NATURAL RESOURCES

February 2020

OIL & GAS

OIL & GAS MACRO OUTLOOK

Coronavirus epidemic demand shock

The coronavirus epidemic in China has delivered a demand shock to the oil market with a current impact exceeding 2mm b/d. Based, however, on the experience of the SARS crisis in 2002/3 the impact of the coronavirus outbreak should ease during the first half of 2020 and dissipate by Q3. Our estimate of the potential global 2020 impact is 0.7mm b/d. While this would widen our forecast of the supply surplus to about a 1mm b/d we think it likely that it would be offset in whole or in part by the OPEC+consortium cutting output. Assuming a stabilisation in the coronavirus epidemic in the coming months, we look for a firming trend in prices post the first quarter of 2020. Based on our expectations of a tightening market related in large part to slowing US production growth we would expect the firming trend to persist in 2021. Unusually, the outcome of the US Presidential election will potentially have implications for oil markets. The policy positions of the leading Democrats would reverse the shale oil and gas revolution of the past ten years.

- **Supply/demand balance**: According to the EIA, the oil market was balanced in 2019. In its January report, the EIA looked for a modest surplus (pre coronavirus) of 0.26mm b/d, in line with earlier indications. Based on our assessment of the impact of the coronavirus epidemic we believe the 2020 supply surplus could be about 1mm b/d. A new OPEC+production accord currently under discussion could partially offset the surplus.

- **Oil production:** Non-OPEC production growth in 2020 is likely to be strong at 2.6mm b/d, according to the EIA. The major contributors will be the US, Brazil, Norway, Canada and Guyana. Brazil should be driven by major development activity in the pre-salt Santos Basin. Norway will receive a considerable boost from the start-up of the giant Johan Sverdrup field while offshore Guyana will be making a first-time contribution in 2020. Driven by the US the EIA is forecasting much slower non-OPEC output growth in 2021 with a gain of 0.9mm b/d. Based on EIA data, OPEC production before allowing for a new OPEC+accord is likely to dip by about 0.6mm b/d in 2020 and to be broadly flat in 2021.

- **Oil demand**: Oil demand growth globally was relatively weak in 2019 at 0.8mm b/d. Before the onset of the coronavirus epidemic the EIA was looking for demand growth to strengthen in 2020 to 1.34mm b/d. Strengthening demand reflected a combination of higher GDP growth, the coming on-stream of major petrochemical plants in the US, China and Russia and the volume impact of the new IMO rules for marine fuel sulphur. Based on our estimate of the potential impact of the coronavirus epidemic, demand growth in 2020 would be 0.64mm b/d, the smallest gain in at least ten years The EIA is forecasting demand growth in 2021 of 1.38mm b/d.

- **Forward curves**: The backwardation at the front-end of the forward curves for Brent and WTI that has been apparent since July 2019 has unwound in recent days. Both curves are now broadly flat for all forward dates through late 2022 reflecting plentiful near-term supplies. This is consistent with falling demand in China. The middle and back-end of the curves are in mild contango possibly suggesting longer term market expectations of a tightening market. The back-end of the Brent and WTI curves terminate in Q1 2029 at $58.2/barrel and $52.2/barrel respectively. This compares with $54.5 and $50.2 for spot Brent and WTI in early February 2020.

- **Price forecasts**: Our Brent and WTI forecasts for 2020 have been downgraded. Brent is now forecast to average $56.2/barrel against $61.5/barrel previously while WTI decreases from $56.3/barrel to $51.8/barrel. The downgrades reflect the impact of the coronavirus epidemic. For 2021 we look for Brent and WTI to average $63.3/barrel and $58.6/barrel respectively. Our forecasts for 2020 are $10/barrel lower than we were contemplating immediately before the onset of the coronavirus epidemic. We believe the price forecast risks are to the downside.

BRENT VS WTI

	1m	3m	12m
Brent $/bbl	-15.0%	-4.1%	-2.0%

Source: EIA

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

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EXECUTIVE SUMMARY

Recent price developments: Benchmark light crude prices ended 2019 strongly. This reflected a broader trend in commodity prices and was driven in part by an easing of recessionary fears, in part by a truce in the US-China trade war and in part by growing tension in the Middle East between the US and Iran. The highs in December for Brent and WTI were $69.7/barrel and $61.8/barrel respectively which were both well above the yearly averages of $64.4/barrel for Brent and $57.0/barrel for WTI. There was, therefore, significant carryover going into 2020.

Prices were given a further boost in the early days of January 2020 as a result of the US assassination of the powerful Iranian Red Guard General, Qassem Soleimani. Brent and WTI peaked at approximate seven-month highs of $70.3/barrel and $63.3/barrel respectively on January 6/7. The surge in prices, however, proved short-lived much as had been the case in September 2019 after the Iranian attack on key Saudi Aramco processing facilities. Prices initially softened due to a well-supplied market and no descent into serious military conflict. Adding to the bearishness especially in the US was falling product prices particularly for gasoline.

In the second half of January downward price pressure intensified. Again, this was part of a broader phenomenon in commodities related to the potential vulnerability of demand to the coronavirus epidemic in China. Brent and WTI plumbed approximate 12-month lows in early February of $54.2/barrel and $49.9/barrel respectively. Prices were down about 21% on the early January highs.

Brent-WTI spread: The Brent-WTI spread widened between the third and fourth quarters of 2019. The fourth quarter spread came in at $6.6/barrel, against $5.5/barrel in the third quarter and $8.8/barrel in the first half of 2019. The widening between the third and fourth quarters derived principally from geopolitical tension in the Middle East and the OPEC+production accord agreed in early December 2019. During January 2020 the Brent-WTI spread trended at about $6/barrel but in early February narrowed sharply to about $4.2/barrel. The narrowing of late, we believe, reflects declining pipeline tariffs between Cushing (the settlement point for NYMEX crude) and Houston, new pipeline capacity from the Permian Basin to the Gulf Coast and the relative insulation of WTI from the collapse in Chinese demand. Pipeline tariffs between Cushing and the Gulf Coast are around $2.25/barrel. There is therefore a profitable arbitrage to be made by shipping oil to the Gulf Coast where light crude sells for prices close to Brent.

Forward curves: Structurally the forward market for Brent and WTI changed fundamentally in early February. Rather than the backwardation (near month prices higher than for the more distant dates) that characterised the forward market for more than six months, the front-end of the curves are now essentially flat for all dates through late 2022. This is consistent with the sharp and unexpected drop in Chinese demand of late and an apparent sizeable inventory build-up. The middle and backend of the curves reflect a mild contango (near month prices lower than for the more distant dates) pointing to expectations of a tightening market. The backend of the Brent and WTI curves terminate in Q1 2029 at $58.2/barrel and $52.2/barrel respectively. This compares with spot prices in early February 2020 of $54.5/barrel and $50.2/barrel for Brent and WTI respectively. Overall, the forward curves reflect a modest contango.

Supply-demand balance: The global oil supply-demand balance tightened considerably between 2018 and 2019 with a swing from a surplus of 0.92mm b/d to a marginal deficit of 0.02mm b/d, according to EIA data. A sizeable drop in OPEC production more than offset buoyant non-OPEC output and relatively slow demand growth.

Before the coronavirus outbreak in China in January 2020 the EIA was looking for a modest surplus of 0.26mm b/d which is in line with earlier forecasts. The principal driver behind the swing to surplus was a forecast hefty gain in non-OPEC output growth of 2.6mm b/d. This was expected to be driven by the US (shale basin development), Canada (oil sands cutbacks reversed), Brazil (pre-salt Santos Basin), Norway (Johan Sverdrup start-up) and Guyana (ExxonMobil's new Lizard field). The EIA was forecasting buoyant demand growth in 2020 of 1.38mm b/d but this will now need sharply reducing to allow for plunging Chinese demand. Reflecting our estimate of the potential impact on demand of the coronavirus epidemic of 0.7mm b/d we would now look for a supply surplus of about 1mm b/d. A new OPEC+ accord now under discussion could partially offset the surplus.

For 2021 the EIA calls for a tightening market with a deficit of 0.15mm b/d. Driving the swing is expected to be a marked slowdown in non-OPEC output growth and a still buoyant trend in demand. OPEC output is expected to remain policy constrained. Slower non-OPEC output growth is driven in large part by the US and stems from the lagged impact of lower development activity in the tight reservoir basins of Texas and the Great Plains.

Coronavirus impact: The coronavirus epidemic in China is the overwhelming preoccupation of commodity markets, including petroleum. Market concerns relate to the depressing impact on GDP and hence oil consumption of official measures to restrict movement and close business and industrial premises. Anecdotal evidence suggests that the impact of the epidemic on oil consumption has been heavy. A recent Bloomberg reported pointed to oil usage in China in early February being down year-on-year by 3mm b/d or over 20%. Our own analysis indicates a drop since the onset of the epidemic of 2.1mm b/d or 15%. Assuming the epidemic is similar in duration to SARS in 2002/3, we forecast declines easing in the second and third quarters of 2020. We believe a recovery is possible in the fourth quarter reflecting a rebound in industrial and business activity. Based on this scenario, we forecast Chinese demand to drop by 0.7mm b/d in 2020.

Market thesis: Assuming the coronavirus epidemic shows clear signs of stabilisation by the second quarter of 2020 plus OPEC+ production cutbacks we would expect to see oil prices firm over the balance of 2020. Stabilisation would provide visibility of an improving trend in infections and possibly the dissipation of the coronavirus outbreak during the second half. Our quarterly forecasts for Brent call for the following: Q1 $56.6, Q2 $54.0, Q3 $56.0, Q4 $58.0. The average for 2020 of $56.2/barrel is down 13% on 2019. Our 2020 WTI forecast of $51.8/barrel reflects a $4.4/barrel discount to Brent.

In the event of the above scenario we would expect the firming price trend to continue in 2021. The key factors here are a potentially tightening market reflecting slower non-OPEC output growth than for several years and what could be a strong recovery in demand in China. Note that prior to the onset of the coronavirus the EIA was already anticipating a buoyant demand in 2021 with growth of 1.34mm b/d. We see Brent trending upwards from $59.0/barrel in the first quarter to $66.0/barrel in the fourth quarter and averaging $63.3/barrel for the full-year. The forecast WTI discount of $4.7/barrel is similar to 2020.

Price forecasts: Our Brent and WTI forecasts for 2020 have been downgraded. Brent is now forecast to average $56.2/barrel against $61.5/barrel previously while WTI decreases from $56.3/barrel to $51.8/barrel. The downgrades reflect the impact of the coronavirus epidemic. For 2021 we look for Brent and WTI to average $63.3/barrel and $58.6/barrel respectively.

EXHIBIT 1: ENERGY PRICE SUMMARY

	Brent $/bbl	WTI $/bbl	Henry Hub $/mcf
2018	71.2	65.1	3.27
2019	64.4	57.0	2.66
2020e	56.2	51.8	2.38
2021e	63.3	58.6	2.63

Source: EIA, Allenby Capital

OIL & GAS MARKET DYNAMICS

OIL & GAS MARKET 2019 RETROSPECTIVE

Brent and WTI prices second highest in past five years: The oil market bulls may have found 2019 disappointing but in reality, it was a pretty good year for producers of light crude benchmark grades from a recent historical perspective. Average prices of $64.4/barrel for Brent, the international benchmark and $57.0/barrel for WTI the US Mid-continent benchmark, were the second highest in the past five years. Significantly, they implied comfortably profitable levels for the bulk of crude oil producers. Furthermore, prices were on an upward trend in late December 2019 and finished the month comfortably above the yearly averages. Brent finished 2019 at $67.8 /barrel while WTI was at $61.1/barrel for year on year gains of 34% and 35% respectively.

US refining crack spreads at comfortably profitable levels: In the US, at least, refining margins although below the stellar levels of earlier in the decade, when they exceeded $20/barrel, were also at comfortable levels from a profitability perspective. The USGC WTI 3-2-1 crack spread (gross refinery margin on converting three barrels of WTI into two barrels of gasoline and one barrel of diesel based on Gulf Coast product prices), for example, in 2019 averaged around $17/barrel against $15.9/barrel in 2018. By late January, however, the USGC 3-2-1 crack spread had slipped to about $11/barrel reflecting weakening trends in gasoline and diesel wholesale prices not fully matched by WTI.

Natural gas and LNG the major area of price weakness: The key area of weakness in hydrocarbons markets in 2019 was pipeline natural gas and international LNG (liquified natural gas). Pipeline gas prices were especially weak in the US. In late 2019 the US Henry Hub, Louisiana benchmark was hovering close to a multi-year low of $2.20/mm Btu ($13.2/boe) while at the Waha Hub in the Permian Basin natural gas was selling for $1.65/mm Btu ($9.9/boe). Both prices were distinctly marginal from a fully accounted profitability perspective. US gas prices have been depressed by a powerful cocktail of burgeoning supply and lacklustre demand. The former reflects rapidly rising by-product gas production in the shale oil basins of the Great Plains and Texas while the latter stems from several factors. These include competition from renewables in power generation, a weak industrial economy and generally mild weather conditions.

LNG prices hit by a supply glut and slowing demand growth: International LNG prices came under heavy pressure in 2019 driven by a supply glut and slowing demand growth. By end 2019 the East Asia JKM (Japan, Korea Marker) marker spot price was down to about $5.60/mm Btu ($34/boe). This was 40% below a year earlier and around the lowest price on record for the time of year. Rising supply reflected new capacity coming on-stream in several places but most notably the US, Russia and Australia. Slowing demand growth stemmed from a combination of mainly mild weather conditions in east Asia, nuclear power generation capacity coming back on-stream in Japan, competition from renewables in power generation, slowing industrial activity and high inventory levels.

KEY CRUDE OIL MARKET DEVELOPMENTS IN 2019 AND EARLY 2020

The crude oil market was driven by seven powerful influences in 2019 as follows:

- A tightening supply/demand balance in 2019 following the market slackness of the previous year.
- The OPEC+(the plus primarily relates to Russia) production accord which targeted removing 1.2mm b/d from the marketplace.
- Falling production in Iran and Venezuela reflecting tightening US trade and financial sanctions plus in the case of the latter the atrophying of the production infrastructure. New sanctions on Iran were implemented as part of a wide-ranging strategy to roll back its nuclear programme and cease support for terrorist groups and renegade regimes in the Middle East. Venezuelan sanctions are effectively

aimed at overthrowing the regime of President Maduro in the light of allegations of vote rigging and other abuses of power.

- Slowing world economic growth which led to an increasingly lacklustre demand backdrop as 2019 progressed. Recessionary fears, however, eased noticeably in the fourth quarter of 2019 but have subsequently resurfaced due to the coronavirus epidemic in China.
- The Iranian missile/drone attack on the Saudi Aramco processing facilities at Abqaiq and Khurais in the Eastern Province of Saudi Arabia on September 14. The attack briefly resulted in a 20% reduction in world output and helped drain surplus supply from the marketplace.
- The emergence of an apparent truce in the US-China trade war late in the fourth quarter.
- The continuing strong upward trend in non-OPEC output very much driven by the US. This prevented a more pronounced tightening in the market than might have been expected given falling OPEC production.

General Soleimani assassination: On January 2, 2020 oil markets were rocked by yet another dramatic development in the Middle East. This time it was the US assassination of General Qassem Soleimani, the commander of Iran's elite Revolutionary Guard Quds Force and Abu-Mahdi al Muhandis, an Iraqi militia commander in an airstrike near Baghdad airport. General Soleimani was also believed to be the leading Iranian military strategist and the architect behind proxy wars in the Middle East. He ranked number two as a political figure in Iran to the Supreme Leader, Ayatollah Ali Khamenei. Significantly, the Ayatollah threatened 'severe retaliation'.

Iranian missile attack on US bases: In response to the assassination of General Soleimani, Iran launched missile attacks on two US bases in Iraq on January 8, 2020. Although facilities were damaged there appear to have been no serious casualties. President Trump made light of the affair. Furthermore, the missile attack was overshadowed by the downing of a Ukrainian airliner by Iranian missiles. This event together with the initial denials tended to discredit the Iranian leadership not only internationally but also domestically.

Further Iranian response possible: The key issue now is whether Iran takes further action against the US in response to the Soleimani assassination. While a direct confrontation with the US through, for example, a closure of the Straits of Hormuz would appear unlikely due to a major firepower disadvantage, a more surreptitious venture involving a tit for tat assassination of a prominent person via a proxy is a possibility in our view. President Trump, however, has shown that he has no interest in new military entanglements in the Middle East. In all likelihood, the threshold for a US response to Iranian provocation is very high.

Coronavirus epidemic: Towards the end of January commodity markets, including petroleum, were dominated by the onset of the coronavirus epidemic in Wuhan, Hubei province east-central China.

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

Source: EIA

PRICE TRAJECTORY

2019 Q1------: Crude oil in late December 2018 was trading at depressed prices with Brent and WTI around $51/barrel and $45/barrel respectively. There was, therefore, considerable carryover weakness going into January 2019. The trend, however, quickly strengthened driven by increasingly bullish sentiment surrounding the OPEC+ production accord. In the first quarter of 2019 Brent averaged $63.1/barrel while WTI came in at $54.8/barrel. Although well up on late December 2018 levels, both averages lagged fourth quarter levels of $68.3/barrel and $59.6/barrel respectively.

------and early Q2 strengthening trend: Brent and WTI continued to firm early in the second quarter of 2019 supported by tightening US sanctions regimes on Iran and Venezuela. In the case of the former, sanctions were probably tightened more sharply than expected with the aim of reducing Iran's crude and natural gas exports to zero. Brent and WTI hit around six-month highs of $74/barrel and $66/barrel in late April. The trend weakened noticeably over the next four months. This was driven by a softening demand backdrop reflecting the emergence of an increasingly sluggish industrial economy globally. An intensifying US-China trade war also weighed on market sentiment. Despite the weakness post late April/early May, Brent and WTI both trended higher between the first and second quarters of 2019. The averages for the second quarter were $69.1/barrel and $59.9/barrel for Brent and WTI respectively.

Brief price surge in September following Iranian attacks on Saudi facilities: Prices bottomed in early August. Brent and WTI plumbed approximate seven-month lows of $55/barrel and $51/barrel respectively. Over the following six weeks or so prices trended modestly higher with Brent hitting around $65/barrel and WTI $58/barrel on September 9/10. The market was hit by the proverbial thunderbolt on September 14 in the form of two Iranian attacks on Saudi Aramco's key processing facilities at Abqaiq and Khurais. This briefly resulted in a 20% surge in Brent to $72/barrel and WTI to $62.7barrel. Reflecting expeditious repairs and an absence of retaliatory action by the Saudis and the US, the outage proved fleeting which prevented the price surge from being sustained. By end September Brent and WTI were down to $60.8/barrel and $54.1/barrel respectively or roughly back to pre-attack levels.

Upward trend in Q4 2019: In the fourth quarter of 2019 light crude benchmark prices trended steadily upward. Brent reached a high for the period of $69.7/barrel on December 19 while WTI peaked at $61.8/barrel on December 27. For the fourth quarter Brent and WTI averaged $63.4/barrel $57.0/barrel respectively. The upward trend in the fourth quarter reflected a broader trend in commodity prices and was driven in part by an easing of recessionary fears, in part by a truce in the US-China trade war and in part by growing tension in the Middle East between the US and Iran.

Price boost in early January 2020 following assassination of Gen Soleimani: Following the assassination of General Soleimani on January 2 light crude prices, not surprisingly, were given a significant boost. Brent and WTI peaked on January 6/7 at approximate seven-month highs of $70.3/barrel and $63.3/barrel respectively. The price surge proved short-lived much as had been the case at the time of the attack on the Saudi facilities at Adqaiq and Khurais. The market took the position, correctly it seems, that there would be no major escalation in hostilities between the US and Iran and consequent disruption to supplies at least in the near-term. Bearishness probably also reflected burgeoning non-OPEC supplies.

Sharp downward trend in second half of January driven by coronavirus outbreak and excess supply concerns: Since the peak in early January, the trend has been consistently downward with Brent and WTI trading at around $58.2/barrel and $51.6/barrel at end month. These prices were down 17% on the highs in early January. The downward trend was initially driven by general concerns about an over-supplied market and specifically in the US falling product prices particularly for gasoline.

In the second half of January fears relating to the potential impact on consumption in China of the coronavirus outbreak emerged with a vengeance. Light crude prices came under heavy with Brent and WTI dropping to about $54.0/barrel and $49.9/barrel on February 4. These prices were down around 21% on the early January 2020 highs and approximate 13-month lows.

PRICE SPREADS

BRENT-WTI

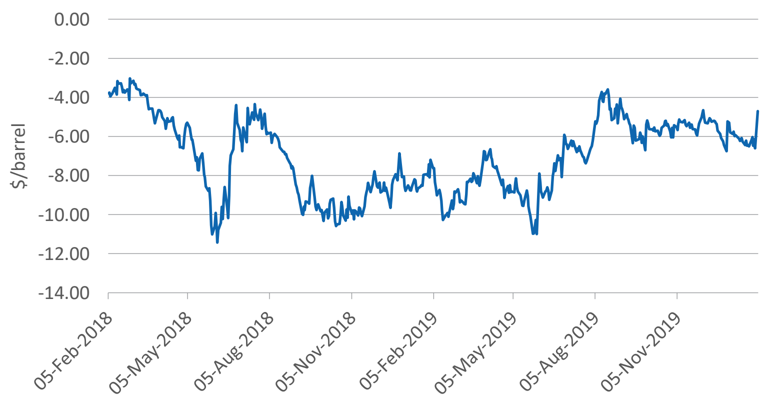
Narrowing Brent-WTI spread between H1 and H2 2019: The Brent-WTI spread (WTI discount), the most influential of the light crude benchmarks, averaged a historically elevated $8.3/barrel and $9.2/barrel in the first and second quarters of 2019. After narrowing sharply in the third quarter to $5.5/barrel, the Brent-WTI spread widened to $6.6/barrel in the fourth quarter. During the fourth quarter, the spread trended upwards and in December averaged $6.7/barrel. For 2019 as a whole, the Brent-WTI spread averaged $7.4/barrel, up from $6.1/barrel in 2018. The former was the widest annual WTI discount since the $10.8/barrel of 2013.

Narrowing trend in H2 reflected falling inventories at Cushing: In the first half of 2019 the elevated spread reflected rising inventories at the Cushing tank farm, the settlement point for NYMEX WTI crude. Driving inventories were rising production in the Permian Basin and pipeline constraints to the Gulf Coast refining centres, thereby diverting supply to Cushing. The narrowing WTI spread in the third quarter of 2019 was mainly driven by a reversal of the earlier upward trend in Cushing inventories subsequent to new pipeline capacity coming on-stream in the Permian. Signs of slowing US production growth and, a growing body of evidence on declining well productivity in the tight reservoir basins of Texas and the Great Plains may also have been contributory factors.

Widening during Q4 stemmed from Middle East geopolitical tension and the OPEC+production accord: The widening Brent-WTI spread during the fourth quarter of 2019, we believe, derived principally from rising geopolitical tension in the Middle East relating to the US and Iran and the OPEC+accord in December to cut a further 0.5mm b/d of production. It should be noted here that crude prices on the eastern side of the Atlantic Basin tend to be more sensitive to developments in the Middle East and OPEC than the geographically insulated US Mid-continent.

Post Soleimani assassination spike to $7/barrel: In early 2020, following the assassination of Iranian General Soleimani, the Brent-WTI spread was around $7/barrel. Subsequently, the spread narrowed modestly and in late January was running at about $6.6/barrel. For comparison, spot pipeline tariffs for light oil from Cushing to the Houston area refinery complex are around $2.25/barrel based on trade data. There is therefore a profitable arbitrage by moving oil from Cushing to the Gulf Coast where prices are more in line with Brent. In the early days of February, the Brent-WTI spread narrowed sharply and on the 6th was at $4.2/barrel.

EXHIBIT 3: BRENT - WTI SPREAD ($/BARREL)



Source: Thomson Reuters

WTI (CUSHING)-WTI (MIDLAND)

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). Historically, WTI Midland has sold at a discount of a dollar or two to WTI Cushing but in recent years, prior to the opening of new pipelines in the Permian, it has at times been closer to $5/barrel reflecting surging production in the basin. During the fourth quarter of 2019 the WTI discount was running at $3.6/barrel which was roughly inline with the earlier months in 2019.

The WTI Midland discount returned to more normal levels in 2019 due to the substantial expansion of takeaway pipeline capacity from the Permian Basin to the refining centres and export terminals of the Gulf Coast. We estimate that the expansion from late 2018 to end 2019 was around 2.5mm b/d. The most recent addition was the Phillips 66/Enbridge 900,000 b/d Gray Oak pipeline which connects Orla Texas in the west of the Permian Basin and the Eagle Ford zone with Corpus Christi and the Houston refinery complex, including Phillips Sweeney refinery. About 95% of the capacity additions have been directed at the Gulf Coast with the balance in the form of the Plains All American Sunrise expansion aimed at Cushing. Based on industry data, we believe pipeline takeaway capacity from the Permian is about 4mm b/d.

Greater Permian pipeline capacity has enabled WTI-LLS spread to narrow: Rising takeaway capacity in the Permian has enabled the WTI Midland discount to the light, low-sulphur crudes available on the Gulf Coast to be cut significantly since early 2019. The discount to Louisiana Light (similar in specification to WTI and Brent), for example, fell from over $10/barrel in the first half of 2019 to about $7.3/barrel in late January 2020. Producers in the Permian now have the opportunity, due to greater pipeline capacity, to capture prices approaching those of Brent on export shipments. Based on trade data, the spot tariff for pipeline shipments of light crude from Midland to the Gulf Coast can be as low as $1.35/barrel.

WILLISTON (BAKKEN) SWEET-WTI CUSHING SPREAD

Williston light discount to WTI normal at $10.7/barrel: The Williston Basin in North Dakota and Montana is one of the most remote oil producing zones in the Lower 48 states. The crude sourced from the Basin is, generally high-grade with a light (high API), low sulphur specification. It sells at a significant discount to WTI Cushing reflecting logistical constraints and distance from Midwest and Gulf Coast refining centres. Local refining capacity is modest in scale and consists of Phillips 66 67,000 b/d Billings, Montana facility.

In late January 2020, Williston Sweet was selling for $47.8/barrel, a discount of $10.7/barrel to WTI Cushing. This is broadly in line with the discount of recent months, although much narrower than the $17.6/barrel of a year earlier when Williston Sweet was trading at $34.8/barrel. Clearly, the 51% increase in price for the grade has boosted profitability from the marginal levels of a year previously.

At the Clearbrook Hub, 450 miles east of Billings, in north western Minnesota Bakken light oil was trading at $53.1/barrel in late January 2020. This reflected a discount of a mere $1.1/barrel to WTI.

SWEET-SOUR SPREADS

Backdrop

Sweet-sour spreads----Due to the ease of refining into premium-priced products, light-sweet grades, such as Brent, normally trade at a premium to sour-heavy grades. Unusually during 2018 and early 2019 historical sour discounts tended to narrow or even flipped to premiums from time-to-time. This stemmed from several factors. On the supply front the availability of sour crudes tightened due to US sanctions on two large producers notably Venezuela and Iran, OPEC production cutbacks and the appearance of contaminants in

Urals grade crude. It should be noted here that refineries along the US Gulf Coast have often been reconfigured in recent years to use relatively low-cost, heavy-sour feedstock.

Within a Mediterranean context, sour crude demand was also given a sizeable boost in 2019 from the start-up of Star Rafineri's 200,000 b/d refinery at Aliaga, Turkey. The refinery, owned by the Azeri state oil company SOCAR and the Turkish petrochemical company PETKIM, is easily the largest such facility to be commissioned in Europe/Mediterranean in the past 40 years.

------have returned to normal of late partly due to tighter regulations for marine fuel sulphur content: A notable feature of oil markets in recent months has been a swing back to more normal or indeed wider than normal sour discounts. This has been driven in large part by increasing demand for light-sweet crude in the run-up to the IMO's (International Maritime Organisation, a UN agency) directive to sharply reduce the sulphur content of marine fuel from 3.5% to 0.5%. The directive came into force on January 1, 2020. According to ExxonMobil, the sulphur content of heavy fuel oil (HSFO) for marine bunker applications was around 2.7% in 2019. The world market for marine bunker fuels is about 4.3mm b/d or 4% of total petroleum demand. Based on industry reports, before 2020 bunker fuel demand was split 75% HSFO and 25% MGO (marine gas oil) which is similar to diesel.

Low cost high sulphur fuel oil has been the marine fuel of choice: The attraction of HSFO (high-sulphur fuel oil) is low-cost reflecting that it is residual product obtained after processing high-value light products such as gasoline and middle distillates. Over the past five years high-sulphur fuel oil has sold at a discount of about $255/tonne to MGO, according to ExxonMobil.

In late 2019 prices for marine bunker fuels compliant with the new IMO directive surged. This reflected in part rising crude prices but principally a scramble for compliant fuel. Based on industry reports, ex-Rotterdam prices in early January 2020 were running at about $580/tonne for VLSFO (very low sulphur fuel oil) and $610/tonne for MGO. Compared with mid-November 2019 levels, these prices were up about 9% for MGO and 16% for VLSFO. The VLSFO premium to HSFO is $300/tonne while for MGO it is $330/tonne. The IMO directive, therefore, imposes a substantial increase in shipping costs bearing in mind that fuel is the largest cost category in operating a vessel.

High sulphur fuel can no longer be used in unmodified marine engines: Compliance with the IMO directive requires ship owners to cease using HSFO as a bunker fuel in unmodified marine engines. There are presently four ways in which compliance can be achieved with the directive as follows:

- Use marine gas oil (MGO) which has the virtue of a very low sulphur content and burns with low emissions of NOX (nitrogen oxide) and particulates. The disadvantage is clearly cost.

- Use VLSFO (very low sulphur fuel oil) which has the advantage of being IMO compliant without engine modification. Currently, it also sells at a modest discount to MGO. The EIA and marine industry sources believe that as the production of VLSFO increases the discount to MGO will widen resulting in it becoming the fuel of choice for marine applications. At present, there is a lack of availability of VLSFO so in the short to medium term there may be no alternative to using MGO as a compliant bunker fuel.

- Install exhaust gas cleaning systems or scrubbers and continue using low-cost HSFO. Based on survey data, ExxonMobil has suggested that 19% of shipowners will adopt this option. Key drawbacks to the scrubber route are the hefty direct cost of installation at around $4m/vessel, the time required for this purpose and the need to dispose of waste material en-route. Longer term there is also an issue concerning the continuing widespread availability of HSFO given that it is in the throes of becoming a non-compliant bunker fuel.

- Use LNG (liquified natural gas) which again has the virtue of being a compliant low-cost bunker fuel. The problems are lower fuel consumption compared with much higher energy density distillates, limited availability at shipping hubs and the difficulties and expense of storage.

Sweet crudes are required to produce low sulphur fuel in unsophisticated refineries: To produce MGO or VLSFO in unsophisticated refineries requires sweet crudes such as Brent, WTI or Tapis (an ultra-sweet Malaysian crude with a sulphur content of 0.04%) ideally with sulphur contents of 0.5% or less. Typically, these light, sweet grades produce a much greater yield of high margin refined products than sour grades.

While it is possible to convert HSFO to distillates, the process requires costly equipment such a coker and involves a long lead time for installation. Capital costs are at least $1bn per refinery and lead times are over five years according to ExxonMobil. However, once suitably equipped complex refineries can use low cost feedstock and boost both yields and variable margins. Logically one consequence of the tightening IMO sulphur content standard for bunker fuel, other things being equal, is softening demand for high sulphur feedstock. This should be reflected in a widening discount to the light-sweet grades.

BRENT-URALS

Key sweet-sour European spread Brent-Urals: 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 than Brent. Historically, Brent has traded at a premium of $2-3/barrel to Urals.

The Brent premium has been historically wide of late: After tracking very close to Brent through the first half of 2019, the Brent premium started to widen in the third quarter. The trend continued in the fourth quarter and towards late 2019 the premium was around $8.5/barrel, well above the historical norm. By late January 2020, however, the Brent premium to Urals had narrowed to $4/barrel. An historically high premium to Urals may persist until there is a sustained increase in supplies of VLSFO. To maintain the viability of Urals crude it may also be necessary to change the blend to contain more light-sweet crude.

LOUISIANA LIGHT-MARS AND MAYA

The key US Gulf Coast sweet-sour benchmarks are Louisiana Light-Mars and Louisiana Light-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. It normally trades at a discount of a dollar or two to the higher-quality Louisiana Light which has a sulphur content of only 0.37%. Maya is a heavy sour crude sourced from 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.

Tight supply of heavy-sour crudes along Gulf Coast: In the closing months of 2019 Mars was selling at a historically wide discount of $2-$3/barrel to Louisiana light. Maya, however, was trading roughly in line with Mars and consequently at a historically narrow discount to Louisiana Light. In late January 2020, Mars and Maya were trading at discounts of $2.3/barrel and $2.9/barrel respectively to Louisiana Light. Along the Gulf Coast the historically narrow Louisiana-Maya spread of late may reflect the underlying tightness in heavy-sour supply following the imposition of swingeing US sanctions on Venezuela and the continuing downward trend in Mexico production.

WCS-WTI SPREAD

WCS (Western Canada 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 gravity is about 20° while the sulphur content is 3.4%. This compares with 40° and 0.24% for WTI. Reflecting the variance in specification and the remote sourcing, WCS has historically sold at a $10-20/barrel discount to WTI. 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 using heavy-sour feedstock.

In principle, WCS could also be used by sophisticated refineries along the Gulf Coast which would solve the problem of the declining availability of heavy crude in the region following the loss of Venezuelan exports and Mexican field depletion. Constrained pipeline capacity from Alberta, however, restricts the flow of WCS to the Gulf Coast.

WCS discount narrowed sharply in early 2019 in response to Alberta cutbacks----WCS is usually one of the lowest priced crude grades available. During early 2019 the price trended sharply higher from the ultra-depressed levels of late 2018 of $12-15/barrel. WCS peaked in late April at $55.8/barrel, a discount of $10.4/barrel to WTI. The price surge reflected Alberta government directed production cutbacks following an unprecedented inventory build-up in the province and a lack of takeaway capacity. The petroleum industry in Alberta has been consistently thwarted in expanding pipeline capacity over several years by a host of political, environmental, landowner, permitting and indigenous group objections.

------but has subsequently widened sharply: As the policy of production curtailments was gradually eased, WCS again came under significant price pressure during the third quarter and early in the fourth quarter of 2019. In early November a key negative was an extended cessation of operations in the Keystone XL pipeline following a spillage in North Dakota early in the month. WCS plumbed a recent low in late November 2019 of $30.9/barrel, a discount of a hefty $24/barrel to WTI. This was well below the massive $45/barrel discount in late November 2018 but still unusually high by historical standards. WCS trended higher in December and early January 2020 when it was trading at about $40/barrel. The discount to WTI, however, remained at about $24/barrel. In late January 2020 WCS was trading at a historically depressed $32.7/barrel, a discount of $23/barrel to WTI.

The underlying problem is a lack of takeaway capacity: Clearly, if Alberta oil sands production capacity continues to outpace takeaway pipeline capacity WCS-WTI spreads will remain historically wide. Progress remains challenging on all three Alberta pipeline projects. Work on the Federally owned Trans Mountain expansion between Edmonton and Burnaby east of Vancouver, British Columbia may however be poised to commence in earnest. When complete, this would allow pipeline capacity to be boosted by 300,000 b/d and would facilitate the shipment of Alberta crude to east Asia for the first time. The Trans Mountain expansion could be in operation by end 2022.

Enbridge Line 3 work completed in Canada but still permitting issues in the US: Work on Enbridge’s Line 3 replacement and expansion was completed on the Canadian section from Hardisty, Alberta to Gretna, Manitoba in November 2019. The US section from the Manitoba/North Dakota border to Superior, Wisconsin, however, has not been built reflecting interminable permitting delays particularly in Minnesota. Importantly in early February the upgraded Line 3 received Minnesota regulatory approval so work to complete the pipeline could, in principle, commence. Various groups however continue to oppose Line 3. Enbridge had been suggesting an end 2020 start-up for the upgraded Line 3 but this is looking highly optimistic. Probably we are now looking at late 2021. Compared with the existing pipeline, which dates back to the 1960’s and is only operating at 50% of capacity on safety grounds, the new Line 3 will boost capacity from Alberta by 370,000 b/d.

Keystone XL pipeline project still suffers from intractable objections: Of the three Alberta pipeline projects the Keystone XL arguably suffers from the most intractable political and legal objections. Keystone XL offers a direct route (there is already an indirect route) from Hardisty to Steele City, Nebraska and ultimately Cushing and the Gulf Coast. It would boost takeaway capacity from Alberta by 900,000 b/d. Keystone XL has US federal support and has received approval by Nebraska's highest court but to no avail. Legal objections continue to be filed with the aim of forcing the promoters to reapply for approval. The underlying issue is that there is an unholy alliance of landowners, indigenous groups and environmentalists that object to Keystone XL and more broadly the Alberta oilsands on principle. It remains unclear when or indeed if construction work on Keystone will commence.

Rail shipments have been increasing sharply from Alberta influenced by the wide WCS discount: A short-term expedient to solving the pipeline bottleneck crisis facing the Alberta oil sands producers is to ship by rail. Indeed, shipments by rail have been expanding along with terminal, rail car and locomotive capacity. According to industry reports, they are now running at 500,000 b/d or more, which is roughly double that of a few months ago. Until recently, at least, the economics of railing WCS to the Gulf Coast appeared viable given railage of around $22/barrel and prevailing prices along the Gulf Coast for heavy-sour oil of around $54/barrel. The recent dip in prices to about $48/barrel however has made the exercise significantly more marginal. We believe pipeline costs from Fort McMurray in northern Alberta to the Gulf Coast would be more like $12/barrel which would greatly enhance oil sands economics. While some oil is shipped via the indirect Keystone XL the volumes are insufficient relative to oil sands production capacity.

FORWARD CURVES

Flip to contango: Structurally the forward market for Brent and WTI changed fundamentally in early February 2020. Rather than the backwardation (near month prices higher than for the more distant dates) that has characterised the forward market since at least July 2019, the front-end of the curves are now essentially flat for all dates through late 2022. This is consistent with the sharp and unexpected drop in China demand of late and apparent sizeable inventory build-up. The middle section and backend of the curves reflect a mild contango (near month prices lower than for the more distant dates) pointing to expectations of a tightening market. The upward slope of the curve may provide a moderate incentive for inventory building.

Downward shift: In addition to the shape of the curve changing of late, there has also been a pronounced downward structural shift reflecting the approximate 20% fall in spot prices since the recent early January 2020 highs.

BRENT

Front end curve backwardation in late 2019 and indeed through early January reflected seasonally buoyant demand for light sweet crude and generally falling inventories. Demand for the light grades was boosted by the need for shipowners to comply with the new IMO standards for low-sulphur marine fuel. This issue combined with fears of Middle Eastern disruption to supplies has, however, now been completely overwhelmed by the sudden and unexpected plunge in Chinese demand related to the coronavirus epidemic.

As of early February, the front-end of Brent forward curve commenced for April 2020 shipments at $54.5/barrel, roughly equivalent to spot. The curve was in marginal contango over the next two months taking the forward price to $54.7/barrel. For all dates between July 2020 and January 2021 the curve reverted to mild backwardation with the forward price at the latter date being $54.3/barrel. Through the middle section and back end of the curve mild contango prevailed. The curve terminates in the first quarter of 2029 at $58.2/barrel, a modest $3.7/barrel spread to spot.

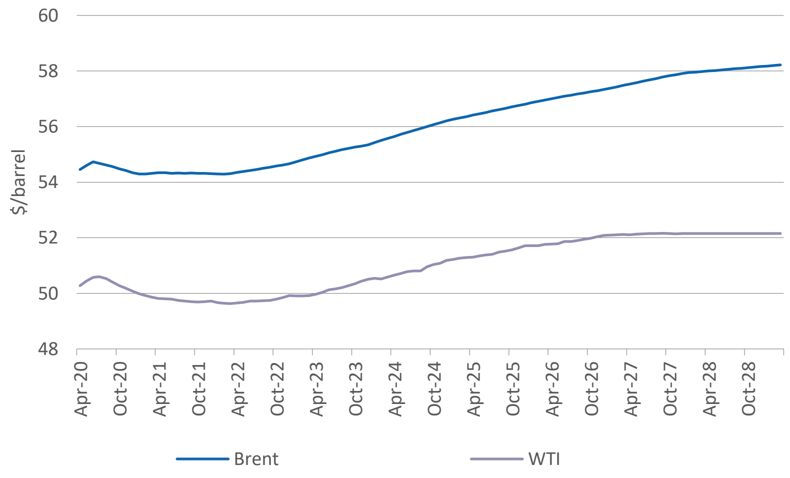
WTI

The WTI forward curve shows a similar picture to Brent. However, the WTI backend is flatter. For shipments in April 2020 the forward price is $50.3/barrel or similar to spot. Very mild contango takes the forward price to $50.6/barrel in July 2020 before switching to mild backwardation over the following 20 months. For March 2022 shipments the forward price was $49.6/barrel. Between April 2022 and July 2027, the curve was in mild contango taking the forward price to $52.2/barrel at the latter date. The backend of the curve to the first quarter of 2029 is flat at $52.2/barrel. The spot to March 2029 spread was a modest $2.0/barrel based on the early February 2020 forward curve.

Taking the period April 2020 to March 2029 the forward curves reveal a widening of the WTI discount from $4.2/barrel to $6.0/barrel. This is well within the historical range but the tendency for the spread to widen post 2025 appears surprising in the light of rising pipeline capacity from the Permian to the Gulf Coast and general expectations of scaling back of tight reservoir development activity in the US shale basins.

Bearing in mind the lead times involved in oilfield development, the forward curve is arguably of greater relevance for petroleum industry investment than the spot price. Given the relatively short lead times associated with US onshore shale oil development, however, the front-end of the curve is more relevant than the backend in making investment decisions. Looking at the front-end of the WTI curve between the first quarters of 2020 and 2023 the average forward price is around $50/barrel. This is entering marginal territory for US tight reservoir development activity even where WTI pricing applies. Clearly, in the case of sub-WTI pricing in the more remote basins such the Williston (Bakken), development economics would appear distinctly marginal given current forward prices.

EXHIBIT 4: BRENT AND WTI FORWARD CURVE ($/BARREL)



Source: Thomson Reuters

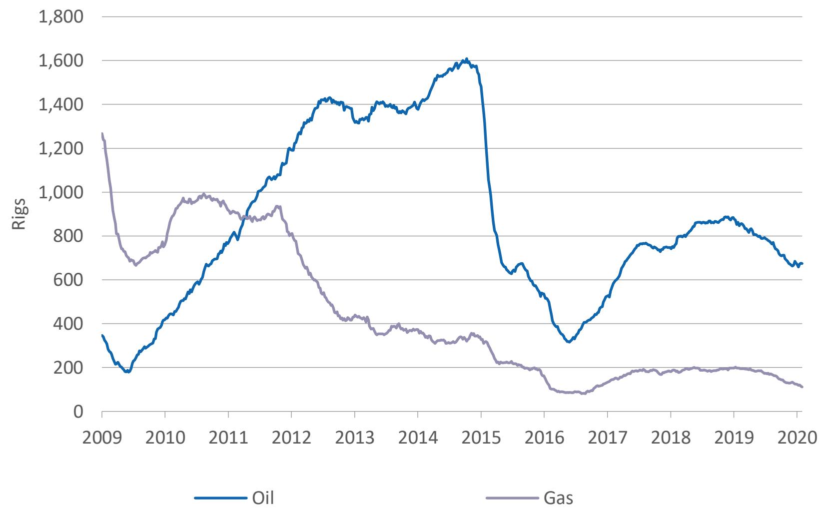
US SCENE

DRILLING ACTIVITY

Recent oil-directed trends

Downward trend in drilling activity----: The trend in the US onshore oil-directed rig-count remains weak but has shown signs of stabilising over the past few weeks. Based on Baker Hughes data, the rig count in the week ended January 24, 2020 came in at 676, down 22% or 186 on a year earlier but was broadly unchanged from early November 2019 levels. Compared with the recent high of 888 on November 16, 2018, the rig-count in the week to January 24 was down by 24% or 212. Despite the weakness since November 2018, the rig-count in early 2020 was well above the low in recent years of 316 in May 2016.

EXHIBIT 5: BAKER HUGHES US RIG COUNT (RIGS)



Source: Baker Hughes

-------reflecting increasingly tight financial constraints on mid-tier E&Ps: The weak trend in the oil-directed rig count over the past 12 to 15 months reflects cutbacks in development activity in the principal US tight reservoir basins. Mid-tier and junior publicly listed E&P concerns have increasingly been subject to financial constraints and pressure from shareholders to boost returns and free cash flow. Another problem for developers has been declining well productivity in intensively drilled zones. Until recently, the strategic thrust of mid-tier oil producers has emphasised production, but the new objectives are operational cash flow, paying down debt and dividends.

Production has continued to grow strongly despite decline in drilling activity: An interesting issue concerning the trend decline in the rig count over the past 12 to 15 months is the reconciliation of this with the continuing strong upward trend in US oil production. Growth in crude alone, note, has been about 1.2mm b/d over the past year. It might have been thought that a decline in the rig count of the magnitude reported would rapidly induce a decline in production. This applies particularly bearing in mind very high rates of depletion in the tight reservoir basins of the Great Plains and Texas.

High-grading and completing drilled but uncompleted wells have supported production: The explanation to the apparent rig count/production conundrum, we believe, reflects a combination of lags between drilling and production, the completion of drilled but uncompleted wells and the high-grading of drilling opportunities. It should be noted that there is a large inventory of uncompleted wells available which can be brought on-line for production after fracking and installing secondary lift. As far as high-grading is concerned, E&P concerns maybe focusing more sharply than previously on drilling opportunities with potentially above average well productivity characteristics. In the same vein, there has possibly also been a tendency to focus on the more productive basins. Interestingly, the EIA in its latest Drilling Productivity Report points to the trend in 30-day initial production rates for new wells in all major basins still being upward. This is attributed to technical advances in drilling and completion and focusing development on the most productive zones (high-grading). Significantly, the EIA also pointed to declining drilling times which can facilitate cutback in the drilling rig fleet.

Despite the ongoing advances in drilling and completion technology, it would still be surprising if the drop in the rig rate plus declining well productivity in mature development zones was not reflected in slower production growth in 2020 and particularly 2021.

Tight reservoir rig-count

The Permian remains the basin of choice in the US-----: The Permian Basin (Texas and New Mexico) is the US tight reservoir zone of choice for oilfield development. This reflects extremely favourable geological characteristics with the key one being thick multiple stacked formations of sandstone, limestone and shale. Multi-stacking enables high reservoir recovery rates from a single well with the potential for industry beating development and production costs.

-----but the rig count has also slipped here: The Permian oil-directed rig count has slipped from the November 2018 high of 493 but remains elevated from a longer-term perspective. For the week ending January 24, 2020 the Permian rig count was 405, 60% of the US total well up on the 56% of a year earlier. Compared with a year ago, the Permian rig count was down 18% on the November 2018 high.

Elsewhere, in the other four major US tight reservoir basins/zones the trend in the oil-directed rig count has been flat to down in recent weeks. Rig counts at January 24, 2020 came in as follows: Eagle Ford (Texas) 67 down 7% YOY, Williston (Montana and North Dakota) 53 down 9% YOY, DJ-Niobrara (Colorado and Wyoming) 19 down 39% and Cana-Woodford (Oklahoma) 21 down 66% YOY.

Recent gas-directed drilling trends

Activity continues to trend down-----: US natural gas-directed drilling has continued trending down in recent weeks and is running at a very depressed level historically. For the week ended January 24 the Baker Hughes rig count was 115, down 42% on a year earlier and approaching the multi-year low of 81 in 2016. Interestingly, the gas-directed rig count peaked at 1,606 in the third quarter of 2016. We believe that residual levels of drilling activity largely reflect situations where drilling commitments apply.

-------reflecting depressed gas prices: The gas-directed rig count continued to be heavily impacted by the depressed gas price backdrop in 2019. The Henry Hub benchmark price was down to about $1.89/mm Btu in late January 2020 which is the lowest price for the time of year since 1999 and significantly below fully accounted operating and development costs which we believe are closer to $2.5/mm Btu. Note, at the Waha hub in the Midland Basin gas was trading at $0.60/mm Btu in late January 2020, although it needs to be remembered that much of the gas in the region is produced as a by-product of oil production. Given extremely marginal economics, gas producers have been pretty much shut out of the public markets for debt and equity. Reflecting the challenging industrial and financial backdrop a number of natural gas producers have filed for bankruptcy over the past year. These include high-profile concerns such as Sanchez Energy, Legacy Reserves and EP Energy.

Production however continues to surge due to by-product output from oil wells: US natural gas production continued to surge in 2019 despite the plunging rig count. For the year there was a gain of about 10% to a record 98.99 bcf/d, according to the EIA. The apparent dichotomy reflected the continuing surge in by-product gas production in the oil shale basins in general and the Permian in particular. We believe that US natural gas production growth will slow sharply in 2020 reflecting a combination of unattractive economics, the lagged impact of declining development activity, severe financing constraints and a slower rate of oil production growth in the tight reservoir basins.

M&A ACTIVITY

Major oil patch M&A deals: 2019 was an important year for M&A in the US shale oil patch. The key drivers centred around securing acreage, development potential, production and cost synergies, particularly in the Permian Basin. The largest move was Occidental's $38bn acquisition of Anadarko Petroleum in May. Other major oil patch acquisitions in 2019 included Parsley Energy and Jagged Peak Energy, Callon Petroleum and Carrizo Oil & Gas, Whiting Petroleum and Abraxas Petroleum and most recently WPX Energy and Felix Energy.

Recent WPX $2.5bn acquisition of Felix Energy: Tulsa-based WPX, a major player in the Permian, announced its $2.5bn ($0.9bn cash, balance WPX paper) agreed deal to buy Felix on December 16. Felix owned by the Houston-based EnCap Investments LP private equity concern, has a highly significant 58,500 net acres on the eastern side of the Delaware sub-basin and 1,500 gross drilling locations. The Delaware sub-basin, note, is one of the three structural features defining the Permian with the other two being the Midland Basin and the Central Basin Platform which separates the Midland and Delaware sub-basins. The acquisition boosted WPX's Permian acreage by 47% to 184,000 acres while the drilling locations increased by 44% to 4,900. Importantly, Felix's production is running at about 60,000 boe/d (70% oil) which will increase WPX's output by a third to 241,000 boe/d.

WPX suggests that the acquisition cost is equivalent to a modest 3.5X EBITDA, assuming WTI at $50/barrel. The cost per acre is $42,735 or slightly above the level Pioneer Resources, one of the leading producers in the Permian, has suggested has been the recent average deal price in the Permian of around $38,000/acre. Significantly, WPX has indicated that the Felix deal will be earnings accretive immediately. The stock market reaction to WPX's s Felix deal was positive, which has not always been the case in the US oil patch of late.

US oil patch M&A likely to continue at a high level in 2020: M&A activity in the US oil patch and particularly in the Permian Basin seems likely to continue at a high level in 2020. This reflects partly cost and financial pressures but also stems from the prolific nature of the Permian and the availability of acreage and development potential cheaply. Chevron would appear to be a leading candidate to make a major move given its decision not to pursue the acquisition of Anadarko in 2019. ExxonMobil may also attempt to bulk-up its already sizeable position in the Permian held through XTO Energy. Its development potential was considerably enhanced in 2017 through the purchase from the Bass family of Fort Worth, Texas of 275,000 acres in New Mexico.

WHAT ABOUT THE DEMOCRATS?

Leading candidates are hostile to the petroleum industry: The three leading Democrat candidates, Joe Bidden, Elizabeth Warren and Bernie Sanders, for the US Presidency in the November 2020 elections are all hostile to the interests of the petroleum industry. Joe Bidden, for example, in a recent Democrat presidential debate (Los Angeles December 19, 2019) has clearly indicated that he would be willing to sacrifice 'hundreds of thousands' of oil and gas industry jobs in the cause of the Green New Deal. Note, Joe Bidden is generally considered to be the most moderate and electable of the Democrat candidates for the presidency.

Potential fracking ban: Elizabeth Warren and Bernie Sanders have both stated that they would ban hydraulic fracturing or fracking not only on federal but also on state and private land. If such a ban was implemented, oil and gas production would rapidly go into a catastrophic decline given high depletion rates in the tight reservoir basins of Texas and the Mid-continent. Hydraulic fracturing at high pressure is required to enhance well flow rates and recoverable reserves, thereby potentially boosting returns. Without applying this critical technology, tight reservoir development would probably be uneconomic which would, of course, be the aim of a hydraulic fracturing ban.

Potentially disastrous implications for the petroleum industry and its suppliers: In addition to impacting those directly involved in the petroleum industry, a collapse in production and development activity would have major second order effects. Think here of a range of service industries including legal and financial, suppliers of machinery and OCTG (oil country tubular group steel products), auto distributors, real estate and state government tax and royalty revenues. Even if there was not an outright ban on hydraulic fracturing it seems likely that any Democrat presidential nominee chosen from the leading candidates would seek ways of raising the cost of oil and gas development. This might be achieved by tightening other regulatory requirements including permitting and emissions.

PRODUCTION

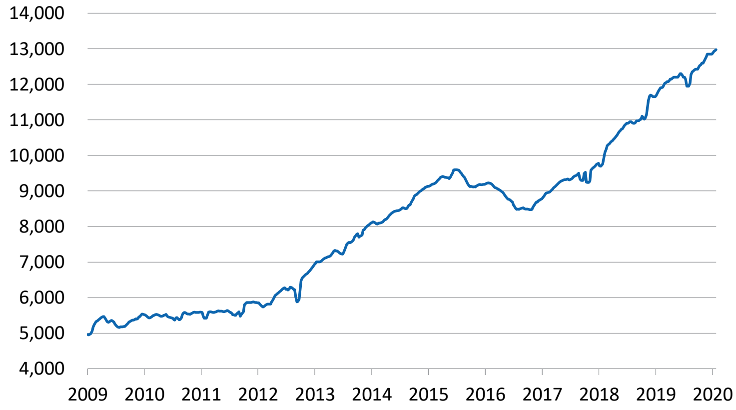
Crude oil trends

Record output and still rapid growth in 2019: US crude oil production on average in 2019 hit a record 12.24mm b/d according to EIA data. Growth for the year of 11.4% or 1.25mm b/d was slower than the 1.64mm b/d of 2018 but was nevertheless an impressive performance bearing in mind the exceptionally strong growth of recent years. It should be noted that US crude production has climbed 145% or 7.24mm b/d from the 2008 low of 5.00mm b/d. We believe the expansion in US crude production since 2008 has been unprecedented for what previously had been considered a mature petroleum province.

YOY growth slowed in H2: During 2019 the growth in US crude production slipped between the first and second halves. In the first and second quarters year-on-year growth came in at 15.0% and 14.9% respectively. This was followed by a slowing to 8.7% in the third and 7.9% in the fourth quarters. Production in the fourth quarter of 2019 was 12.83mm b/d, up 4.9% on the prior quarter. The slowing in the third quarter reflected to a large extent the impact of Hurricane Barry which reduced output in the Gulf of Mexico (GOM). Looking at the regional breakdown production in 2019 was down 2% in Alaska, 7% higher in the GOM and up 13.0% in the Lower 48. For the three regions production (mm b/d) averaged as follows in 2019: Alaska 0.47, GOM 1.89, Lower 48 9.89. Despite the third quarter weakness GOM output in 2019 was running at record levels reflecting high development activity.

Buoyant trend in late 2019 and early 2020: Based on EIA data, the trend in US crude production in late 2019 and early 2020 remained buoyant. Taking the four-weeks to January 17, 2020 production averaged 12.95mm b/d, up 9.7% on a year earlier. Growth in the Lower 48 and the GOM of 10.2% was slightly offset by a 3.2% decline in Alaska.

EXHIBIT 6: US CRUDE OIL PRODUCTION (B/D 000'S)



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

Tight reservoir production

Production was running at about 9.1mm b/d in late 2019: US crude oil production over the past year and indeed over the past ten has very much been driven by intensive tight reservoir development activity in Texas and the Great Plains. A supporting role has been provided in recent years by the GOM while Alaska has been in secular decline, reflecting the maturity of the zone. According to EIA data, tight reservoir oil production (crude and natural gas liquids) late in the fourth quarter of 2019 was running at about 9.1mm b/d. The Permian Basin accounted for 52% of tight reservoir liquids production over the period. The weightings of the next four largest tight reservoir plays, Bakken, Eagle Ford, Niobrara and Anadarko, were 17%, 15%, 8% and 6% respectively.

Natural gas liquids and hydrocarbon substitutes

NGL production also grew strongly in 2019: The US produces substantial quantities of natural gas liquids (NGL's) and renewable fuels in the form of ethanol and biodiesel. Growth has trended strongly upward in recent years largely as a consequence of the substantial quantities of wet-gas produced as a by-product of oil-directed development especially in the Permian Basin. An additional factor has been by-product liquids stemming from natural gas development activity in the Appalachian Basin. Based on EIA data, NGL production in 2019 was a record 4.88mm b/d, up 11.7% on 2018. In total, the production of NGLs and renewables, net of refinery gain, in 2019 was 7.14mm b/d, 5.9% higher than a year earlier.

US overwhelmingly the world's largest producer of hydrocarbons liquids: Taking crude oil, NGL's and renewables, total US oil production in 2019 was 19.38mm b/d, for a gain of 9.3% on 2018. Based on EIA data, the domestic supply of liquids was equivalent to about 95% of consumption for 2019 as a whole and 97% in the fourth quarter. As President Trump recently noted at the Davos Economic Forum, the US was overwhelmingly the world's largest oil producer in 2019. The next largest was Russia with output of 11.49mm b/d.

Forecasts

Slower but still significant growth expected in 2020/21: The EIA, although looking for a slowdown, is still forecasting very significant growth in US crude oil production in 2020 and 2021. For these two years production is forecast at 13.30mm b/d and 13.71mm b/d respectively for gains of 8.7% (+1.06mm b/d) and 3.1% (+0.41mm b/d). Not surprisingly, the EIA's production forecasts are driven principally by development activity in the tight reservoir basins of Texas and the Great Plains. In the Lower 48 (excluding the GOM) crude production is expected to advance by 0.95mm b/d to 10.84 mm b/d in 2020 and 0.42mm b/d to 11.26mm b/d in 2021. Excluding about 0.45mm b/d for heavy oil in California, these forecasts approximate to light oil mainly derived from tight reservoir formations. GOM production is forecast to increase by about 90,000 b/d in 2020 and to be roughly unchanged in 2021 while Alaskan production is forecast to rise by 10,000 b/d in both years.

US likely to be self-sufficient in 2021 for the first time in at least 50 years. US oil in production in total including NGL's, renewables and refinery gain is forecast by the EIA to come in at 21.08mm b/d and 21.69mm b/d in 2020 and 2021 respectively. This would imply year-on-year gains of 8.8% and 2.9% respectively. Based on the EIA scenario, US oil production would constitute 102% of domestic consumption in 2020 and 105% in 2021. We believe that this will be the first time in at least 50 years that US oil production has exceeded domestic demand.

EXHIBIT 7: US CRUDE OIL QUARTERLY PRODUCTION

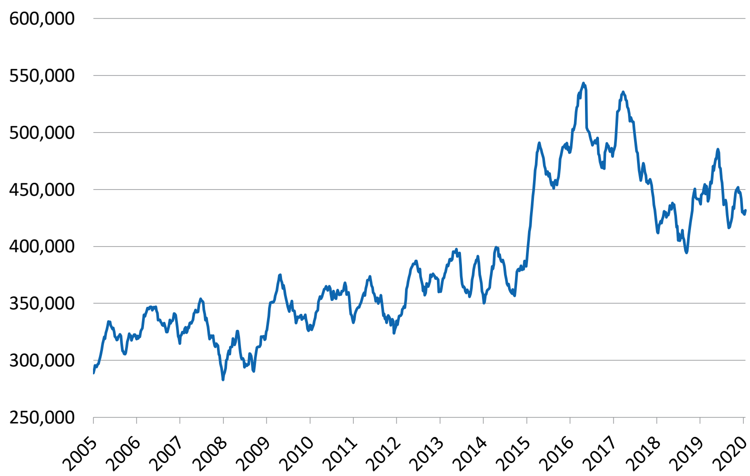
	Q1	Q2	Q3	Q4	Total
2018 mm b/d	10.27	10.54	11.25	11.89	10.99
YOY %	13.5	15.7	20.6	20.1	17.5
2019 mm b/d	11.81	12.10	12.23	12.83	12.24
YOY %	15.0	14.9	8.7	7.9	11.4
2020 mm b/d	13.20	13.31	13.29	13.41	13.30E
YOY %	11.8	10.0	8.7	4.5	8.7
2021 mm b/d	13.52	13.64	13.73	13.95	13.71E
YOY %	2.4	2.5	3.3	4.0	3.1

Source: EIA. Note: Data from Q1 2020 are forecasts.

INVENTORIES
Crude

Normal both absolutely and in terms of days' supply: US commercial crude inventories after advancing in late 2018 and through the first half of 2019 have subsequently trended down. However, as of late January 2020 they were well within the normal range for the time of year both absolutely and in terms of days' supply. For the week ended January 17, 2020 commercial inventories stood at 428.1mm barrels down 4% on a year previously and 12% on the recent early June 2019 high of 485.5mm barrels. Inventories were, in fact, in the middle of the range for the time of year. On a days' supply basis crude inventories on January 17 were equivalent to 25.2 against 25.6 a year earlier.

EXHIBIT 8: US CRUDE OIL INVENTORIES (THOUSAND BARRELS)



Source: EIA

Rising exports dampening trend in inventories: We believe crude inventories in recent months have continued to be dampened by the robust trend in exports and the expansion of pipeline capacity, particularly in Texas. These two factors have prevented the build-up of inventory despite buoyant production. The lifting of the ban on US exports of crude effectively provided a safety valve for the domestic petroleum industry.

EIA 2020 end year forecast well within five-year range: The EIA continues to look for a moderate upward trend in US crude inventories in 2020 driven by growth in domestic production and a subdued demand growth. The end year forecast of 461mm b/d, however, is well within the five-year range. It should be noted that given buoyant US production of light oil, still substantial imports of medium and heavy grades and the lumpy nature of imports, inventories are particularly difficult to forecast.

Cushing

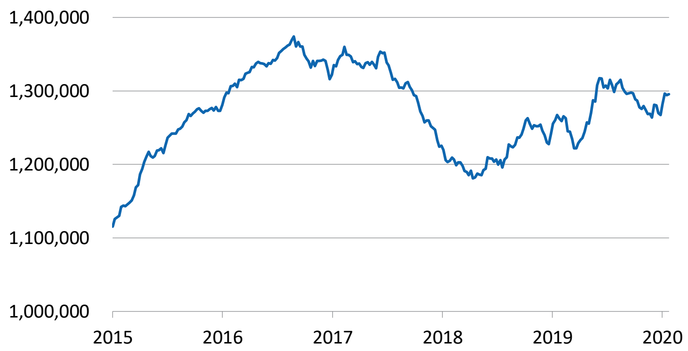
Inventories well below the recent June peak: Cushing, Oklahoma is the location of the largest tank farm and oil trading hub in the US. Significantly, it is the settlement point for WTI on Nymex. Crude inventories at Cushing over the past year or so have trended broadly in tandem with the wider US picture. The recent peak was in mid-June 2019 when they hit 53.6mm barrels. Subsequently, Cushing inventories have fallen and on January 17, 2020 were 34.9mm barrels, 35% below the June peak. They, however, remain well above the March 2018 low of 21.8mm barrels and should be considered normal in the context of the past ten years.

We believe declining Cushing inventories reflect new pipeline capacity in Texas which is directing more flow to the Gulf Coast in search of higher export prices.

Crude and product commercial inventories

Flat trend and comfortable level: Given fluctuations in refinery utilisation and crude oil imports and exports, the most insightful way of looking at inventories is on an all-encompassing basis, including both crude oil and refined product. On this broad definition, inventories have trended broadly flat since the third quarter of 2019. They stood at 1,294mm barrels on January 17, 2020, 6% below the recent August 2019 high of 1,374mm barrels. All-encompassing inventories currently are very comfortable from a historical perspective both absolutely and relative to supply. Currently inventories are equivalent to about 61 days' supply.

EXHIBIT 9: US COMMERCIAL OIL INVENTORIES (CRUDE AND PRODUCTS) (THOUSAND BARRELS)



Source: EIA

Gasoline inventories

Seasonally high: US gasoline inventories have been trending at or above the top end of the seasonal range in recent months. On January 17, 2020 inventories stood at 260.0mm barrels, marginally above the 259.6mm barrels of a year ago. The days' supply has trended upward pretty much in line with the seasonal tendency in recent months and on January

17 was at 30.3, modestly up from 29.8 a year earlier. The gasoline days outstanding current are at the high end of the range for the past 20 years.

Distillate inventories

Recently trended upwards to the middle of the seasonal range: After trending at the low end of the seasonal range for much of the second half of 2019, US distillate inventories have increased towards the middle of the range in recent weeks. For the week ending January 17, 2020 inventories stood at 146.0mm barrels, up 3.6mm barrels on a year ago. The distillate days' supply at 41.7 is seasonally high based on the experience over the past three years but still below the recent peak of 50 days in early 2016. The seasonally strong upward trend in distillate inventories of late reflects in large part mild weather conditions across much of the US which have depressed demand for heating oil.

Propane

Sharp seasonal fluctuations: Propane inventories fluctuate sharply seasonally reflecting its use as a fuel for space heating and drying, particularly in agriculture (crop drying is a major application). We believe significantly more than 50% of usage is fuel-related for space-heating, cooking, drying, water heating, industrial vehicles and furnaces. Significantly, sizeable quantities are also exported from the US. The bulk of propane is produced as a by-product of natural gas production. 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.

Near 25-year highs----: US propane inventories during the fourth quarter build-up were running at near 25-year highs. At the recent peak in October and November 2019 inventories hit about 101mm barrels which was similar to the highs of late 2015 and 2016. Inventories showed the normal late fourth quarter dip but remain towards the top end of the seasonal range. At January 17, 2020 they were 86.5mm barrels, up 36% from a year earlier. The days' supply for the most recent period were 59.9, well up on the 39.7 of 2019.

------reflecting buoyant production and adverse weather conditions: Seasonally high propane inventories in recent months reflect, we believe, a combination of three factors. These are buoyant natural gas production, generally mild weather in the early fourth quarter and a delayed harvest in the Upper Midwest which initially reduced drying requirements.

NET TRADE BALANCE

Net trade surplus for the first time in at least 60 years: The US swung to a net trade surplus on petroleum products, including crude oil, in the closing weeks of 2019 for the first time, we believe, in at least 60 years. The deficit peaked in late 2005 at a hefty 13.5mm b/d, remained on a high plateau over the next five years and then narrowed sharply. This was initiated firstly by a swing into surplus for refined products in 2010/11 and then a marked narrowing of the deficit on crude from 2011/12. The narrowing tendency gathered pace post 2016 and culminated in a surplus in late 2019. However, for 2019 as whole there was still a modest deficit of 0.48mm b/d. This comprised a deficit on crude of 3.82mm b/d and a surplus on refined product of 3.34mm b/d.

Compared with 2010, the deficit narrowed by 9mm b/d, undoubtedly an impressive achievement. There were a number of drivers with the key ones being as follows:

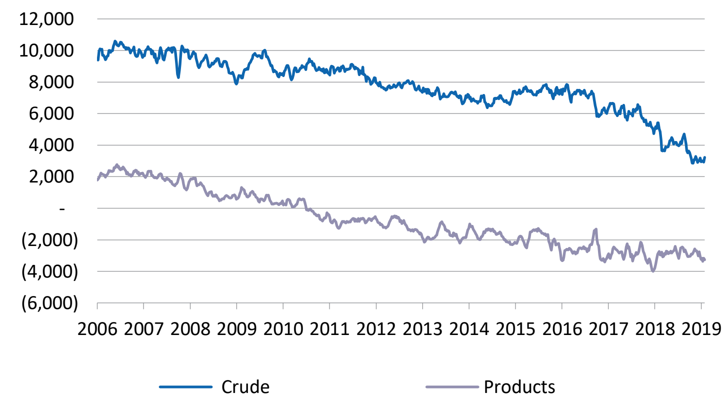
- The surge in US crude oil and NGL production which has both sharply reduced imports and since the lifting of the embargo in 2015 also boosted exports.
- The establishment of a highly competitive refinery infrastructure along the Gulf Coast.
- The ready availability to Gulf Coast refineries of cost-advantaged crude and natural gas feedstock (natural gas is also a refinery fuel).
- Strong product demand in much of the Atlantic Basin outside Europe.

- Widespread outages and sub-optimal operating performance at refineries in Latin America. Arguably two of the major positives for the US refineries have been the atrophying of the once large-scale Venezuelan refinery infrastructure and the ongoing operating problems at state-owned Pemex refineries in Mexico.
- Gulf Coast refineries are very well located to supply Latin American markets.

Crude oil deficit declining sharply as exports surge: Looking at the four-weeks to January 17, 2020 the overall trade balance came in at a surplus of 258,000 b/d against a deficit of 2.49mm b/d in the year ago period. The swing was largely attributable to a narrowing of the crude oil deficit by 2.5mm b/d to 2.9mm b/d. There was also a significant 251,000 b/d widening in the product surplus between the two periods. Exports of crude in the four-weeks to January 17 averaged a sizeable 3.61mm b/d, up 55% on a year earlier. This makes the US a major exporter even by the standards of OPEC. It should be noted that the Gulf Coast refineries to a considerable extent are configured for medium and heavy feedstock. Exports of the overwhelmingly light crude produced in Texas and the Mid-Continent therefore makes eminent sense.

Decisive swing to surplus in 2020: The EIA is forecasting a decisive swing to an overall net trade surplus in 2020 followed by a marked widening in 2021. Its forecasts call for surpluses of 0.85mm b/d and 1.40mm b/d in the former and latter years respectively. In both 2020 and 2021 the EIA continues to forecast deficits on crude but this is more than offset by surpluses on refined products.

EXHIBIT 10: US CRUDE AND PRODUCT TRADE BALANCE – (000 B/D) BARRELS PER DAY



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

DOMESTIC DEMAND

2019

Slightly weaker than expected trend in Q4: US petroleum demand was slightly weaker in the fourth quarter of 2019 than expected a few months ago. According to EIA data, demand was running at 20.64 mm b/d during the quarter resulting in 20.48mm b/d on average for 2019 as a whole. The outcome for the fourth quarter was, in fact, up 0.2% from a year ago. Previous forecasts would have suggested fourth quarter demand of about 20.7mm b/d. The adverse variance probably reflected a combination of relatively benign early winter weather conditions, the idiosyncratic factors surrounding propane usage mentioned above and softening activity in the oil patch and possibly agriculture. Note here, the oil patch is a major user of diesel for drilling, fracking, power generation and transportation.

Demand marginally down for the year but remained at a historically high level: Based on EIA data, petroleum demand in 2019 was marginally under the previous year's 20.50mm b/d. The largest product lines gasoline (9.28mm b/d), distillates (4.06mm b/d), NGLs

(3.16mm b/d) and jet fuel (1.75mm b/d) showed year-on-year movements as follows: -0.5%, -2.2%, +5.0% and +2.3% respectively. On the same basis fuel oil declined 9.4% while the miscellaneous category showed a drop of 4.0%. Note, that NGL demand in the US has been driven by new ethylene cracking capacity coming on-stream. In the case of gasoline, a favourable economic backdrop, a benign trend in commodity prices and rising vehicle miles travelled (+1.1% based on EIA data) seems to have been offset by rising fuel efficiency.

2020

Soft trend in early 2020: US petroleum demand has been soft early in 2020. Based on EIA, data for the four weeks ending January 17, demand averaged 19.96mm b/d, down 1.6% on a year earlier. In terms of product lines gasoline, distillates, fuel oil and propane were off year-on-year by 1.4%, 8.3%, 2.7% and 10.1% respectively. Against this, demand was up year-on-year by 3.8% for jet fuel and 5.1% for a large miscellaneous category which includes NGL's other than propane.

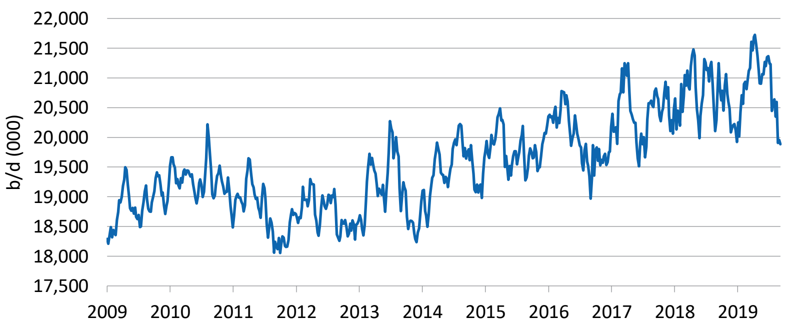
Modest growth forecast by EIA in 2020----The EIA continues to forecast modest petroleum demand growth in 2020. Its forecast calls for a gain of 0.8% to 20.64mm b/d, just short of the 2005 all-time high of 20.76mm b/d. The forecast is based on GDP growth of 2.0% and an average retail gasoline price (all grades) of $2.75/gallon, up 2.2% on 2019. Again, as for earlier forecasts, the key factor supporting demand in 2020 is likely to be NGLs related to increasing ethylene cracking capacity. Growth of 5.4% is forecast by the EIA for this product line. Elsewhere, the EIA is looking for marginal gains in demand for gasoline, distillates and jet fuel in 2020 and dips in fuel oil and the miscellaneous category of 10% and 1% respectively.

2021

------and 2021 taking demand to record levels: Marginal US petroleum demand growth of 0.3% is forecast by the EIA for 2021. This would take demand to 20.71mm b/d. Once again, the key area of strength is likely to be NGLs. According to the EIA, demand for distillates, jet fuel and miscellaneous will be essentially flat while gasoline could be down by 0.6% to 9.23mmb/d driven by rising auto fuel efficiency.

The EIA's 2021 forecast reflects the assumptions of 1.8% GDP growth and an average retail gasoline price of $2.76/gallon. We believe the EIA's petroleum demand growth forecasts look plausible based on the assumptions given. However, we note that the EIA's GDP growth assumptions for 2020/21 are towards the high end of the consensus range. A lower forecast of 1.5% would have a perceptible impact on petroleum demand, particularly in terms of those sectors exposed to industrial activity. We believe that GDP growth of sub 1.5% would probably lead to a decline in petroleum demand.

EXHIBIT 11: US PETROLEUM PRODUCT SUPPLIED (B/D '000)



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

SUPPLY-DEMAND BALANCE

2019

Marginal deficit in 2019: Globally the petroleum market was in marginal deficit in 2019. According to the EIA, this was 0.02mm b/d so for practical purposes we were looking at an approximately balanced market. This contrasts with a significant surplus of 0.92mm b/d in 2018. Following the hefty supply surplus of 2.2mm b/d in the fourth quarter of 2018, a marked narrowing took place in the first half of 2019. The surplus during this period averaged 0.39mm b/d. During the third quarter there was a major swing to a sizeable deficit 0.98mm b/d. This was followed by a return to surplus in the fourth quarter, albeit a modest one of 0.13mm b/d.

The key factors tightening the market were as follows:

- The OPEC+production accord agreed at the end of November 2018.
- US sanctions on Iran and Venezuela.
- The atrophying of the Venezuelan production infrastructure.
- The September 14 attack on the Saudi Aramco facilities at Abqaiq and Khurais.

The sharp decline in OPEC crude production was more than sufficient to offset non-OPEC output growth. Consumption growth at 0.82mm b/d was weaker than generally expected at the beginning of 2019 reflecting a lacklustre macro-economic backdrop in both the OECD and non-OECD worlds. Nevertheless, the production dynamics, arguably slightly fortuitously, tightened sufficiently to bring about approximate balance in the marketplace.

2020

For 2020 and 2021 we have used as a base the EIA's January 2020 forecasts for the petroleum market supply-demand balance. We believe they looked plausible against the likely macro-economic and petroleum industry backdrop prior to the onset of the coronavirus epidemic in China.

In 2020 the petroleum market is likely to share with 2019 the characteristic of buoyant non-OPEC production growth. OPEC production, however, is expected to be lower than in 2019 due to the need to implement cutbacks to offset the coronavirus induced decline in demand. Overall, because of the hit to China demand global oil consumption is likely to be significantly weaker in 2020 than most forecasters were expecting just a few weeks ago.

Non-OPEC production

Strong non-OPEC output growth likely driven by the US-----The EIA is looking for non-OPEC oil output growth in 2020 of 2.6mm b/d or 4.0% to 68.1mm b/d. This will be one of the larger gains in recent years and only exceeded in absolute terms by the 2.8mm b/d increase in 2018. Based on the EIA forecast, non-OPEC output will represent 66.6% of the global total of 102.4mm b/d. This is up from 65.1% in 2019.

-------Brazil, Canada, Norway and Guyana: The key drivers behind non-OPEC output growth in 2020 are likely to be the US, Brazil, Canada, Norway and the new oil province, offshore Guyana. Once again, the US will probably be the largest contributor with growth of perhaps 1.7mm b/d including NGLs, renewables and refinery gain. The contributions by the other four sources based on EIA data could be Brazil 0.4mm b/d, Canada 0.2mm b/d, Norway 0.4mm b/d and Guyana 0.1mm b/d. As has been the case for several years, the key area of weakness in 2020 is likely to be Mexico where output could be down 0.2mm b/d reflecting a continuing high rate of depletion.

Rising capacity utilisation and new development projects in the Santos pre-salt Basin: In the case of Brazil higher production in 2020 reflects a combination of rising capacity utilisation at recently installed FPSO's (floating, production, storage and offloading vessels) and new development projects in the prolific pre-salt Santos Basin, offshore Rio de Janeiro and Santos. Seven new FPSO's have been installed over the past two years and have now reached full capacity. A further one or two FPSOs could commence operations in 2020. Gains in the Santos Basin will be partly offset by high rates of depletion in the mature Campos Basin.

Reversal of the Alberta 2019 production curtailments: Canadian production in 2020 should increase driven by higher utilisation in the Alberta oil sands operations, assuming a non-recurrence of the inventory build-up and the provincial government production curtailments of late 2018 and early 2019. Much here will depend on the economics of rail transportation from Alberta to the US Gulf Coast. As of late January, the economics were looking conducive to stepping up shipments given the wide WTI-WCS price spread.

Commissioning of the giant Johan Sverdrup field: Norwegian production is currently being given a major boost following the commissioning in October 2019 of phase 1 of Equinor's giant Johan Sverdrup oilfield, the third largest discovery on the Norwegian Continental Shelf. Significantly, the production build-up has been going very much to schedule with 0.20mm b/d achieved within three weeks of start-up and 0.35mm b/d in December. Full capacity working of 0.44mm b/d is planned for the third quarter of 2020. Production capacity is expected by Equinor to be expanded in Phase 2 to 0.66mm b/d by end 2022.

Start-up of ExxonMobil's offshore Guyana operations: ExxonMobil commenced production using a FPSO at the Liza field in the Stabroek Block, offshore Guyana, in December 2019. In the coming months production is expected by the company to rise to the planned Phase 1 capacity of 0.12mm b/d. ExxonMobil anticipates that as five or more FPSO's come on-stream production from the Stabroek Block will rise to more than 0.75mm b/d by 2025.

OPEC production

Continuing subdued trend in 2019: OPEC crude oil production is likely to remain on a subdued trend in 2020. The key factor here is the OPEC+ production accord of early December 2019. This called for an increase in the target cutback from an October 2018 base from 1.2mm b/d to 1.7mm b/d. The accord remains effective through end March 2020 but seems likely to be extended in the absence of a major supply shock. Compliance with the accord overall has been tight not least because of production being under pressure at sanctions hit Iran and Venezuela and the aggressive line taken by Saudi Arabia to curb production.

Bearing in mind the above factors, the EIA is looking for a decline in OPEC crude production in 2020 of 0.6mm b/d. It should also be noted that because of the US sanctions on Iran that there is a significant drop in OPEC NGL output in 2020 of 0.37mm b/d. Assuming that further cutbacks are agreed in the wake of plunging demand in China, OPEC+ production will probably fall by more than 0.6mm b/d in 2020.

Global Consumption

Another year of robust growth driven by non-OECD markets: The EIA's January 2020 forecasts before the onset of the coronavirus epidemic called for growth in global oil consumption of 1.34mm b/d or 1.3% in 2020. As has been the case for many years, growth was expected to be driven by the non-OECD world. Here, a gain of 1.21mm b/d or 2.3% was forecast against 0.13mm b/d or 0.3% in the OECD. In terms of the non-OECD world, the key contributors to consumption growth in 2020 were China and India with gains of 0.5mm b/d and 0.2mm b/d respectively. OECD consumption was driven by the US with a gain of 0.16mm b/d. Modest declines were forecast for Europe and Japan.

Faster GDP growth, large petrochemical plants coming on-stream, IMO sulphur content rules: The EIA's January forecast for global consumption growth in 2020 significantly exceeded the 0.82mm b/d gain for 2019. This reflected three factors. Firstly, an assumed acceleration in GDP growth from 2.2% to 2.4% (oil weighted) using the EIA model. Secondly, the allowance in 2020 for some very large petrochemical plants coming on-stream in the US, China and Russia all using NGL's as feedstock. Thirdly an expectation that the new IMO rules concerning the sulphur content for marine fuel will boost volume by about 0.1mm b/d due to the greater use of lower energy density distillates.

Clearly, the fast-moving situation in China regarding the coronavirus epidemic implies a significant downgrade to the EIA's January 2020 global demand forecast. Since the onset of the epidemic in mid-January, we believe China oil demand could be down year-on-year by over 2mm b/d or 15%. A recent article carried by Bloomberg and based on industry sources suggested, in fact, that demand in early February 2020 was down year-on-year by a hefty 3mm b/d or over 20%. While this is possibly an exaggeration for 2020 as a whole, demand is likely to be significantly lower than in 2019 even assuming a recovery in the second half of the year.

Our forecast for 2020 calls for a year-on-year drop of 0.7mm b/d. Using the EIA January forecast as a base this would imply a reduction in global demand growth of a similar amount to 0.64mm b/d. Arguably we should also include some second order effects of the crisis in China due to the adverse impact on economic activity elsewhere in the world. We discuss the impact of the coronavirus epidemic in China in greater detail in the section entitled Wild Cards and Commodity Price Risk.

Supply-demand balance

Modest supply surplus in 2020: In its January 2020 report the EIA forecast a modest supply surplus of 0.26mm b/d. This is similar to that given in our October 2019 O&G Macro Outlook. The EIA's scenario called for a surplus through the first three quarters partly offset by a deficit in the fourth quarter. In the light of developments in China in recent weeks the EIA's January forecast now looks obsolete unless some sizeable production cutbacks can be implemented by OPEC+.

If we add our forecast of the coronavirus demand impact to the EIA's January forecast the result would be a surplus of about 1mm b/d before allowing for any second order effects of the coronavirus epidemic globally and potential production cutbacks. While not unprecedented, such a surplus would be one of the largest over the last ten years. Given the uncertainty surrounding the scale and duration of the coronavirus epidemic, we believe the risks are to the upside concerning the potential scale of the surplus in 2020.

2021

Tightening market with a swing to deficit: The EIA's January 2021 scenario called for a significant tightening in the petroleum market in 2021. A deficit of 0.15mm b/d was forecast. The tightening reflected a continuation of the buoyant consumption trend of 2020, a sharp drop in non-OPEC production growth and continuing production restraint by OPEC. Specifically, the forecast for 2021 reflects the following year-on-year movements:

- Global demand growth +1.38mm b/d
- Non-OPEC output growth +0.88mm b/d
- OPEC crude oil production +0.09mm b/d
- OPEC NGL production unchanged

Much lower non-OPEC output growth: The increase in global demand was predicated on GDP growth (oil weighted) of 3.0% which was significantly above the previous year and a strong showing by the standards of recent years. Arguably, this could have been viewed as unduly bullish given the less than robust backdrop to the world economy and the potentially depressing influence of climate change policy.

A major issue now concerning the demand outlook in 2021 is just how quickly China emerges from the coronavirus epidemic. Assuming the dissipation of the crisis by the end of the third quarter of 2020 it is conceivable that demand growth in 2021 exceeds the EIA's January forecast. The key question would then be the speed of response by OPEC in boosting output.

The EIA's January forecast of a pronounced deceleration in non-OPEC output growth in 2021 was driven by the US and stems from the lagged impact of lower development activity in the tight reservoir basins of Texas and the Great Plains. Based on the EIA forecast US production growth slows from 1.71mm b/d in 2020 to 0.61mm b/d in 2021.

EXHIBIT 12: GLOBAL OIL SUPPLY/DEMAND BALANCE

Mm b/d	2015	2016	2017	2018	2019	2020e	2021e
Global consumption	95.64	96.75	98.73	99.95	100.77	102.11	103.49
Non-OPEC oil production	60.69	60.12	60.75	63.55	65.54	68.13	69.01
OPEC NGL production	**5.19**	**5.25**	**5.30**	**5.36**	**5.42**	**5.05**	**5.05**
OPEC crude call	29.76	31.38	32.68	31.04	29.81	28.93	29.43
OPEC crude production	31.22	32.21	32.07	31.96	29.79	29.19	29.28
Surplus/(deficit)	**1.46**	**0.83**	**-0.61**	**0.92**	**-0.02**	**0.26**	**-0.15**
Global production	97.10	97.58	98.12	100.87	100.75	102.37	103.34
Non-OPEC share of global production %	62.5	61.6	61.9	63.0	65.1	66.6	66.8
YOY changes %							
Global consumption	2.2	1.2	2.0	1.2	0.8	1.3	1.3
Non-OPEC crude production	2.7	-0.9	1.0	4.6	3.1	4.0	1.3
OPEC crude production	4.1	3.2	-0.4	-0.3	-6.8	-2.0	0.3
Global oil production	3.0	0.5	0.6	2.8	-0.1	1.6	0.9
YOY changes mmb/d							
Global consumption	2.07	1.11	1.98	1.22	0.82	1.34	1.38
Non-OPEC crude production	1.57	-0.57	0.63	2.80	1.99	2.59	0.88
OPEC crude production	1.24	0.99	-0.14	-0.11	-2.17	-0.60	0.09
OPEC NGL production	0.01	0.06	0.05	0.06	0.06	-0.37	0.00
Global oil production	2.82	0.48	0.54	2.75	-0.12	1.62	0.97
World GDP growth (oil weighted) %	2.9	2.8	3.2	2.9	1.9	2.4	3.0
US GDP growth (2012 dollars) %	2.9	1.6	2.4	2.9	2.3	2.0	1.8

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

CRUDE OIL PRICE OUTLOOK

MARKET THESIS

2020

Greater than expected carryover strength entering 2020: The trend in benchmark light crude prices was stronger than we expected in late 2019. This reflected growing tension in the Middle East between the US and Iran, the reinforced OPEC+production accord struck in early December and the emergence of a truce in the US-China trade war. At the end of December 2019, Brent and WTI were trading at $66.0/barrel and $61.1/barrel respectively which implied significantly greater carryover strength entering 2020 than implied by our October forecast. Prices were given a further boost in the early days of January 2020 following the assassination of the powerful Iranian General, Qassem Soleimani on the 2nd of the month. On January 6 prices hit recent highs of $70.3/barrel for Brent and $63.3/barrel for WTI.

Soleimani assassination quickly forgotten: By end-January, however, the Soleimani assassination was apparently forgotten with Brent down to $58.2/barrel and WTI to $51.6/barrel. Initially, prices were driven south by an absence of a serious escalation in hostilities between the US and Iran and by the realisation that the market was well supplied for the moment in the absence of supply shocks.

Coronavirus outbreak in China added to bearish views: Bearish views in late January 2020 were given added potency by the coronavirus outbreak in the Chinese conurbation of Wuhan (population 11m), Hubei province (population 60m), 800 km west of Shanghai. Prior to the coronavirus outbreak, we were expecting oil prices to be supported near-term by simmering US-Iran tension and military conflict in Libya. Significantly, over the past week or so Libyan output has been cut by about 0.8mm b/d following the closure of the country's major export terminals by the forces of General Haftar, the leader of the Libyan National Army in Benghazi.

We are assuming that the epidemic is steadily brought under control over the next three-six months: The near-term oil price outlook is now obviously contingent on the international extent and intensity of the coronavirus epidemic. Clearly, it has already heavily impacted demand in China given the size of both Wuhan and Hubei province, the importance of the former as a transportation hub and industrial centre, official anti-contagion measures and the second order effects elsewhere in the country.

For the purpose of the price forecasts we are assuming that the coronavirus is steadily brought under control in Hubei over the next three to six months. Inevitably even this relatively benign outcome implies a significant loss of demand in China and a looser supply/demand outlook internationally during the first half of 2020 than might otherwise have been expected. Our thinking concerning the potential loss of demand due to the coronavirus epidemic is discussed in greater detail under Wild Cards and Commodity Price Risk.

Brent averaged $63.7/barrel in January 2020 but ended the month at $58.2/barrel. Reflecting carryover weakness, further heavy downward pressure in the early days of February and a possible intensification of the coronavirus crisis near-term we look for Brent averaging $53.0/barrel in February and March 2020. This would imply an average for the first quarter of $56.6/barrel which compares with our immediately pre-coronavirus forecast of $66.0/barrel.

It should be noted that although we are assuming the crisis persists in the coming months in China, our thinking is that the epidemic does not veer out of control or spreads in a significant way to other countries. We also believe the OPEC+consortium will implement production cutbacks in the coming weeks to at least partially offset slumping demand. Subject to these assumptions and clear signs that the epidemic is stabilising post the first quarter, we would expect to see oil prices firm modestly over the balance of the year. We look for Brent averaging $54.0/barrel in Q2, $56.0/barrel in Q3 and $58.0/barrel in Q4. The implied average for 2020 of $56.2/barrel is down 13% on 2019. Our WTI forecast for 2020 calls for an average of $51.8/barrel, a discount of $4.4/barrel to Brent. This reflects a sharp narrowing in the WTI discount from $7.4/barrel in 2019. The narrowing stems from two influences. Firstly, the impact of upgraded pipeline connections between Cushing and the Gulf Coast and especially the Permian Basin and the Gulf Coast which has led to cuts in pipeline tariffs. The second factor concerns the relative insulation of WTI to international influences. Brent, the international benchmark, is arguably more sensitive to the slump in Chinese demand than WTI. The forecast discount compares with pipeline tariffs from Cushing to the Gulf Coast of about $2.25/barrel.

Significantly downgraded 2020 forecasts for the coronavirus epidemic: Our new 2020 forecasts for Brent and WTI reflect downgrades from those given in our November 2019 report of $61.5/barrel and $56.3/barrel respectively. The downgrades relate to the coronavirus epidemic driven plunge in commodity prices of late and the expectation that this factor will remain a depressing influence at least into the third quarter. Our new 2020 forecasts for Brent and WTI are about $10/barrel lower than contemplated before the onset of the coronavirus epidemic in mid-January.

2021

Firming price trend reflecting tightening market: We see scope for a firming trend in light crude benchmark prices in 2021. The key positives are potentially a return to the semblance of normality in the Chinese economy and the anticipated underlying tightening in the petroleum market globally. Geo-political issues may also buoy prices. We see Brent trending upwards from around $**59.0**/barrel in the first quarter to $6**6**.0/barrel in the fourth quarter. For **WTI** we see an upward trend from $5**4.5**/barrel to $6**1**.0/barrel. The averages for 2021 are $6**3.3**/barrel for Brent and $**58.6**/barrel for WTI.

The WTI discount for 2021of $4.6/barrel is similar to our forecast for the previous year.

WILD CARDS AND COMMODITY PRICE RISK

Petroleum, in common with other commodity markets, is subject to a wide range of wild cards and areas of uncertainty. The key issue for the petroleum market as for other commodities near to medium-term is unquestionably the coronavirus epidemic. There are however other matters of interest including, macro-economic developments, shale well productivity, 2020 US presidential election, Middle East geopolitical tension, Venezuela and the OPEC+production accord. We could also add climate change issues and the associated political hysteria. In our December report we visited climate change issues and presented our longer-term thoughts on how oil production might develop. We will return to this subject in the future. Meanwhile our thoughts on the near to medium-term wild cards and risks are given below.

Coronavirus:

Preoccupation of commodity markets currently: The coronavirus epidemic in China has become the overwhelming near-term preoccupation of financial and commodity markets, including petroleum. Market concerns relate to the potentially depressing effect on GDP and hence oil consumption in the world's second largest economy and petroleum market. In an attempt to contain the epidemic official measures to restrict movement combined with voluntary curbs on even short-distance travel will inevitably weigh on consumer and business spending on goods and services. Transportation is especially vulnerable. Industrial production will also be directly impacted due either to enforced closures or disrupted transportation. Outside China aviation fuel usage looks like being an early casualty of the coronavirus epidemic.

Wuhan, Hubei province in east-central China is the epicentre: The epicentre of the epidemic is Wuhan, Hubei province about 800 km west of Shanghai. With a population of around 11m Wuhan is one of the ten or so largest cities in China and is a major industrial centre and transportation hub. Hubei has a population of approximately 60m and is about the same size as the UK but accounts for only about 4% of the Chinese total. The key question now concerns the potential severity and duration of the coronavirus epidemic. Inevitably there is massive uncertainty over this question, but we can possibly gain insights from the SARS (SARS is also a coronavirus) epidemic in China in 2002/3. This lasted roughly nine months between November 2002 and July 2003 and involved 8,273 cases and 775 deaths of which 88% were in greater China, according the World Health Organisation. As of end January 2020, there were almost 10,000 coronavirus cases officially reported in China resulting in 213 deaths, according to the BBC.

Our estimate of the oil market in east-central China is mm b/d: The starting point for assessing the potential impact of the coronavirus on oil consumption is our estimate of the scale of the east-central China market based on Hubei and the surrounding provinces. In 2019 we believe this could have been about 3.9mm b/d based on a total China market of 14mm b/d and a pro-rate to population.

We have assumed that the market in Hubei and surrounding provinces could initially be halved-----: Heroically we have assumed that oil consumption in the first quarter of 2020 could be halved in Hubei and cut by 25% in the surrounding provinces. This would imply a decline of 1.1mm b/d year-on-year. In addition, for the rest of China we have allowed for a 10% year-on-year decline which would take the national impact to 2.1mm b/d or about 15% since the start of the coronavirus epidemic. Recent reports on Bloomberg suggest, in fact, that in early February Chinese petroleum demand was down year-on-year a hefty 3mm b/d or 21%.

EXHIBIT 13: CHINA CORONAVIRUS IMPACT

Province	Population m	China Weighting	Est 2019 oil consumption mm b/d	China 2020 coronavirus impact mmb/d Q1	Q2	Q3	Q4	Average
East-central China								
Anhui	62	4.3	0.61	-0.15				
Chongqing	30	2.1	0.29	-0.07				
Henan	95	6.7	0.93	-0.23				
Hunan	67	4.7	0.66	-0.16				
Hubei	59	4.1	0.58	-0.29				
Jiangxi	45	3.2	0.44	-0.11				
Shaanxi	37	2.6	0.36	-0.09				
Total	**395**	**27.7**	**3.87**	**-1.11**				
RO China	1033	72.3	10.13	-1.01				
Total China	**1428**	**100.0**	**14.00**	**-2.13**	**-1.06**	**-0.53**	**0.98**	**-0.68**

Assumptions: 2019 oil consumption is pro-rata to population, Q1 oil consumption impact reflects a 50% drop in Hubei and declines of 25% elsewhere in east-central China and 10% in the rest of China. Q4 impact reflects a 7% YOY increase in demand.

Source: Wikipedia, EIA and Allenby Capital

-------but impact should lessen as the year progresses: Assuming traction is gained in tackling the epidemic, we would expect oil consumption to steadily recover on a sequential basis in the second and third quarters of 2020. Year-on-year, however, we think we could still be looking at significant declines. Our scenario calls for year-on-year declines of about 1.1mm b/d and 0.5mm b/d in the second and third quarters of 2020 respectively. In the fourth quarter a significant recovery is possible assuming that the back is broken of the epidemic and the economy regains upward momentum. We have assumed a 7% gain implying an approximate 1mm b/d boost in absolute terms.

Lower demand will probably be partially offset by OPEC+production cutbacks: Based on the above scenario the impact of the coronavirus epidemic in China during 2020 would be about 0.7mm b/d on average. Such a decline, other things be equal, would widen the previously anticipated global supply surplus from 0.26mm b/d to almost 1mm/bd. While this is certainly not without significance, it is far from being unprecedented. Furthermore, we think it likely that lower demand would be at least partially offset by OPEC+consortium production cutbacks.

Macro-economics:

Macro-economic backdrop is fragile: Recessionary concerns regarding 2020/21 receded prior to the coronavirus outbreak but as the IMF noted in its January Economic Outlook the global macro-economic backdrop is fragile. Reflecting this, the IMF's GDP growth forecasts have recently been downgraded from 3.4% to 3.3% for 2020 and 3.6% to 3.4% for 2021. The forecasts, however, reflect a significant acceleration from the 2.9% of 2019 with the implementation of more aggressive monetary policy by several OECD countries arguably being the key driver.

Several major areas of concern including the coronavirus epidemic: In the wake of the coronavirus outbreak in January, earlier GDP forecasts made by the IMF and other international bodies will need downgrading and possibly sharply. Note here that we are not just looking at the direct impact of the coronavirus epidemic on China but all the second order effects internationally. Transportation and tourism readily spring to mind along with the impact on commodity producers and exporters of manufactures. Clearly, there is considerable uncertainty regarding the duration of the coronavirus epidemic which will have a bearing on global GDP forecasts not just for 2020 but also 2021.

Downgraded GDP forecasts will translate into cuts in petroleum demand for 2020 and possibly 2021 made by the likes of the EIA, IEA and OPEC. Particularly for the former year the cuts are likely to be sizeable. Lower demand forecasts will in turn flow through to the supply/demand balance. A looser supply/demand relationship than envisaged until recently ,at least potentially has negative implications for commodity prices. In the case of petroleum, however, we note that light crude prices have fallen over 20% from the early January highs and are already discounting a challenging backdrop. Arguably, the key factor now from a price perspective concerns the duration of the epidemic. Does it more or less follow the pattern of SARS or are we looking at an extended epidemic possibly extending into 2021. The latter certainly has not been discounted.

Middle East tension:

Geopolitical tension in the Middle East boiled over in two extreme forms in recent months. These were the devasting Iranian attack on Saudi oil facilities at Abqaiq and Khurais and the US assassination of the Iranian Revolutionary Guard commander General Soleimani. The Iranian response to the latter was muted and overshadowed by the downing of a Ukraine airliner. We can't, however, assume that this is the end of the matter.

Iran may seek revenge for the Soleimani assassination: Iran may well seek revenge at a moment of its choosing. Although President Trump has expressed a desire to withdraw from entanglement in the Middle East, we suspect that he would have to respond militarily in such circumstances. The result could be serious damage to infrastructure on both sides of the Persian Gulf including oil and gas facilities and at least for a time the interruption of shipments of oil and LNG through the Straits of Hormuz. Bearing in mind that approximately 25% of the world's oil passes through the Straits prices would probably climb above $100/barrel very quickly.

Libya and General Haftar:

General Haftar steps-up the pressure on the UN recognised Tripoli government Since the overthrow of long-time dictator Colonel Gaddafi in 2011, Libya has been subject to intensive factional fighting, turf wars and outright warfare supported by external powers. The latest round of fighting involves General Khalifa Haftar the commander of the Libyan National Army based in Benghazi in the east of the country and the UN recognised government in Tripoli in the west led by Prime Minister, Fayez al-Sarraj. Significantly, General Haftar controls the bulk of Libya's oilfields plus the export terminals in the east and has been successful in pacifying most of the country. He also has some powerful friends in the form of Egypt, UAE, Saudi Arabia, Russia and maybe France. General Haftar does not, however, control the receipts from oil exports. These are handled by the Tripoli government. Its key patron is Turkey. The US appears to have changed sides of late from supporting General Haftar to the Tripoli government.

In a move to take complete control of Libya General Haftar launched the proverbial big-push on Tripoli last autumn. A stalemate has subsequently ensued. How this will ultimately be resolved is unclear. One possibility is that General Haftar is ultimately victorious. The problem would then be how oil production is monetised since his government would probably not be internationally recognised. The alternative solution would seem to be a power sharing agreement with oil revenues split equitably between east and west.

--------by cutting supply to export terminals thereby tightening availability of light oil in the Mediterranean: Thanks to the success of General Haftar's pacification programme, Libyan oil production has run at what many independent observers consider a surprisingly high level. Production has in fact recently been running at 1.3-1.4mm b/d which is approaching the level of around 1.6mm b/d prior to the overthrow of the Colonel Gaddafi. In support of his bargaining position General Haftar cut supplies of oil to the western terminals a few weeks ago. According to press reports this has lowered production to about 0.2mm b/d. A further decline to under 0.1mm b/d is a distinct possibility. If this cutback is sustained, it will quickly tighten the supply of high-grade light oil in the Mediterranean basin.

Any resolution to the conflict could, however, rapidly boost the availability of light firstly back to 1.4mm b/d and probably with a short lag to 1.6mm b/d. Libya in theory has the reserves to produce considerably more than 1.6mm b/d but this may require significant investment.

US tight reservoir production:

Uncertainty surrounds the pace at which tight reservoir production growth slows: We believe one of the most influential indicators for oil prices in 2020/21 will be the trend in US tight reservoir production. The exceptionally rapid rate of growth in US production particularly over the past five years has been a revolutionary development which has severely undermined the power of OPEC to manage the oil market. Given declining development activity and well productivity in some US zones, the key issue now is just how quickly production growth slows. A more rapid slowdown than generally expected, particularly in the Permian, could quickly be reflected in firming prices.

US Presidential election

The leading Democrat contenders are all hostile to oil and gas: The key issue here concerns the Democrat party contenders. The three leading nominees Bernie Sanders, Elizabeth Warren and Joe Bidden are all hostile to the oil and gas industry. The latest entrant in the race for the nomination, Michael Bloomberg, is also no friend of the oil and gas patch. If any of these four wins the Presidency in November and have the requisite support in Congress, the very existence of the oil and gas industry will be threatened. In broad terms a two-pronged attack is proposed. This involves firstly tightening legislation on emissions and other criteria which would boost costs both in the primary production and consumption of hydrocarbon fuel, thereby reducing industry viability. Secondly, banning drilling on Federal land and having an outright prohibition on fracking across all jurisdictions. Tax changes will also be implemented to eliminate what are alleged to be petroleum industry subsidies.

Potential to unwind the shale revolution: Implementation of a programme as outlined would result in a rapid unwinding of the shale oil and gas revolution of the past ten years or so. Consumers would also quickly notice a surge in their bills for gasoline, diesel, electricity, heating oil, air-fares and a whole host of other items.

Venezuela:

Surprisingly President Maduro has clung to power: One of the great surprises of 2019 was the ability of President Nicholas Maduro to maintain power in Venezuela despite economic collapse, a stratospheric rate of inflation, US financial and trade sanctions, civil unrest, attempted coups, a population exodus and plunging oil production. President Maduro is, indeed, the great survivor. The explanation to his continuing survival is principally the continuing support of the army, China and particularly Russia. We should also credit President Maduro with having guile. In addition, President Maduro has been able to generate cash from domestically produced gold and quite possibly drugs. These peripheral sources of cash are important given that export revenue from oil is mainly pre-empted for debt repayment to China and Russia.

President Maduro's position increasingly precarious: Significantly, President Maduro has recently been putting out peace feelers via the Washington Post to the US. Furthermore, Venezuela's cash reserves are now said to be distinctly marginal at about a billion dollars. Clearly, President Maduro's predicament is precarious and becoming steadily more so. It would probably become critical if he has difficulty in maintaining the purchasing power of the police and army in dollars. The upshot is that regime change by one means or another becomes increasingly likely.

As we have noticed previously, any incoming regime would want to quickly restore the production of crude and refined products. While crude production could not be boosted instantaneously from the current level of about 1mm b/d to the levels of over 3mm b/d before Hugo Chavez came to power in 1999, it might be possible to raise output to 2mm b/d within a year or so assuming access to international oilfield services expertise. This would, of course, be a not insignificant event in terms of the world supply-demand balance for oil. The price implications for heavy grades, the mainstay of Venezuelan production, would potentially be particularly negative.

OPEC+production accord:

OPEC meeting scheduled for March 20----OPEC and a group of allies led by Russia have been implementing a policy of production restraint since January 2017. The current programme agreed in early December 2019 and aimed at keeping output 1.7mm b/d below October 2018 levels is scheduled to run until end March 2020. Outside the accord several countries most notably Saudi Arabia agreed to make further voluntary cuts taking the total to 2.1mm b/d.

------but this could be pulled forward and lead to new production cuts: In the wake of the coronavirus epidemic and the recent heavy downward pressure on oil prices the scheduled March OPEC meeting looks like being pulled forward. At base, the terms of the accord seem likely to be extended to end 2020. There is, however, a very real possibility that further production cuts will be implemented to offset the adverse demand implications of the coronavirus epidemic. Failure to agree new cuts could well exert additional downward pressure on prices. In the event of an intensification of the epidemic and no agreement on further cuts, Brent and WTI could test $45/barrel and $40/barrel.

There are schisms among the OPEC+ consortium members but we don't expect these to prevent a new accord such is the market malaise post the advent of the coronavirus outbreak. Doubtless the schisms will resurface once the epidemic subsides. One of the big unknowns longer term is whether President Putin wants Russia to be the de-facto leader of OPEC.

EXHIBIT 14: BRENT 2009-2020 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	56.6	54.0	56.0	58.0	56.2
2021e	59.0	63.0	65.0	66.0	63.3

Source: EIA and Allenby Capital

EXHIBIT 15: WTI 2009-2020 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	52.6	49.5	51.5	53.5	51.8
2021e	54.5	58.5	60.5	61.0	58.6

Source: EIA and Allenby Capital

EXHIBIT 16: BRENT AND WTI PRICE LONG-TERM TRENDS

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020e	2021e
110	112	108.8	99.1	52.4	43.7	54.3	71.2	64.4	56.2	63.3
94.9	94.2	98	93.2	48.7	43.2	50.9	65.1	57.0	51.8	58.6

Source: EIA and Allenby Capital

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