. Our forecast average for 2020 is $38.6/barrel, down 32% on 2019 and a post 2003 low.

Our latest Brent and WTI forecasts constitute substantial downgrades compared with those given in February 2020 at the onset of the covid crisis of $56.2/barrel and $51.8/barrel respectively. When making the forecast in February we had assumed that then covid epidemic in the Chinese province of Hubei (Wuhan is the capital) would not evolve as a global pandemic within a matter of months.

2021

Consensus could be too cautious if we have visibility on a medical solution to covid by late 2020: The consensus view is for a moderate increase in benchmark light crude prices in 2021 into the $45-50/barrel range. A continuing draw on inventories and a significant recovery in demand propelled by strengthening economic activity globally are expected to support the upward trend. Expectations generally, however, are being dampened by uncertainty surrounding the strength of the economic backdrop in 2021 and therefore the demand outlook given the persistence of the covid crisis. While the consensus view is plausible enough, we would argue that the oil price outlook post the end of the fourth quarter could be looking more auspicious than the current consensus. We think it likely that by late 2020 we will have visibility on a medical solution via a vaccine to the covid crisis. It is also likely in our view that OPEC+ will defer a relaxation of the production cutback regime scheduled for early January.

Upward quarterly trend: Subject to the two above considerations we would look for Brent ($/barrel) to trend as follows through 2021: Q1$46.0, Q2 $52.0, Q3 $58.5, Q4 $58.5. The average for the year would come in at $53.8/barrel. The flattening trend in the fourth quarter reflects the assumption that production will gather pace post the first quarter reflecting comfortably profitable prices for most producers and the desire of several OPEC members, such as Iraq and Libya, to boost output more or less regardless.

Brent-WTI spread to remain narrow: We expect the Brent-WTI spread in 2021 to remain narrow by the standards of recent years. This reflects both the upgrading of the pipeline infrastructure from the Permian and Midcontinent to the Gulf Coast and our expectation of a subdued trend in US production in the Lower 48. We would look for a spread of $2.5/barrel which is roughly equivalent to the spot tariff for shipments from Cushing to the Gulf Coast. This would imply WTI averaging $51.3/barrel. Significantly, this would suggest a moderately profitable price for those basins able to attract prices broadly in line with WTI pricing.

Our current Brent and WTI forecasts for 2021 compare with $63.3/barrel and $58.6/barrel respectively made in February 2020. The downgrade reflects a completely different macro- economic and petroleum market backdrop approaching 2021 to the one forecast. Global economic activity in early 2021 is significantly lower than implied by the February 2020 forecast.

2022

Further moderate price gains: Reflecting our expectation of a widening supply deficit and hopefully a return to at the semblance of normality in the world economy, we see scope for a further firming in benchmark light product prices in 2022. We forecast Brent and WTI averaging $61.0/barrel and $58.5/barrel respectively. In the event of a much stronger upward trend we would expect a rapid supply response particularly from OPEC producers and possibly the US shale patch. OPEC producers, including Iran, Libya and Venezuela, have both the surplus capacity and financial pressure to boost production.

Issue of sanctions on Iran and Venezuela in the event of a Biden Presidency: A key issue here is going to be the stance of a Biden Presidency, should it materialise, towards sanctions on Iran and Venezuela. A relaxation of sanctions, depending on the state of the economy, could even exert some downward pressure on prices at least for a while. US shale operators can in theory bring on new capacity with short lead times compared with conventional plays given the availability of low-risk drilling opportunities and an inventory of drilled but uncompleted wells (DUCs). Their ardour may however be constrained by financing to a greater extent than in the past.

WILD CARDS AND COMMODITY PRICE RISK

Over the next two or three years we several major wild cards surrounding the petroleum industry. The key one surrounds the duration of the covid crisis and the related issue of the timing of a widely available vaccine. There are very serious implications for the world economy and petroleum demand if a vaccine is not available by the early months of 2021. Only with an effective vaccine will the world have the opportunity to develop herd immunity without millions of deaths and massive collateral economic damage. Developments over recent months have shown that it is very difficult simply to learn to live with the virus.

Outside the covid crisis we see the key wild cards as follows:

- The cohesion of the OPEC+accord particularly in the event of a need to maintain a tight cutback regime to support prices.
- The pace at which Libyan production is brought back on-stream.
- The status of US sanctions on Iran and maybe Venezuela assuming a Biden Presidency. Joe Biden has suggested he is in favour of re-joining the P5+1 Iran nuclear accord which includes the five permanent members of the UN Security Council (US, Russia, China, UK and France) plus Germany. Presumably such a move would imply relaxing or lifting US sanctions on Iran. This could potentially unleash

around 2mm b/d of oil production onto the market in the absence of cutbacks elsewhere.

- The status of the Maduro regime in Venezuela. Does President Maduro continue to persevere with the support of Russia producing about 0.5mm b/d of oil or does the regime fall over the next year or two. If it does this would usher in a period of significantly higher production. Note, unless there is a rapprochement with the US Venezuela is likely to be confronted in the coming years with the issue of stranded assets. The country has the largest petroleum reserves in the world and is therefore potentially imperilled by decarbonisation measures.
- The stance of US producers in the Lower 48 states to rising prices. Do they pursue higher production or prioritise cash flow and debt reduction?
- Climate change issues and the associated political response. Will carbon taxation be widely adopted?
- The details of US energy and environmental policy assuming a Biden Presidency. A key question is, where does Joe Biden really stand on fracking. He has the power potentially to roll back the US oil and gas production revolution of the past 20 years.

EXHIBIT 15: BRENT 2009-2022 QUARTERLY PRICES ($/BBL)

	Q1	Q2	Q3	Q4	Average
2009	45.1	59.4	68.4	75.0	62.0
2010	76.8	78.6	76.4	86.9	79.7
2011	104.9	116.8	109.1	109.3	110.0
2012	118.7	108.7	109.8	110.9	112.0
2013	112.8	102.9	110.0	109.4	108.8
2014	107.9	109.8	102.2	76.4	99.1
2015	53.9	61.7	50.2	43.7	52.4
2016	33.9	45.6	45.8	49.3	43.7
2017	53.7	49.7	52.1	61.5	54.3
2018	66.8	74.8	75.0	68.3	71.2
2019	63.1	69.1	61.9	63.4	64.4
2020e	50.0	29.5	43.0	42.0	41.1
2021e	46.0	52.0	58.5	58.5	53.8
2022e	59.0	61.0	62.0	62.0	61.0

Source: EIA and Allenby Capital

EXHIBIT 16: WTI 2009-2022 QUARTERLY PRICES ($/BBL)

	Q1	Q2	Q3	Q4	Average
2009	43.2	59.7	68.1	76.0	61.8
2010	78.8	77.9	76.1	85.2	79.5
2011	93.9	102.3	89.5	94.0	94.9
2012	103.0	93.3	92.2	88.2	94.2
2013	94.3	94.1	105.8	97.6	98.0
2014	98.7	103.1	97.6	73.2	93.2
2015	48.5	57.9	46.4	41.9	48.7
2016	33.2	45.4	44.9	49.1	43.2
2017	51.8	48.2	48.2	55.4	50.9
2018	62.9	68.1	69.7	59.6	65.1
2019	54.8	59.9	56.4	56.8	57.0
2020e	45.3	28.0	40.9	40.2	38.6
2021e	43.5	49.5	56.0	56.0	51.3
2022e	56.5	58.5	59.5	59.5	58.5

Source: EIA and Allenby Capital

EXHIBIT 17: BRENT AND WTI LONG-TERM PRICE TRENDS

$/bbl	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020e	2021e	2022e
Brent	62.0	79.7	110	112	108.8	99.1	52.4	43.7	54.3	71.2	64.4	41.1	53.8	61.0
WTI	61.8	79.5	94.9	94.2	98	93.2	48.7	43.2	50.9	65.1	57.0	38.6	51.3	58.5

Source: EIA & Allenby Capital

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