NATURAL RESOURCES

April 2021

OIL & GAS

OIL & GAS MACRO OUTLOOK

Bullish near-term outlook but potential supply influx

Benchmark light crude prices surged in late 2020 and Q1 2021 driven by positive sentiment surrounding the roll-out of corona virus vaccines and a marked tightening in the market. The tightening reflects both recovering demand and constrained supply stemming from the deep cuts in production orchestrated by the Saudi led OPEC+ alliance. With Brent trading at around $65/barrel light, crude benchmarks are once again at comfortably profitable levels for the bulk of producers. Over the balance of 2021 we expect a narrowing in the supply deficit. Demand should increase powerfully in the coming months courtesy of a strengthening world economy but we believe this will be outpaced by production. The key driver will probably be the OPEC+ alliance following an agreement to partially reverse earlier cutbacks. We expect a bullish economic backdrop to boost prices through early 2022 with Brent probably exceeding $70/barrel. In our view, the upswing in prices will succumb during H2 2022 to an influx of supply particularly from OPEC. Demand should remain buoyant throughout our forecast period to 2023.

- **Supply/demand balance**: The EIA estimates that the oil market globally was in deficit to the tune of a hefty 2.51mm b/d and 2.07mm b/d in Q4 2020 and Q1 2021, respectively. Over the balance of 2021, the EIA is looking for sharply narrowing deficits as production gathers pace. A sizeable deficit of 0.99mm b/d is nevertheless forecast for 2021. The EIA is calling for a narrowing in the deficit to 0.20mm b/d in 2022 and we look for approximate market balance in 2023.

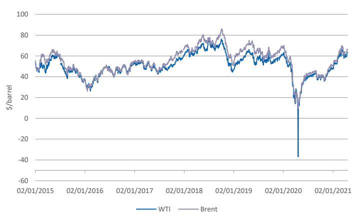
- **Oil production:** After falling by 6.4% in 2020 global oil production looks like increasing by about 2.5%, based on EIA data. Non-OPEC production will probably be up by around 2% while OPEC gains nearer 4%. The increase in the former is mainly driven by Brazil, Canada, Norway, and Russia. Gains in Brazil and Norway reflect field development activity while Canada and Russia should benefit from the restoration of cutbacks in 2020. The growth in OPEC in 2021 stems from the roll back of cutbacks in 2020 and a return to more normal levels of production in Libya following civil war-induced disruptions for much of 2020.

- **Oil demand**: Following a sizeable drop in 2020 of about 9%, oil demand global is likely to make a strong recovery in 2021 reflecting a rapidly strengthening world economy and some easing of covid-related restrictions on mobility. The EIA is forecasting a growth in global oil demand in 2021 of 6.0% with similar gains for the OECD and non-OECD worlds. Further growth of 3.7% is expected by the EIA for 2022 while we look for a gain of 3.3% in 2023. The latter would imply global demand of 104.7mm b/d, a record and significantly above 2019's 101.2mm b/d. Near-term, we see the chief demand forecast vulnerabilities as being a new wave of corona virus particularly in the US and a potential surge in US 10-year Treasury yields to 2% plus by end 2021.

- **President Biden and oil**: So far, President Biden has been true to his word on petroleum industry matters. He has banned new drilling on federal land, cancelled the Keystone XL pipeline and proposed changes in the accounting tax code to disadvantage oil and gas companies. Further measures are under consideration which will raise costs and could roll back the shale revolution. The President's infrastructural plan will however boost oil demand near to medium term.

- **Price forecasts**: Our new 2021 Brent and WTI price forecasts are $66.1/barrel and $62.7/barrel respectively. These constitute substantial upgrades compared with those given in October of $53.8/barrel and $51.3/barrel reflecting greater than expected carryover from 2020, very positive trends in the year-to-date and the bullish market backdrop. Our forecasts for 2022 are $69.3/barrel for Brent and $65.9/barrel for WTI, predicated on strong global GDP growth of 4.5% and a dissipation of the corona virus crisis. We expect prices to soften in 2023 reflecting an influx of supply. Our forecasts are $66.3/barrel for Brent and $62.8/barrel for WTI.

BRENT VS WTI



	1m	3m	12m
Brent $/bbl	+4.0%	+20%	+236%

Source: EIA

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EQUITY RESEARCH

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

EXECUTIVE SUMMARY

Recent oil price developments: Benchmark light crude prices trended powerfully upward in late 2020 and early 2021 to levels few thought possible a year or so ago. The recent spot highs on March 8, 2021 for Brent and WTI were $71.4/barrel and $68.0/barrel, respectively. This took prices back to the levels in the early days of 2020 in the aftermath of the assassination of the Iranian Revolutionary Guard commander General Soleimani. The rebound in prices from the April 2020 spot lows of $9/barrel for Brent and -$37/barrel for WTI we believe has been unprecedented in the annals of the post war petroleum market. After softening modestly through late March, benchmark light crude prices have subsequently trended broadly flat. On April 24, 2021 Brent closed at $66.1/barrel while WTI was at $62.1/barrel. These are comfortably profitable prices for the bulk of oil producers.

The strong upward trend in light crude prices in late 2020 and early 2021 was driven by robust fundamentals and bullish market sentiment. The latter stemmed from the announcement in early November 2020 of the pending availability of potent covid-19 vaccines and upgrades led by the US to global economic growth forecasts. Robust fundamentals reflected a combination of tightly controlled supply under the auspices of the OPEC+ alliance and clear signs of strengthening demand especially in the US and China. In recent weeks, the trend in prices has been dampened by flare-ups in the covid-19 pandemic in various parts of the world, financial market concerns surrounding bond markets yields and the potential for rising OPEC output in the coming months.

Brent-WTI spread: In early 2021, the Brent-WTI spread has remained narrow compared with the experience of the past ten years when at times it has been deep into double-digits. In the first quarter of 2021 it averaged $3.0/barrel (WTI discount) and in late April 2021 was around $3.9/barrel. For comparison, the Brent-WTI spread averaged $7.4/barrel in 2019 and $2.5/barrel in 2020. The narrowing of the WTI discount over the past 15 months or so reflects several structural factors. These include lower production in the US Mid-continent and Texas, an upgrading of the pipeline system from the Cushing, Oklahoma tank farm and from the Permian Basin to the Gulf Coast, falling pipeline tariffs from Cushing and the Permian to the Gulf Coast and higher North Sea output as the giant Johan Sverdrup field has come on-stream. We believe the structural changes to the marketplace will remain largely intact near to medium-term which we expect will keep the WTI discount within the range of the past year or so.

Forward curves: The forward curves for Brent and WTI swung from contango (near month prices lower than for the more distant dates) to backwardation (near month prices higher than the more distant dates) late in the fourth quarter of 2020. The swing coincided with a series of announcements at the beginning of November of the pending availability of highly efficacious covid-19 vaccines. These offered the prospect of an end to the covid crisis and a return to the semblance of normality in the economy. Both the front and middle sections of the Brent and WTI curves are in backwardation through mid-2026. Thereafter, the curves trend broadly flat. Forward Brent prices in the middle section of the curve of around $56/barrel are probably marginal on a fully accounted basis for many deep-water projects but more than adequate for incremental investment. Short lead time tight reservoir development in the US looks to be comfortably viable based on prices over the first twelve months at the front end of the curve of $62-58/barrel.

Supply-demand balance: The EIA estimates that the market remained in substantial deficit to the tune of 2.07mm b/d in the first quarter of 2021. The deficit largely reflected the tight rein on supply by the OPEC+ alliance at a time of strengthening demand. During the second quarter of 2021, a sharp narrowing in the market deficit is likely to be driven by a partial reversal of earlier OPEC+ and Saudi Arabia production cutbacks. Rising Iranian exports to China could also contribute to the loosening. The EIA forecasts a deficit of 1.46mm b/d in the period. Over the balance of 2021 supply looks like outpacing demand growth resulting in a narrowing in the deficits to 0.09mm b/d and 0.34mm b/d in the third and fourth quarters, according to the EIA. Both OPEC and non-OPEC are likely to contribute to supply pressures. We expect demand growth to be historically strong in 2022/23 but think that supply will broadly keep pace resulting in a market trending between approximate balance and a modest surplus. The EIA looks for a deficit of 0.20mm b/d in 2022 and we forecast approximate balance in 2023.

President Biden and oil: As heralded before the November election, President Biden has announced several measures that are hostile to petroleum interests. These include the effective cancellation of the Keystone XL pipeline, the ban on new drilling on federal land and changes to the accounting tax code aimed at disadvantaging oil companies. Other measures are under consideration which will increase the costs of oil and gas development transportation and quite possibly refining. So far, President Biden has avoided any mention of a carbon tax, although this would be a logical measure to further his decarbonisation objectives. We note Canada has already introduced such a tax.

President Biden’s recently announced $2tr American Jobs Plan, about half of which relates to conventional infrastructural programmes, will give a perceptible boost to medium-term petroleum usage. Currently there is no alternative to diesel powered earth moving, construction, transportation and on-site power generation equipment. Substantial amounts of hydrocarbons will also be required in the production of building materials.

Market thesis: We believe the market backdrop will be conducive to a continuing upward trend in petroleum prices over the balance of 2021. The market is expected to remain in deficit, albeit to a lesser extent than in the first quarter. Reflecting rapid economic growth globally of 6% or more, demand should increase at a similar pace. Supply, however, is expected to increase strongly in the coming months led by OPEC and development activity in non-OPEC, with the US and Brazil to the fore. We believe rising production, and occasional flare-ups in covid-19 epidemic will constrain an upward trend in prices in 2021.

In this cycle we believe prices will peak in the first quarter of 2022 with Brent and WTI averaging $73/barrel and $69.5/barrel, respectively. We look for prices to slip over the balance of 2022 reflecting an influx of supply driven by rising OPEC production and development activity in the non-OPEC world. Between the beginning and end 2023 we look for a broadly flat trend in prices. The demand backdrop in 2023 should remain buoyant supported by positive macro-economic influences. We see the critical issue for the oil market outlook over the next year or two as being the direction of the coronavirus crisis. US bond market developments, US climate policy and US sanctions on Iran are also issues of major importance.

Price forecasts: Our Brent and WTI forecasts for 2021 are $66.1/barrel and $62.7/barrel, respectively. These constitute substantial upgrades compared with those given in late October 2020 of $53.8 and $51.3/barrel, reflecting greater than expected carryover from 2020, very positive trends in the year-to-date and the bullish market backdrop. Our forecasts for 2022 of $69.3/barrel for Brent and $65.9/barrel for WTI are predicated on strong global GDP growth of 4.5% and a dissipation of the coronavirus crisis. We expect prices to soften on average in 2023 reflecting supply issues. Our Brent and WTI forecasts for 2023 are $66.3/barrel and $62.8/barrel, respectively.

EXHIBIT 1: ENERGY PRICE SUMMARY

	Brent $/bbl	WTI $/bbl	Henry Hub $/mcf
2020	41.7	39.2	2.11
2021e	66.1	62.7	3.15
2022e	69.3	65.9	3.23
2023e	66.3	62.8	3.65

Source: EIA, Allenby Capital

OIL & GAS MARKET EARLY 2021

PETROLEUM UPSTREAM

Firming demand and constrained supply: After the calamitous conditions of the first half of 2020, the petroleum market has recovered strongly. Indeed, the recovery has been far stronger than generally expected in mid-2020 when the death of the petroleum industry was widely predicted. The strengthening trend over the past nine months or so reflects firming demand, albeit from a historically depressed level, at a time of sharply constrained supply. Since the third quarter of 2020, demand has trended upwards in most major markets as economic activity has firmed globally. The trend was initially driven by China, the second largest petroleum market, but subsequently became more widespread. Particularly significant has been firming demand in the US, easily still the largest petroleum market, from the lows of the second quarter of 2020.

Unprecedented OPEC+ production cutbacks: Greatly assisting the market tightening trend in the second half of 2020 and in early 2021 were unprecedented production cutbacks. These were implemented by both the OPEC+ alliance and independent producers especially in the US and Canada. Cutbacks overall exceeded 13mm b/d. In the US and Canada, cutbacks were financially driven as prices headed below the cash costs of production.

Vaccine announcements in November boosted sentiment: In addition to strengthening fundamentals, oil prices were boosted in early November by the announcement of the arrival of highly efficacious covid-19 vaccines. These offered the prospect of an end to the pandemic and a potential recovery in oil demand in the crucial transportation sectors. The strong upward trend in Brent, the key international light crude benchmark and WTI, the dominant US Mid-Continent light crude, in the fourth quarter of 2020 resulted in considerable carryover strength going into the first quarter of 2021. At the end of 2020, Brent was trading at $51.2/barrel while WTI was at $48.4/barrel, both up about 15% on the fourth quarter averages of $44.3/barrel and $42.5/barrel, respectively. Both were trading about 75% higher than their respective average second quarter lows of $29.5/barrel for Brent and $28.0/barrel for WTI. Very broadly, by end 2020 Brent and WTI had returned to prices which were consistent with petroleum industry fully accounted (including capital costs) breakeven if not profitability. On a cash basis, prices at around $50/barrel, we believe, are generally comfortably profitable.

Strong upward price trend in Q1 2021: Benchmark light crude prices continued to trend strongly upward in the first quarter of 2021 through early March before losing momentum in the closing days of the quarter. Brent reached a spot high on March 8 of $71.4/barrel and a closing high of $69.6/barrel on March 11. For WTI, the spot high was $68.0/barrel on March 8 and $66.1/barrel at the close on March 11. In early March, both Brent and WTI were trading at the highest levels since the early days of 2020 in the wake of the assassination of the high-profile Iranian Revolutionary Guard commander, General Soleimani. By early March, benchmark light oil prices were up over 35% on end 2020 levels and reached solidly if not comfortably profitable levels for the bulk of producers even on a fully accounted basis. Driving prices in early 2021 were the following:

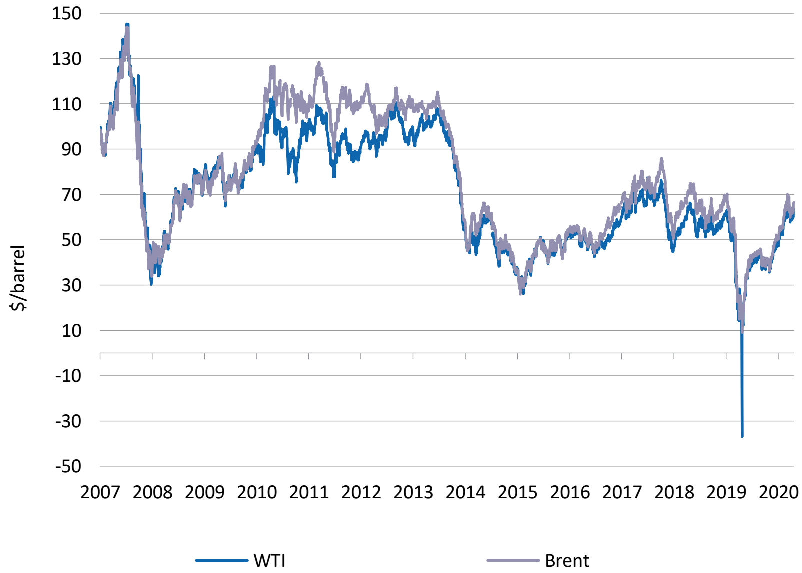
- Bullishness on the vaccine roll-out front, at least in the US and UK.
- The potential for a powerful recovery in the world economy during 2021 reflecting market expectations of the emergence from the pandemic and massive fiscal spending plans in the US in the wake of President Biden's election victory.
- Continuing OPEC+ production restraint with Saudi Arabia's decision to persist with voluntary cuts being particularly influential.
- Buoyant demand in the Asia-Pacific Rim reflecting solid economic growth and extreme winter weather in the more northerly latitudes.
- Bullish near to longer term price forecasts by some high-profile market participants, such as Goldman Sachs.

Dip in mid-March due to financial and covid related factors: After several months of advance, oil prices weakened significantly in mid-March. This reflected in part broader commodity market trends stemming from rising bond yields and a re-evaluation of the demand outlook in 2021 in the light of the disappointingly slow roll-out of covid-19 vaccination programmes, especially in Europe. The recent low for Brent was $60.79/barrel on March 23. This was 13% below the high but still 19 % above end 2020 levels. In the case of WTI, the recent low came in at $57.8/barrel March 23, down on the early March high.

The closing days of March 2021 saw a firming trend in oil prices with Brent and WTI rising to $64.8/barrel and $61.1/barrel respectively on March 29. Rising prices in late March stemmed from several factors. These included the grounding of the Evergreen container ship in the Suez Canal for almost a week, a partial reversal of the upward trend in US Treasury bond yields and industry reports that the OPEC+ production cuts were likely to be extended at the April meeting of the consortium of oil producers.

Flat trend in Brent and WTI between end March and late April: The freeing of the Evergreen vessel on March 30 resulted in a modest softening in benchmark light crude prices. This, however, was partially offset by calls by Saudi Arabia for continuing near-term production restraint by members of the OPEC+ consortium. Between end March and late April, benchmark light crude prices have essentially trended flat at around $65/barrel for Brent and $61/barrel for WTI. A resurgence in covid-19 infections in several parts of the world including India, Japan, Brazil and parts of Europe and North America has tended to dampen market sentiment of late.

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



Source: EIA

SUEZ CANAL SIGNIFICANCE

One of the world's key energy choke points: The 193 km Suez Canal link between the Red Sea and the Mediterranean is one of the world's key choke points for the supply of crude oil, petroleum products and LNG. According to the EIA (Energy Intelligence Agency, the statistical arm of the US Department of Energy), the Canal and the adjacent SUMED Pipeline accounted for 9% of world seaborne trade in petroleum products in 2017. This amounted to about 5.5mm b/d. For LNG, the Suez Canal accounted for about 8% of world trade.

Historically the key flow has been from north to south-----: Historically, the key flow had been from south to north with crude and refined petroleum products and LNG shipped from the Middle East to Europe and the US. The northward flow remains the most significant but has peaked out in recent years. This reflects weakening demand in Europe, a sharp decline in US seaborne imports including from the Middle East and a reorientation of shipments from the Iranian Gulf to the rapidly growing markets of East and South Asia, notably China and India.

------but southerly flow has been increasing of late from the Black Sea: Offsetting the weakening northward flow in the Suez Canal has been an increasing southerly flow. This stems from rising shipments of Urals crude from Black Sea ports to Asian markets. The southerly flow could gain an extra boost should Libyan production be restored to historical levels on a sustained basis.

LNG

Rollercoaster ride over the past year: LNG prices have been on the proverbial rollercoaster ride over the past year. Taking JKM (Japan Korea Marker), the East Asia benchmark, it started 2020 at around an historically depressed $5/mm Btu cif (cost of insurance and freight or delivered to the port of entry) reflecting a mild winter weather in northern Asia and high inventories. Late in the first quarter and during the second quarter of 2020, the JKM came under heavy pressure as covid-related restrictions on economic activity sharply depressed demand. In June, the JKM plumbed an all-time low of under $2/mm Btu cif. This was clearly a highly unprofitable level regardless of source.

Lowest cost producers need about $4/mm Btu to breakeven: According to the Oslo-based energy consultancy Rystad, the lowest cost producer Qatar needs about $4/mm Btu to breakeven, although this depends in part on fluctuations in transport costs. For US producers selling into East Asia the breakeven point is probably around $6.5/mm Btu reflecting a Henry Hub price of about $2.5/mm Btu and another $4/mm Btu for liquefaction and transportation. Again, fluctuations in transport costs impact breakeven points. Fortunately for suppliers, weak LNG prices in the second quarter of 2020 were partly offset by depressed shipping rates.

JKM marker rose strongly in H2 2020 from $2/mm Btu----The JKM marker price recovered strongly in the second half of 2020. This reflected the Chinese and other Asian economies regaining upward momentum and supply constraints. The latter related particularly to unplanned maintenance outages and technical issues at three LNG facilities onshore and offshore Western Australia and congestion in the Panama Canal. These factors adversely impacted shipments from the US Gulf Coast to East Asia. By end 2020 the JKM was around $10/mm Btu. The average for 2020 as a whole was about $4.3/mm Btu, down 22% on the previous year and at least an 11-year annual low.

-----and peaked at $33/mm Btu in January 2021: During early to mid-January 2021 the JKM marker spiked to an unprecedented $33/mm Btu. This reflected both extreme weather conditions in north eastern Asia and severe supply constraints both for LNG and piped gas from Kazakhstan into China. By end January 2021, however, the spike had largely reversed leaving the JKM at around $8/mm Btu. The rapid reversal related to a return to more normal weather and an easing of supply constraints. By early March 2021, the JKM marker was trading at just under $6/mm Btu but towards end month had firmed to $6.8/mm Btu driven in part by logistical uncertainty related to the recent Suez Canal blockage.

JKM trading at over $8/mm Btu in late April 2021: The trend has continued to firm in April with spot JKM trading at over $8/mm Btu towards end month. Prices have apparently been buoyed by strong Chinese demand reflecting both robust industrial activity and high rates of gas storage injection. It should be noted that in NE Asia there are now two seasonal peaks in usage with one in the winter and the other in the summer. The latter reflects heavy electrical power requirements related to air conditioner usage. CME forward prices show the JKM marker trending flat during the summer months at about $8.5/mm Btu. During the 2021/22 winter months, the JKM peaks at $9.8/mm Btu before dipping to around $6.2/mm Btu in the third quarter of 2022. Between the second half of 2022 and 2026 JKM forward prices range between about $5.4/mm Btu and $8.4/mm Btu based on CME data.

CRUDE OIL SPREADS

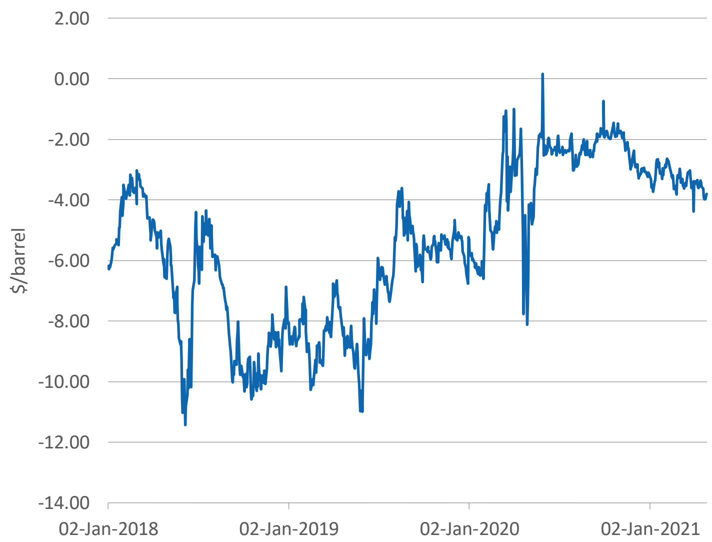
BRENT-WTI

Spread narrowed significantly in 2020 and in late April was about $3.9/barrel: Brent and WTI are both high-grade light, sweet crudes with specifications of 37.5° API and 0.4% sulphur and 41.4° and 0.4% sulphur, respectively. The Brent-WTI spread (WTI discount), the most influential of the light crude benchmarks, narrowed significantly between 2019 and 2020. Furthermore, since the second quarter of 2020 the spread has trended within a relatively tight range compared with the prior ten years or so. Looking at 2020 the quarterly picture was as follows: Q1 $4.7, Q2 $1.5, Q3 $2.1 and Q4 $1.8. For the year, the spread averaged $2.5/barrel well down from the $7.4/barrel of 2019 and the narrowest since the $0.5/barrel of 2016. During the first quarter of 2021 the Brent-WTI spread averaged around $3.0/barrel. In March 2021, it ranged between about $3.0/barrel and $4.3/barrel and in late April was $3.9/barrel.

Structural factors including upgraded pipeline links have driven the narrowing: The narrowing in the Brent-WTI spread over the past 15 months has reflected three key structural factors. Firstly, the significant drop in oil production in Texas and the Mid-Continent post early 2020. Secondly, the combination of rising North Sea output between 2019 and 2020 and sluggish demand in Europe. North Sea output unusually in 2020 rose 7% driven by the giant Johann Sverdrup field coming on-stream in the Norwegian sector. Thirdly, a radical expansion of the pipeline capacity over the past two years or so between the Cushing tank farm, the settlement point for NYMEX crude, and the Gulf Coast and from the Permian Basin to the Gulf Coast. This has helped prevent the excessive build-up of inventory at Cushing which has occurred from time to time in recent years and depressed spot WTI in the process. The increasing availability of pipeline capacity has also depressed pipeline tariffs from Cushing to the Gulf Coast.

We expect the structural changes to remain largely intact near to medium term in the absence of exogenous shocks. This should keep the WTI discount within the range of the past year or so.

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



Source: Refinitiv

SWEET-SOUR

Tight supplies of sour grades: Sweet-sour spreads need to be looked at regionally given variations in specifications and supply-demand dynamics. The key regions are the US Gulf Coast, the US Mid-West, Europe, and the Middle East. Sour grades which are characterised by low API gravity (typically below 30º) and high sulphur content (typically above 0.5% by weight) usually sell at a significant discount to the sweet grades and for this reason are often prized by refineries which have invested in the complex facilities (hydrocrackers and cokers) required for processing. Sour discounts have tended to narrow in most regions in recent years due to discoveries being orientated to light sweet grades and major producers of heavy grades notably Venezuela and Iran, being subject to swingeing sanctions regimes. Mexico and Colombia other key suppliers of heavy crude has also been subject to rapid depletion rates.

Mars and Maya trading at historically narrow discounts to WTI at end April: Looking at the US Gulf Coast, the benchmark sour grades are medium-heavy Mars sourced from the US Gulf of Mexico and the heavy Maya grade sourced from Mexico. Reflecting widespread refinery outages during February 2021, Gulf Coast sour discounts widened but as facilities came back on-stream in March they largely evaporated. By end month Mars and Maya were trading at approximate parity with WTI. Reflecting the tight supplies of sour crudes along the Gulf Coast Mars has traded at a premium to WTI of $0.51/barrel in 2021 year-to-date based on OPEC data. In late April Mars and Maya were trading at historically narrow discounts to WTI of $0.36/barrel and $0.68/barrel, respectively.

Historically low WCS discount of $11-12/barrel: In the US Mid-West several refineries have been upgraded to process the ultra-heavy and sour Western Canada Select (WCS) grade from the Alberta oil sands. WCS traded at a discount of $11-12/barrel in March and April. This reflects a narrowing from around $16/barrel at end 2020 and is towards the low end of the historical range for the discount. The moderate discount probably reflects the subdued trend in oil sands output of late and an easing of logistical bottlenecks.

Urals discount to Brent normalized of late at about $2/barrel: In Europe and particularly in the Mediterranean, Urals is a popular medium-grade sour crude. This has an API of 31.4º and a sulphur content of 1.4% and is a blend of sour crude from the Russian Volga region and sweet crude from Western Siberia. During the first quarter of 2021, Urals traded between a discount of about $2/barrel and parity with Brent. The discount tended to widen in April hitting around $3.3/barrel early in the month but late in the month was back to about $2.3/barrel. Broadly speaking, the Urals-Brent relationship has normalized in recent months after an abnormal period in the third and fourth quarters of 2020 when Urals had traded at significant premiums to Brent. The normalisation, we believe, reflects apparently weak refinery demand in the Mediterranean for sour grades plus supplies of Urals grade oil increasing following the easing of restrictions as part of the OPEC+ cutback programme.

Dubai trading at a modest $0.9/barrel discount to Brent: The key medium sour grade in the Middle East is Dubai. It has an API of 31º and a sulphur content of 2% and is popular with Asian refineries. Historically, Dubai has traded at a discount of a dollar or two to Brent reflecting its sour specification. In recent years, however, Dubai has tended to trade close to parity with Brent and from time to time has swung to a premium. In 2021 year-to-date, Dubai has traded at a modest discount of $0.86/barrel to Brent.

FORWARD CURVES

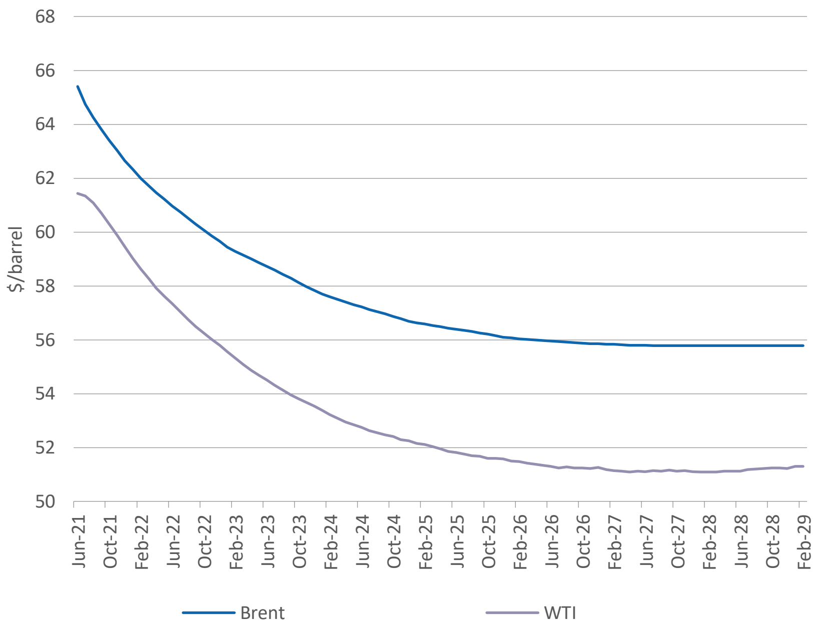
Swing from contango to backwardation in Q4 2020: The forward curves for both Brent and WTI swung from contango (near month prices lower than for the more distant dates) to backwardation (near month prices higher than the more distant dates) late in the fourth quarter of 2020. The swing coincided with the announcements in November of the pending availability of highly efficacious vaccines which held out the prospect of an end to the coronavirus crisis and an economy with at least the semblance of normality.

Backwardation persisted through late 2021: Both the Brent and WTI curves have remained in backwardation through April 2021 which contrasts with the pronounced contango of a year ago. Growing evidence of a powerful recovery in the US economy and strengthening petroleum consumption has tended to reinforce the backwardation Conceptually backwardation reflects tight near-term availability which although possibly characterising the situation in China seems less apparent elsewhere. OECD commercial inventories, for example, remain above the five-year average. Hedging activity is possibly contributing to the downward slope on the front-end and middle sections of the curve.

Front to middle section of the curve in backwardation through mid-2026: Brent and WTI forward curves are both in backwardation through mid-2026. The curves then flatten over the following two to three years. From early 2029 WTI swings to a very mild contango. The backwardation on the front ends of both curves is relatively pronounced. In the case of Brent, the 1 -to-3 -month spread is $1.6/barrel while the 1-to- 12-month spread is $4.4/barrel. For WTI the comparable spreads are $0.7/barrel and $4.1/barrel, respectively. The dipping away of the curves at the front end is consistent with a rapid easing of supply pressure. We believe this is most likely to be manifested in terms of an increase in OPEC production.

Long lead time deep water projects possibly vulnerable but short cycle shale projects still looking comfortably viable: Arguably the forward curve has more relevance for investment decisions than spot prices. Looking out to the middle of the Brent curve in the 2025/26 timeframe forward prices are around $56/barrel. This is probably marginal on a fully accounted basis for many standalone deep-water projects but constitutes a comfortably profitable price for incremental offshore investments. It should be noted that in the world's newest offshore development, the Liza field offshore Guyana, Hess Corporation gives the breakeven price as only $35/barrel in phase 1 and $25/barrel in phase 2. This sits very much at the low end of the deep-water cost curve. Lead times on US shale projects are short cycle at around six to nine months assuming land is already purchased or leased. Forward WTI prices of $62-58/barrel at the front end of the curve over the first 12 months are, we believe, generally sufficient to comfortably undertake tight reservoir development in the US Mid-Continent and Texas.

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



Source: Refinitiv

US SCENE

DRILLING ACTIVITY

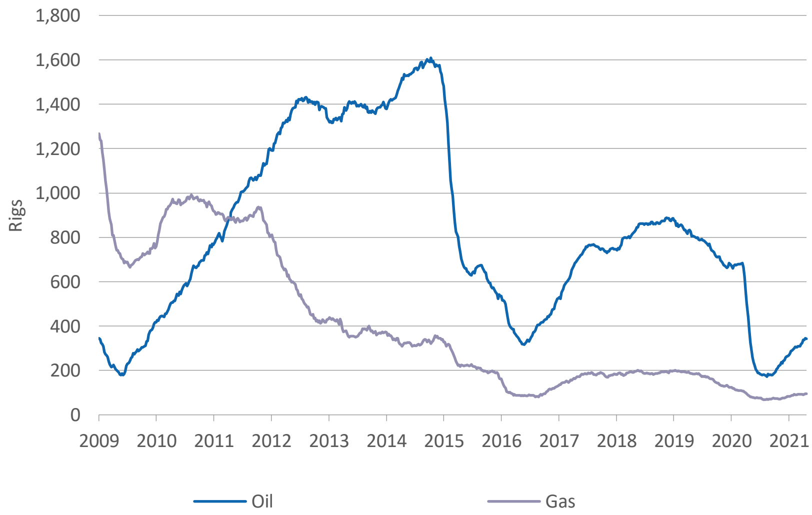
Recent oil-directed trends

Upward trend in the rig count since August 2020---: After the precipitous fall in the second quarter of 2020, the US oil-directed rig count bottomed in August/September. Based on Baker Hughes data, the low point came in mid-August at 172 rigs, down 75% from end 2019 and 80% from peak levels in recent years in November 2018. Since mid-August 2020, the rig count has trended consistently higher and by April 16 was 344, double the low point and a 15-month high but still 61% below the peak levels of the fourth quarter of 2018.

-----reflecting strengthening in petroleum economics: The upward trend in recent months reflects the clear strengthening in petroleum industry economics as WTI has moved decisively above $40/barrel on a sustained basis. We regard this at base as broadly consistent with fully accounted breakeven in the principal tight reservoir basins of the Mid-continent. It should also be noted that the discounts to WTI for crude produced in some of the more remote basins such as the Bakken/Williston have tended to narrow over the past year or two. In late April 2021 Williston Sweet, for example, was selling at $56/barrel a discount of about $5/barrel to WTI. In recent years, the Williston discount has often been comfortably in double digits.

Permian Basin continues to make the running: The Permian Basin of west Texas and south east New Mexico continues to make the running in drilling activity. For the week ending April 16, the rig count here of 226 accounted for 66% of the US onshore total and was up 95% on the mid-August 2020 low. The next largest contributors to the rig count on April 16 were the Eagle Ford, Bakken, Cana Woodford and Niobrara which accounted for 9%, 4%, 3% and 2% respectively. A miscellaneous group accounted for 14% of the rig count. The Permian remains the basin of choice for drillers reflecting the potential for multi-stacked reservoirs, above average well EURs (estimated ultimate recovery rates) and attractive economics.

EXHIBIT 6: BAKER HUGHES US RIG COUNT (RIGS)



Source: Baker Hughes

OIL-DIRECTED DRILLING OUTLOOK

One school of thought suggests drilling will be constrained by financial constraints------

The key question now is how US drilling activity and the rig count might develop in the coming months in the light of the emergence of comfortably profitable prices. There are two views on the subject. The first is that drilling activity will remain subdued compared with the historical experience given that the major producers have largely committed to a disciplined approach with the emphasis on financial returns rather than volume. Advocates of this view also argue that small to medium sized producers are financially constrained by heavy debt loads and a reluctance of debt providers and shareholders to supply capital for new projects.

-----and the other that $60+ oil will be difficult to ignore: The alternative view is that with WTI hovering at $60/barrel plus, which offers the prospect of comfortably profitable returns, opportunistic producers will not be able to resist the temptation to bring new wells online. This argument is reinforced by the short lead times required in the US to drill wells in onshore basins and the typically ready availability of drilling locations. Several other factors suggest that drilling activity might gather pace faster than consensus opinion would suggest. These include the following:

- Well depletion rates in the tight reservoir basins of the Mid-Continent and Texas are high and can be 50%-60% in the first year. To merely maintain production, it is therefore necessary to sustain a high level of drilling activity.

- Financial performance and volume are related in an industry with sizeable, fixed costs. Falling volume can rapidly translate into rising unit cost, falling margins and declining cash flow. Small to medium sized producers also have little bearing on prices, as in other commodity sectors.

- For those producers with large acreage positions, there may be an argument for as rapid development as possible assuming comfortably profitable prices. The issue here is the potential for stranded assets. A danger is that the federal authorities in support of decarbonisation objectives could attempt to accelerate the winding down of petroleum usage by, for example, introducing a carbon tax on an escalating scale as in Canada.

Medium-sized nimble operators will probably drive the rig count higher: In conclusion, we believe that providing WTI remains anywhere near $60/barrel the US rig count is likely to trend steadily higher over the balance of 2021. This, we believe, will be driven initially by the medium-sized nimble operators with the large concerns joining the party much later and possibly not before 2022.

RECENT GAS-DIRECTED DRILLING TRENDS

Long secular downturn in gas-directed drilling----Gas-directed drilling was on a secular downward trend in the US between 2008 and mid-2020. Over this period the rig count dropped from about 1,600 to 68 reflecting a dramatic deterioration in production economics. Over the period gas prices came under heavy pressure as a result of surging production both in the Appalachian Basin and as a by-product of oil-directed development in major basins in the Mid-Continent and Texas. Interestingly, gas-directed drilling in the Appalachian Basin was supported by prolific natural gas liquids production.

----- but the trend has recently firmed from a low base: From the low point in July 2020 gas-directed drilling has trended higher, albeit from a low base. By April 16, the gas-directed rig count had climbed to 94. The upward trend in recent months is correlated with a firming in gas prices with the Henry Hub benchmark consolidating around $2.65-2.75/mm Btu against $1.5/mm Btu at times in the second quarter of 2020. We believe however that $2.75/mm Btu is not much above breakeven. A surge in gas directed drilling in the US in the coming months is therefore not expected.

DRILLING ON FEDERAL LAND AND OFFSHORE

Joe Biden true to his word on making drilling more difficult: During the 2020 presidential election campaign Joe Biden campaigned for a ban on drilling on federal land and offshore in support of a policy promoting renewable energy. On becoming President, Joe Biden rapidly enacted a moratorium on issuing new exploration licences on federal land and offshore. This was firstly for 60 days and then 100 days. In practice we think the moratorium will apply at least as long as the Democrats are in power. Near-term, the licence moratorium is likely to have little impact on drilling activity or oil and gas production. Existing production is secured by licences already granted.

Long term drilling activity and hence production could be hit by the Biden ban by reducing the number of potential drilling locations. The state most likely to be impacted by the ban is New Mexico where over 50% of land is federally owned. Interestingly, New Mexico is a Democrat leaning state and has a Democrat governor and two US senators. New Mexico draws highly significant revenues from royalties and oil and gas related taxes.

CRUDE PRODUCTION

Crude oil trend

Production trended sharply down for five months from all-time high in Q1 2020: The long upward trend in US crude oil production from the 2008 low of 5.00mm b/d was decisively broken in 2020. After reaching an all-time high of 13.05mm b/d in late March 2020 the four-week average collapsed over the subsequent five months or so. The low point was early September 2020 when production came in at 10.30mm b/d, a hefty 2.75mm b/d below the March peak. The average production rate for 2020 was 11.32mm b/d, down 8% on a year previously and only the second annual decline since 2008. The other was in 2016 and was 6%. The sharp downturn in crude production in the second and third quarters of 2020 was driven by rapidly declining drilling activity, high rates of well depletion in tight reservoir basins and conventional well shut-ins due to poor economics.

Firming underlying trend in recent months: Since early September 2020, US crude production has trended upward. By late 2020 production had risen to 11.05mm b/d. The trend flattened in the first quarter reflecting the impact on production in late February and early March of unusually severe winter weather in Texas. After dropping to a low of 10.35mm b/d in early March. production has subsequently recovered to 11mm b/d.

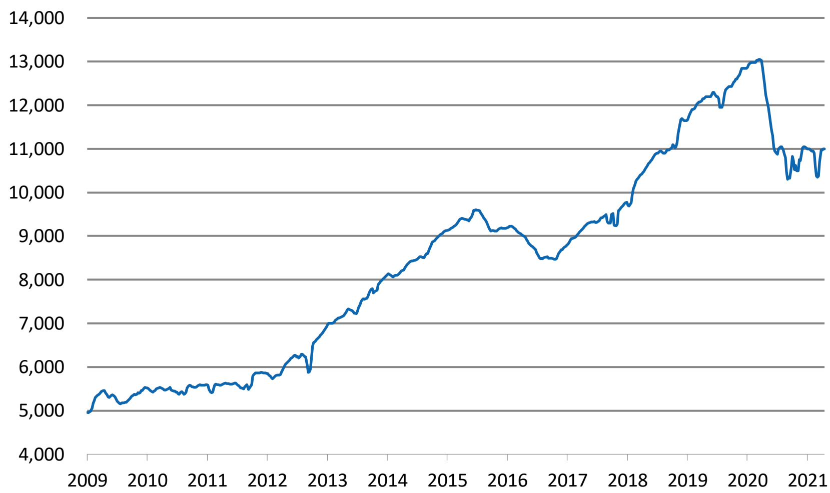
US crude production should trend significantly upward in the second quarter. This reflects the following:

- The reinstatement of previously shut-in wells given the decisive improvement in well economics in recent months.
- The lagged response of production to rising drilling activity in the tight reservoir basins. Based on casual empiricism, major changes in drilling tend to impact production rates with a lag of four to six months.
- Declining DUCs (drilled but uncompleted wells) which suggests that new fully completed wells (fracked with artificial lift added) are being brought on-stream having previously been held in inventory.

Rising rig count should drive production up in Q3 and Q4: Assuming the rig count continues to trend higher, rising crude production is also in the cards for the third and fourth quarters of 2020. After averaging 10.75 mm b/d in the first quarter of 2021, the EIA is looking for US crude production to come in at 10.93mm b/d, 11.13mm b/d and 11.35mm b/d in the second, third and fourth quarters of 2021, respectively. The average for 2021 would be 11.04mm b/d, a dip of 2.4% compared with 2020. For 2022 the EIA is forecasting US crude production of 11.86mm b/d (+7.4%) which is within shooting distance of 2019's all-time high of 12.25mm b/d. Given the strength of drilling activity in recent months, we believe the EIA's forecasts for 2021 and 2022 could be conservative.

2019 annual high likely to be exceeded by 2025 but 15mm b/d target uncertain: We believe that 2019's record production is likely to be exceeded by 2025 given the bullish economic backdrop in the US and the apparent availability of undeveloped resources in the principal US tight reservoir basins. Whether or not crude production can exceed 15mm b/d, as was widely expected by industry observers a few years ago, is more debatable in the wake of a Biden presidency. Joe Biden is probably going to make life considerably more difficult and expensive for the petroleum industry in the coming years.

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



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

EXHIBIT 8: US CRUDE OIL QUARTERLY PRODUCTION

	Q1	Q2	Q3	Q4	Total
2018 mm b/d	10.25	10.52	11.25	11.82	10.96
YOY %	13.4	15.2	20.6	19.4	17.2
2019 mm b/d	11.83	12.13	12.25	12.78	12.25
YOY %	15.4	15.3	8.9	8.1	11.8
2020 mm b/d	12.75	10.81	10.81	10.90	11.32
YOY %	7.8	-10.9	-11.8	-14.7	-7.6
2021 mm b/d	10.75	10.93	11.13	11.35	11.04
YOY %	-15.7	1.1	3.0	4.1	-2.5
2022 mm b/d	11.54	11.74	11.18	12.18	11.66
YOY %	7.3	7.4	0.4	7.3	5.6

Source: EIA. Note: Data from Q1 2021 are estimates/forecasts.

NATURAL GAS LIQUIDS AND HYDROCARBON SUBSTITUTES

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

NGL output has continued to trend higher in 2020/21: Contrary to crude, US NGL output rose significantly in 2020 and has continued to trend higher in 2021. NGL output rose by 7% to a record 5.16mm b/d in 2020 and in the latest four-week period to April 16 showed a year-on-year gain of 1.3% to 5.12mm b/d. The gains in NGL's, have been supplemented in 2021 by a 45% increase in ethanol production which is up 45% year-on-year in the most recent four-week period. NGL production continues to be driven by buoyant demand for ethane which is the key feedstock for ethylene and other polymer products. Significantly, the availability of ethane in the US has resulted in sizeable investment in new ethylene production facilities of late. Buoyant demand has helped lift ethane prices thereby encouraging the separation of the liquid from the natural gas stream. The EIA is forecasting gains in US NGL production of 2.1% to 5.27mm b/d in 2021 and 9.9% to 5.8mm b/d in 2022.

Ethanol output should rise in 2021/22: The principal use of ethanol is a bio-fuel additive to gasoline which helps reduce toxic emissions but at the expense of energy intensity (increases fuel consumption). Weak gasoline demand in 2020 therefore reduced ethanol usage resulting in a decline in production. In 2021 ethanol production was adversely impacted by severe weather conditions which for a time in February restricted the supply and boosted the price of natural gas to uneconomic levels for ethanol mills. During March, however, production partially recovered and should receive a further lift now that gasoline demand is regaining upward momentum. The EIA is looking for ethanol production to increase by 5.5% to 0.96mm b/d in 2021 and 3% to 0.99mm b/d in 2022.

PETROLEUM AND OTHER LIQUIDS PRODUCTION

Easily the world's largest producer of hydrocarbon liquids and ethanol: The US is easily the world's largest producer of both crude and crude plus NGL's and hydrocarbon substitute liquids. In 2020 US production of all liquids came in at 18.60mm b/d, down 4.5% on a year earlier with the decline in crude partly offset by the gain in NGLs. Despite the drop, US production of liquids in 2020 was the second highest on record. The number two and three producers Russia and Saudi Arabia both produced about 10.5mm b/d in 2020 and therefore significantly behind the US. In the year-to-date early April 16, 2021 liquids production was running at 17.9mm b/d, down 10% on a year earlier.

Roughly unchanged liquids output in 2021: The EIA is forecasting roughly unchanged US liquids production in 2021 at 18.61mm b/d with higher NGL and biofuels output offsetting lower crude production. After a weak first quarter depressed by adverse weather conditions, the trend is forecast to strengthen strongly over the balance of 2021. In 2022 the EIA is looking for US liquids to rise by 7.8% to a record 20.07mm b/d driven by strong gains of 7.4% in crude and 9.9% in NGLs.

PIPELINE STATUS

Irreconcilable conflicts: Considerable controversy has swirled around four major trunk pipeline projects in the US and Canada for some time. The five are Keystone XL, Enbridge 3, Trans Mountain and Dakota Access. Controversy reflects an essentially irreconcilable conflict between two coalitions. On the one hand are pipeline owners and petroleum producer interests, local/state government and businesses and those seeking well paid employment and on the other left-wing political groups, environmentalists, tribal interests and on occasion landowner interests.

The thinking of the left-wing politicos and environmentalists is that by blocking pipelines oilfield development economics for landlocked resources will be severely impacted, thereby reducing the attraction of investment. Their logic is along the right lines, but they should remember that more output will be transported by rail and truck if pipeline development is embargoed. The alternatives to pipelines are not only less safe for shipping petroleum but also more energy intensive operationally.

KEYSTONE XL

Alberta oil sands to Midwest and Gulf Coast project: Calgary-based TC Energy's Keystone XL pipeline was scheduled to go the 1,200 miles from Hardisty Alberta to Steele City Nebraska via a direct route and in so doing link the Alberta oil sands with the Gulf Coast refining complex. The capacity would have been 900,000 b/d. Gulf Coast refineries are typically well adapted to processing the heavy Alberta oil. They are seeking new sources of such oil to replace declining availability of heavy South American heavy crude either due to depletion or in the case of Venezuela US sanctions. Keystone XL has been constructed in Canada where it is in use. A more circuitous easterly route is available from Hardisty via Saskatchewan, Manitoba, North Dakota and South Dakota to Steele City. From here there are links either to the Patoka City, Illinois or Cushing, Oklahoma tank farms.

Joe Biden withdraws the permit thereby cancelling the project: Good to his word in the election campaign, President Biden duly withdrew the Keystone XL permit on entering office. We believe it is very unlikely that Keystone XL will be resurrected even though much of the pipe has been laid. There are also reputed to be 48,000 tonnes of pipe in storage. We suspect, however, TC Energy will sue the federal government in due course. The bill is likely to be substantial.

DAKOTA ACCESS

Bakken to Midwest pipeline: The 570,000 b/d Dakota Access pipeline extends over 1,030 miles linking the Stanley North Dakota hub at the heart of the Williston Basin (Bakken) with the Patoka, Illinois tank farm. The pipeline is responsible for transporting approaching 50% of the Bakken's output. Dakota Access commenced operations in May 2017 after considerable rancour between on the one hand the operator and oil companies and the other environmental and tribal groups. Permitting was originally granted by the Trump administration but was withdrawn following a decision by a US District Court that a new Federal environmental review was undertaken. During the review, the Court demanded that the pipeline not only cease operations but also be emptied. Much to the relief of the petroleum interests involved the Biden administration overrode the Court and gave permission to keep the Dakota Access open pending the outcome of the environmental review.

Operational pending the outcome of an environmental review: It is not clear how long the Dakota Access environmental review will take. We could be looking at merely a stay of execution. An order to close the pipeline would potentially have disastrous consequences not only for the petroleum industry operating in North Dakota but also the economy of the state. The first consequence would probably be a widening in the Bakken price discount for one of the most remote major petroleum basins in the lower 48 states.

Chaos likely in the event of closure: Doubtless an attempt would be made to ship oil via Enbridge's 250,000 b/d Stanley to Clearbrook, Minnesota pipeline but this has inadequate capacity to offset the closure of Dakota Access. Rail transport offers a significantly more expensive option to shipping oil to Midwest refineries and would necessitate a widening in the discount of Williston Basin oil to WTI. In the event of a closure order, the owners and users of Dakota Access may have strong grounds for suing the federal government which is possibly one reason why the Biden administration overrode the earlier District Court verdict.

ENBRIDGE 3 REPLACEMENT

Replacement pipeline from Alberta to Midwest: The 740,00 b/d Enbridge 3 Replacement is a 1,100-mile pipeline running from Hardisty, Alberta to Superior, Wisconsin where it links to pipelines supplying Midwest refineries. It is a replacement for an existing pipeline that commenced operations in 1968 and is now in poor condition. The new pipeline operates at higher pressures than those currently prevailing and doubles existing capacity. It links the Alberta oil sands with the refineries of the Midwest several of which, such as

BP's Whiting facility (among the largest refineries in the US) near Chicago, have been adapted for using heavy, high sulphur crude.

Enbridge 3 has been completed in Canada, North Dakota and Wisconsin. The remaining area of contention concerns the 335-mile Minnesota section. Work continues on the pipeline. An injunction brought against Enbridge by environmental and tribal groups was dismissed a few months ago but the Minnesota Democrat Governor, Tim Walz, has appealed against the decision. A verdict is awaited. Enbridge is optimistic that it can complete the pipeline by end 2021 as currently scheduled. We believe a degree of optimism is justified given that the new pipeline is a replacement and the not insignificant economic advantages. Joe Biden is doubtless hostile to the completion of the Enbridge 3 Replacement but whether he would be willing to veto the project at this late stage with all the ensuing chaos and potential legal and other costs is an open question.

TRANS MOUNTAIN

Alberta oil sands to Vancouver pipeline twinning: The Trans Mountain pipeline covers 1,150 km from Edmonton, Alberta to Burnaby east of Vancouver, British Columbia. The project involves twinning an existing pipeline between the two locations which will boost capacity from 300,000 b/d to 890,000 b/d. The new pipeline will ship heavy oil from the Alberta oil sands while the historic pipeline will be used for light products. Significantly, the Trans Mountain will give the oil sands direct access to Asian markets for the first time. Particularly now that Keystone XL has been cancelled, construction of the Trans Mountain pipeline is crucial for the development of the Alberta oil sands, given their land locked location.

Federally owned and 22% complete: The Trans Mountain pipeline project was originally operated by pipeline major Kinder Morgan but was acquired by the federally owned Canada Development Corporation in August 2018. This followed a trade dispute between the provincial governments of British Columbia and Alberta and interminable lawsuits brought by First Nations and environmental groups. Construction work on Trans Mountain restarted in early 2020 and as of April 2021 was 22% complete, according to Canada Development Corporation. Completion is scheduled by end 2022.

Likely to be completed in our view: We believe the Trans Mountain is likely to be completed on schedule barring exogenous events. It is not beholden to the vagaries of US politics and lawsuits and given that it is state owned is arguably less susceptible to Canadian domestic political and legal objections. The federal government's plan is to sell the Trans Mountain project at what it considers an appropriate time. Based on press reports, First Nations groups will probably be a member of any buy-out consortium.

Viability questioned: The cost of the Trans Mountain pipeline has been put at C$12.6m by the Canadian Development Corporation, well up on the C$5.4m originally estimated. Cost escalation combined with potentially falling demand and rising oil sands costs due to actual and prospective hikes in the federal government's carbon tax have led some, such as the Simon Fraser University, to question the viability of the Trans Mountain pipeline. Major oil sands operators such as Canadian Natural Resources and Suncor, however, have already committed to using the bulk of its capacity.

INVENTORIES

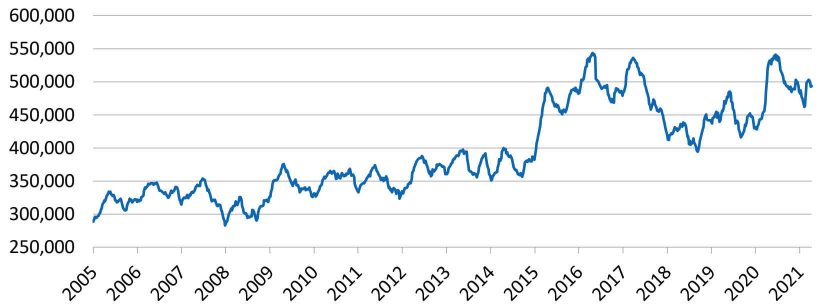
Crude oil

Trending within the seasonal range: US commercial crude oil inventories are currently trending within the seasonal range for the time of year and are well down from the highs of mid-2020 when they reached about 540mm barrels. In the four weeks ending April 16, 2021 inventories stood at 493.0mm about the same as a year earlier and 1% higher than the seasonal average. Days' supply has also been trending down from peak levels of over 41 in the second quarter of 2020. In the week to April 16, 2021 crude inventories were running at about 33 days' supply. This compares with 39 days a year earlier and a typical

25 to 30 days in recent years. Prior to the mid-2000s and the upsurge in domestic production days' supply tended to run more in the range of 20-30.

We believe that with US demand now gathering pace, US inventories should trend well within the seasonal range historically. The days' supply should also decline reflecting rising refinery utilisation.

EXHIBIT 9: US CRUDE OIL INVENTORIES (THOUSAND BARRELS)



Source: EIA

Cushing

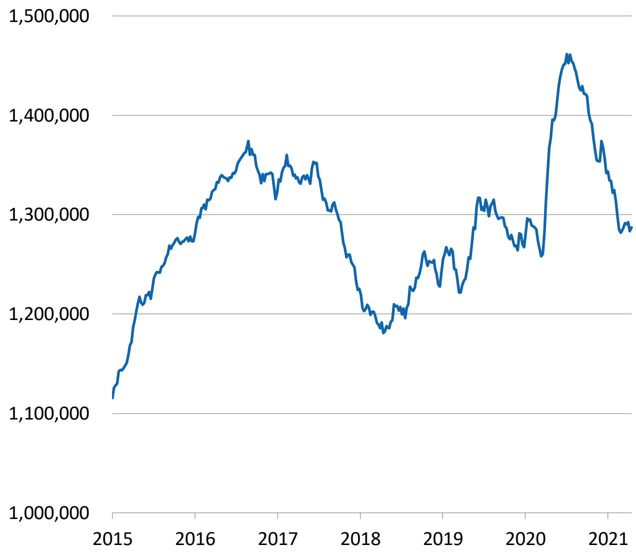
Inventories are comfortable historically: Cushing, Oklahoma is the location of the largest tank farm and oil trading hub in the US. Significantly, it is the settlement point for WTI on Nymex. Crude inventories have been on a clear downward trend since peaking at about 65mm barrels in May 2020. For the week ending April 16, 2021 crude inventories stood at 45.4mm barrels, down 14.3mm barrels on a year earlier and a comfortable level historically. Based on reported capacity of about 76mm barrels the utilisation rate is 60%.

We believe for the foreseeable future inventory levels at Cushing should remain well within the tank farm's capacity constraints. The pipeline infrastructure from the Mid-Continent and the Permian to the Gulf Coast refinery complex has been significantly upgraded in recent years thereby removing what was a bottleneck at Cushing as production expanded. Near-term, rising refinery utilisation along the Gulf Coast should also constrain inventory accumulation in the absence of pipeline technical issues.

CRUDE AND PRODUCT INVENTORIES

Crude and product inventories are roughly back to Q1 2020: Given fluctuations in refinery utilisation and crude oil and product imports and exports, the most insightful way of looking at inventories is on an all-encompassing basis. This includes both crude oil and refined product. After peaking at what was probably an all-time high of 1,462mm barrels in July 2020 US commercial crude and product inventories have been steadily trending down. In the week ending April 16, 2021they stood at 1,287mm barrels, down 12% from the July 2020 high and roughly back to pre-covid crisis levels in early first quarter 2020. This is equivalent to about 67 days' supply against 81 days at the July 2020 peak. At end 2019 total commercial inventories were around 61 days' supply.

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



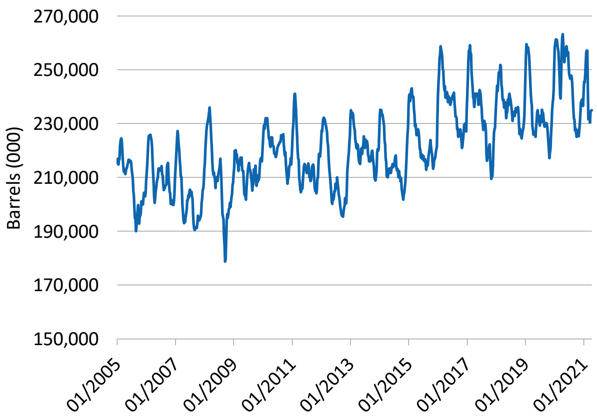
Source: EIA

GASOLINE

Refinery outages have kept inventories below average seasonally: US gasoline inventories fell sharply seasonally in February following the disruptions to the Gulf Coast refinery complex resulting from severe weather. Reflecting this and firming demand, inventories have trended of late at or below the lower end of the seasonal range. In the week ending April 16, 2021 gasoline inventories were 235mm barrels, 11% below a year earlier and 3% below the average for the time of year. As the peak driving season approaches in end May, gasoline inventories could remain relatively tight.

In terms of days' supply, gasoline inventories have also been on a declining trend of late. For the week ending April 16 days' supply was 26.3 against 47.6 a year earlier and 29.8 at end 2020. Looked at from a longer-term perspective gasoline inventory days' supply are at normal levels.

EXHIBIT 11: GASOLINE INVENTORIES



Source: EIA

DISTILLATES

Seasonally normal levels: US distillate inventories are running at seasonally normal levels currently based on the experience of the past five or ten years. For the week ending April 16 they stood at 142.4mm barrels which is roughly in the middle of the seasonal range. Compared with a year earlier, inventories were up 4% but down 6% from end 2020 levels. The days' supply on April 16 were 36.1. This was significantly lower than the year earlier 40.3 days of a year earlier but broadly in line with the experience of the past ten years.

Propane and propylene

Propane is a gaseous hydrocarbon that is easily liquefied. The bulk of it is produced as a by-product of natural gas production but significant quantities are also derived from light crude and refinery gases. We believe significantly more than 50% of usage is fuel-related for space heating, cooking, drying, water heating, industrial vehicles and furnaces. The balance is mainly used to produce propylene, a precursor for producing a wide range of chemical resins, fibres, elastomers and other chemical products. Propane inventories fluctuate sharply seasonally reflecting the use of the product in space heating and in drying particularly for agricultural commodities post harvesting. The typical pattern is for inventories to be accumulated in the third and early fourth quarters and run-off from late in the fourth quarter and through the first and second quarters.

Inventories at the low end of the seasonal range: The seasonal run-off was particularly pronounced in the first quarter of 2021 due at times to severe weather conditions which restricted propane supplies and buoyed demand for heating. This resulted in inventory trending downward close to the low end of the seasonal range. For the week ending April 16, propane inventories stood at 40.5mm barrels, down 30% on a year earlier. The days' supply at 31.6 was considerably down on the 55.5 of a year earlier and approaching a ten-year low for the time of year.

NET TRADE BALANCE

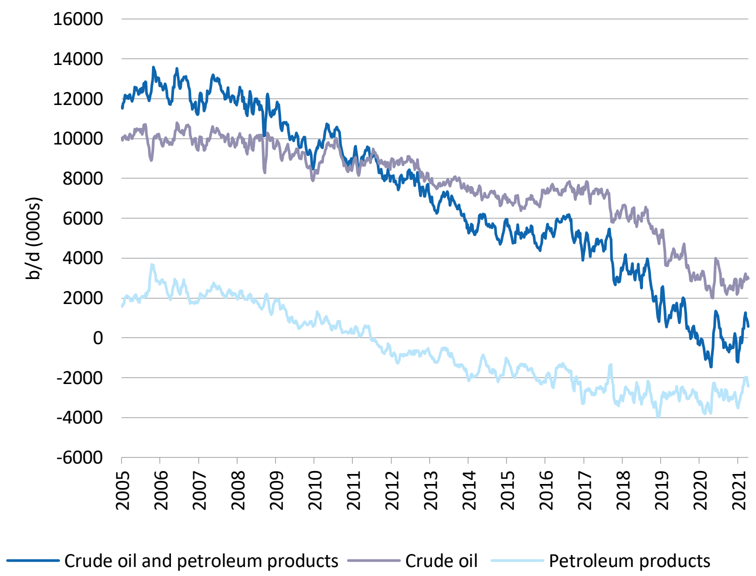
First al encompassing surplus in at least 60 years in 2020: The US managed to eke out a net trade surplus on petroleum products, including crude oil, in 2020 for the first time in, we believe, at least 60 years. Based on EIA data, the surplus was 0.65mm b/d which compared with a deficit of 0.67mm b/d in 2019 and one of 13.5mm b/d at the highwater mark in 2005. The surplus in 2020 comprised a deficit on crude oil of 2.70mm b/d and a surplus on refined product of 3.35mm b/d. The sharp swing on trade from deficit to surplus over the past 15 or so years was largely driven by the following:

- The surge in US domestic crude oil and NGL production since the late 2000s
- The removal in late 2015 of the longstanding embargo on US crude exports. Post 1975 exports had only been allowed to Canada.
- A push, particularly by Gulf Coast refineries, into export markets.
- The competitive cost structure of US Gulf refineries reflecting the availability of cost-advantaged feedstock and refinery fuel plus high utilisation at large scale sophisticated facilities. Feedstock advantages reflected a combination of at times wide discounts of US domestic to international crude prices, the ability to process heavy crude grades and the availability of internationally highly competitive supplies of natural gas.
- Deteriorating operating performance and outages in several Latin American countries. The most significant development here has been the atrophying over the past 10-20 years of the once substantial and productive Venezuelan refinery infrastructure. Venezuela's woes have been compounded by the US embargo on petroleum exports and supplies of petroleum industry equipment and consumables.

Surplus likely to prove fleeting: In all likelihood, the swing to petroleum product surplus in the US will prove fleeting. There are several issues to consider. These include potential financial and quite possibly political constraints on oilfield development, high rates of depletion in the tight reservoir basins of the Mid-Continent and a possible strong upturn in petroleum demand in response to major US public policy initiatives to stimulate the economy. Looking at the most recent EIA data there has, in fact, already been a swing back to deficit, albeit modest. Taking the four weeks to April 16, for example, there was a deficit 0.56mm b/d against a surplus of 1.13mm b/d a year earlier. The deficit on crude widened by 0.43mm b/d to 2.98mm b/d while the product surplus narrowed more significantly by 1.25mm b/d to 2.42mm b/d. Note, the US has had net export product surpluses in consecutive years since 2011. Refining has indeed been a great success story for the US petroleum industry over the past ten or more years. Despite the recent slippage, the surplus on refined product remains sizeable. We believe the recent narrowing mainly reflects weakness in key South American markets.

The EIA is forecasting US petroleum trade deficits of 0.32mm b/d in 2021 and 0.14mm b/d in 2022. Between 2020 and 2022 the swing in the overall trade position stems from a widening in the deficit on crude oil. By contrast, the product surplus increases from 3.35mm b/d to 3.93mm b/d.

EXHIBIT 12: NET TRADE BALANCE



Source: EIA. Note: Data are 4-week averages; negative data refer to surpluses

DOMESTIC DEMAND

Demand approaching pre-crisis levels: US domestic petroleum demand sustained an unprecedented decline in 2020. For the year there was a fall of 11% to 18.12mm b/d, an eight-year low. Usually, petroleum demand in a mature economy such as the US does not fluctuate by more than a few percentage points in any given year. Since the 2020 second quarter low, when demand for a while was running at about 14.5 b/d, there has been solid recovery trend. Demand overall is now indeed approaching pre-crisis levels. For the four weeks ended April 16, 2021 it averaged 19.7mm b/d, up 36% on the second quarter low and 31% on a year ago. Compared with a year earlier, demand in the four weeks to April 16 moved as follows:

- Gasoline (45% of demand) +61.5%
- Distillates +15.9%
- Aviation fuel +62.9%
- Fuel oil -18.8%
- Propane/propylene +23.8%
- Other -0.7%

Liquid's demand could increase by 7% plus in 2021: The EIA's scenario for the balance of 2021 calls for petroleum demand to continue trending solidly upward driven by a strong recovery in economic activity, rapidly increasing miles driven and the partial restoration of civil aviation capacity. For 2021 the EIA forecasts US petroleum and other liquids demand at 19.44mm b/d, 7.3% higher than in 2020 and 5.4% under the 2019 all-time high of 20.54mm b/d. The key assumptions behind this forecast are real GDP growth of 5.6%, a 9.2% increase in highway miles driven and an average retail gasoline price across all grades of $2.78/gallon (+25%).

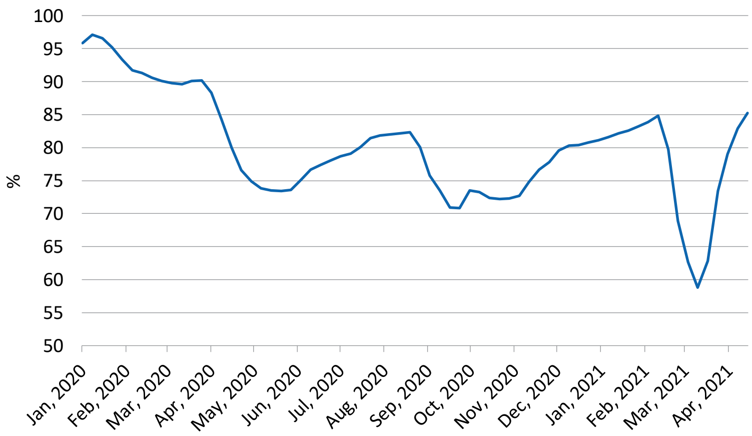
Arguably the risks to the EIA's demand forecast are to the upside given that GDP growth well in excess of 5.6% or even 6% is being predicted in many quarters presently. Against this, the gasoline price forecast could be exceeded bearing in mind that in mid-April 2021 the average for all-grades across the US was about $2.95/gallon. Historically, a gasoline price of around $3/gallon has tended to constitute a psychological barrier for private vehicle users. This phenomenon could once again dampen demand at the margin.

Strong growth to around record levels likely in 2022: The EIA is forecasting petroleum demand growth of 5.0% in 2022. This would take demand to 20.42mm b/d which is very close to the 2019 high. The drivers behind growth in 2022 are expected to be much the same as in 2021. A strong economy and pent-up demand for travel both personal and business are expected to support robust growth. The EIA's key forecast assumptions for 2022 are GDP growth of 4.2%, an average retail gasoline price across all grades of $2.72/gallon and an increase in miles driven of 4.3%. The last mentioned would imply miles driven of only about 1% less than the 2019 all-time high. Assuming that the economy performs robustly near to medium term, as generally expected, it would appear very likely that US petroleum demand will exceed the 2019 high in 2023 at the latest.

REFINERY PERFORMANCE

Gulf Coast refineries operating at 88% utilisation in late April 2021: US refinery financial and operating performance has rebounded powerfully since the second quarter of 2020 when covid-19 restrictions were at their height and product demand was historically deeply depressed. By mid-April 2021 US refinery utilisation was running at 85% having been as low as 68% in the second quarter of 2020. Utilisation rates in the Gulf Coast refineries were hit hard in late February and early March 2021 by severe winter weather but the outages and sub-optimal operating conditions have not been enduring. After having been below 60% in early March, Gulf Coast refinery utilisation had climbed to 88% by late April. Refinery profitability, however, was inevitably impacted in Q1 2021 by outages and low utilisation for about two weeks.

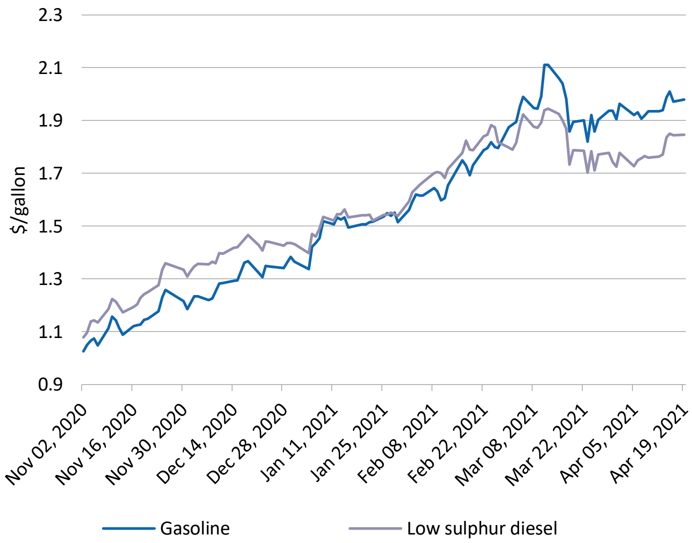
Exhibit 13: US Gulf Coast refinery utilisation



Source: EIA. Note: Data are 4-week averages.

Gasoline prices have surged in recent months boosting crack spreads: The key development for US refineries over recent months has been the surge in gasoline prices. Taking a Gulf Coast refinery as a benchmark, regional wholesale regular gasoline prices have risen 93% to $1.98/gallon between early November 2020 and late April 2021. Gasoline is now trading around a two-year high. By comparison, over the past six months WTI has risen by about 71% while low sulphur diesel is up around 73%. The upshot of the price developments in recent months has been a sharp widening in crack spreads. The Gulf Coast WTI 321 spread (gross margin on converting 3 barrels of WTI into 2 barrels of gasoline and one barrel of diesel) was running at about $7/barrel in early November 2020 but around $19/barrel in late April 2021. Historically, a 321crack spread of this magnitude has been associated with very comfortable levels of fully accounted profitability.

EXHIBIT 14: GULF COAST SPOT GASOLINE & DIESEL PRICES



Source: EIA. Prices are spot wholesale along the Gulf Coast

PRESIDENT BIDEN'S AMERICAN JOBS PLAN

About half American Jobs Plan is conventional infrastructural spending: President Biden announced on March 31, 2021 a $2tr American Jobs Plan to be implemented over eight years. The Plan draws in part from the Green New Deal promoted by a group of left-wing Democrats before the November 2020 election. Roughly half of the Plan relates to conventional infrastructural spending to repair and upgrade highways, bridges, airports, ports, public transit systems and water supply and storm water systems.

The other half of the Plan is directed to climate and decarbonisation issues in tune with achieving a net zero carbon dioxide objective by 2050 and to make electricity generation in the US carbon-free by 2035. Key proposals include providing tax credits and subsidies for the provision of so-called clean energy, electric vehicles and vehicle charging stations. The Biden Plan also calls for substantial sums to be spent on scientific research much of which will be devoted to the climate field and a clean-electricity generation standard that will be made increasingly stringent.

No carbon tax yet: Significantly, the American Jobs Plan does not include a carbon tax which has been advocated by business groups, including some in the energy sector. Rather than attempting to eliminate carbon emissions through the price mechanism the Biden Plan emphasises directly controlling emissions and fuel consumption via legislating standards. This approach has been applied in the auto industry since the 1970s.

Largest infrastructural programme since the Interstate Highway system -----The American Jobs Plan, although much smaller in scope than the Green New Deal, nevertheless constitutes a major infrastructural spending programme. Indeed, we believe it is probably the largest such programme since the construction of the Interstate Highway System in the 1950/60s. Spending of $2/tr over eight years would be equivalent to about 1.2% or $250bn of US GDP/year with the conventional infrastructural element representing about half.

------likely to boost hydrocarbons usage perceptibly: Importantly, from a petroleum and hydrocarbons perspective, the level of planned spending will have a perceptible impact on consumption doubtless to the consternation of Joe Biden. Product wise the key beneficiary would be diesel used to fuel a wide range of earth moving machinery, on and off highway trucks, compressors and off-grid power generation equipment (gen-sets). In addition, substantial quantities of asphalt, cement aggregates and steel will be required. All these commodities are carbon intensive. The American Jobs Plan could unleash the ‘revenge’ of conventional energy.

Lag before higher infrastructural spending impacts the economy: Given the scale and scope of the American Jobs Plan along with the financing implications, implementation is unlikely anytime soon. Significantly, not all Democrats are happy about the Plan. Particularly concerned are those with coal mining and oil and gas constituencies. The Republicans have grave concerns about financing along with major ideological objections to some aspects of the Plan such as subsidies for electric vehicles. It should be remembered that in the Senate the Democrats only have a majority of one by virtue of the Vice President while in the House of Representatives the Democrats majority is seven, a relatively tight situation in a chamber of 435. Horse trading on a prospective American Jobs Plan bill is probably inevitable, although we would expect planned spending on conventional infrastructure to remain largely intact. We think that spending relating to the American Jobs Plan will only become apparent in 2023 at the earliest reflecting both the legislative and planning lead times.

SUPPLY-DEMAND BALANCE

2020

The year in retrospect

Hefty surpluses in H1 2020----The petroleum market swung dramatically from deficit to surplus between the fourth quarter of 2019 and the first half of 2020. Based on EIA data, a deficit of 0.05mm b/d in the fourth quarter of 2019 was followed by surpluses of 5.48mm b/d and 7.70mm b/d in the first and second quarters of 2020, respectively. The swing from deficit to surplus was unprecedented and reflected the collapse in demand with the onset of the covid crisis and the lagged response of supply. During the first quarter production was, in fact, running at near record levels while demand softened noticeably in the second half of the period. Early in the second quarter of 2020 demand was off around an unprecedented 30% year-on-year.

-------were followed by deficits in H2: In the second half of 2020 the oil market swung sharply back to deficit. According to the EIA, there were deficits of 2.26mm b/d and 2.51 mm b/d in the third and fourth quarters respectively. The swing reflected action by both the OPEC and non-OPEC worlds to sharply cut output at a time when demand, driven by China and the US, was firming. Particularly significant in terms of cutting supply were the OPEC+ accord, a drastic cutback in drilling and completion activity in US tight reservoir basins and scaled back operations in the Alberta oil sands. Despite the second half swing to deficit, the market still showed a sizeable surplus of 2.07mm b/d on average for 2020. This was the largest surplus in at least 25 years. The previous high was 1.74mm b/d in 1998 at the time of the Asian Financial Crisis. According to the EIA, global demand in 2020 was off by 8.9% from a year earlier while production was down by a lesser but still substantial 6.2%.

EXHIBIT 15: GLOBAL OIL SUPPLY/DEMAND BALANCE

Mm b/d	**2017**	**2018**	**2019**	**2020e**	**2021e**	**2022e**	**2023e**
Global consumption	98.94	100.05	101.19	92.17	97.67	101.32	104.66
Non-OPEC oil production	61.31	64.10	66.01	63.67	64.85	67.78	69.08
OPEC NGL production	5.30	5.31	5.36	4.98	5.16	5.31	5.52
OPEC crude call	32.33	30.64	29.82	23.52	27.66	28.23	30.06
OPEC crude production	31.54	31.44	29.27	25.59	26.67	28.03	30.03
Surplus/(deficit)	-0.79	0.80	-0.55	2.07	-0.99	-0.20	-0.03
Global production	98.14	100.85	100.64	94.24	96.68	101.12	104.63
Non-OPEC share of global production %	62.5	63.6	65.6	67.6	67.1	67.0	66.0
YOY changes %							
Global consumption	2.2	1.1	1.1	-8.9	6.0	3.7	3.3
Non-OPEC crude production	1.3	4.6	3.0	-3.5	1.9	4.5	1.9
OPEC crude production	-0.4	-0.3	-6.9	-12.6	4.2	5.1	6.7
Global oil production	0.7	2.8	-0.2	-6.4	2.6	4.6	3.5
YOY changes mmb/d							
Global consumption	2.15	1.11	1.14	-9.02	5.50	3.65	3.34
Non-OPEC crude production	0.78	2.79	1.91	-2.34	1.18	2.93	1.30
OPEC crude production	-0.12	-0.10	-2.17	-3.68	1.08	1.36	2.00
OPEC NGL production	0.05	0.01	0.05	-0.38	0.18	0.15	0.21
Global oil production	0.70	2.71	-0.21	-6.40	2.44	4.44	3.51
GDP growth % (real)							
World	3.7	3.5	2.8	-3.5	6.2	4.5	4.1
OECD	2.7	2.3	1.6	-4.7	5.1	3.6	3.3
Non-OECD	4.6	4.5	3.7	-2.3	6.9	5.1	4.8
USA	2.3	3.0	2.2	-3.5	5.6	4.2	3.5

Source: EIA and Allenby Capital.

2021

Sizeable deficits in Q1 and Q2 followed by a sharply narrowing trend in Q3 and Q4: We believe the petroleum market is likely to track between balance and a moderate deficit through 2021 and 2022. Demand growth, in our view, will be historically strong while at least in 2021 supply will respond with a lag. Based on the EIA's April Short Term Energy Outlook, supply deficits of 0.99mm b/d are expected in 2021 and 0.20mm b/d in 2022. In the former the EIA is looking for a quarterly scenario as follows: a deficit of a seasonally high 2.07mm b/d in the first quarter followed by a sharp narrowing in the second, third and fourth quarters to 1.46mm b/d, 0.09mm b/d and 0.34mm b/d respectively.

Q1 and Q2 deficits reflect recovering demand and supply constraints imposed by OPEC+: Hefty supply deficits in the first and second quarters of 2021 are a consequence of two underlying developments. The first is a rapidly strengthening world economy with the key factors being a continuing robust performance by China and a marked recovery in the US. This translates into buoyant petroleum demand growth remembering that these two countries account for about 36% of the world total. The second key driver behind the deficits in the first two quarters is supply constraints. This to a large extent reflects the discipline of the OPEC+ alliance and its de-facto leader Saudi Arabia in restraining output in the first quarter. The disciplined approach kept about 8mm b/d off the market. In addition, extreme weather conditions trimmed output in Texas in February.

Supply constraints should start to ease in Q1 demand likely to be growing strongly: Post the first quarter of 2021 supply constraints should ease while demand remains strong. The upshot is narrowing supply deficits through the fourth quarter of 2021. Strong demand growth over the balance of 2021 is a function of the bullish outlook for the world economy. Consensus forecasts such as used by the EIA suggest economic growth globally in 2021 of about 6% globally. The EIA believes that this is consistent with a gain in petroleum demand of a similar amount.

Demand growth in 2021 expected to be the fastest in years: This is the fastest pace in years, although admittedly coming off a depressed base in 2020. It should be noted here that petroleum demand will receive an additional boost in the US and a few other places from greater personal mobility as covid-related restrictions are either relaxed or removed. This is not strictly an economic issue but rather an administrative/medical one. The successful vaccine roll-out in the US and in some other jurisdictions such as the UK will clearly stimulate both personal and business travel along with energy consumption.

Petroleum supply constraints should ease post the first quarter of 2021. We see three key factors as follows:

- The decision of the OPEC+ alliance to start reversing earlier production cutbacks from May. The current plan is for the alliance to add production of 0.35mm b/d in May, 0.35mm b/d in June and 0.45mm b/d in July.
- The scheduled expiry from May 1 of Saudi Arabia's earlier voluntary 1mm b/d cutback.
- A likely upward trend in non-OPEC output over the balance of the year reflecting positive demand and price trends and development activity. In the vanguard of this tendency, we think will be US and Brazil. Brazilian offshore development activity in pre-salt fields will remain at a buoyant clip as two major projects come on-stream in the second half of 2021. For the year as a whole, the EIA is looking for a gain in Brazil of 0.38mm b/d or 10%. Following resolution of technical issues with a gas compressor on an FPSO (floating, production, storage and offloading), production from ExxonMobil's Liza field offshore Guyana should regain upward momentum in the coming months back to 0.11-0.12mm b/d.

Higher Iranian exports could buoy supply over balance of 2021 in contravention of sanctions: Another factor potentially buoying supply in the coming months could be rising Iranian output and exports. Since 2018, Iran has been under US sanctions which theoretically embargo exports. Iran's output has, however, been increasing of late while shipments regardless of sanctions are being made to China. According to a recent Refinitiv report, Iranian exports to China averaged 0.56mm b/d between November 2020 and March 2021. The Iranian oil sells at a discount of $6-7/barrel to Angolan and Brazilian light grades. Sanctions on Iran could be lifted in due course assuming a new agreement with the US concerning nuclear non-proliferation and possibly other issues. The consensus is, however, that negotiating such an agreement will be an arduous and lengthy process and may not happen this year. Historically, Iranian exports of crude have been around 2.0mm b/d.

In summary the EIA's key oil market forecasts for 2021, which we see as plausible, are as follows:

- Global demand growth 5.50mm b/d, 6.0%
- Global production growth 2.44mm b/d, 2.6%
- Non-OPEC production growth 1.18mm b/d, 1.9%
- OPEC crude production growth 1.08mm b/d, 4.2%
- NGL production growth 0.18mm b/d, 3.6%

Global oil demand in 2021 on the above basis would be 97.7mm b/d, down 3.5% on the all-time peak in 2019. By comparison, global production would show a shortfall of 3.9%.

2022

EIA forecasting a modest deficit of 0.20mm b/d and record output: We expect global demand growth to remain strong historically in 2022 but to be somewhat slower than in 2021 as the year-on-year comparison becomes tougher. The EIA's forecast of a modest supply deficit of 0.20mm b/d reflects demand growth of 3.7% and a 4.6% gain in production. This scenario would take global production and demand to 101.3mm b/d and 101.1mm b/d respectively, both slightly higher than the 2019 levels. Interestingly, several observers, including BP, had suggested a year or so ago that petroleum demand may have peaked in 2019.

Demand driven by robust economic growth and the relaxation of covid restrictions: Demand in 2022 should continue to be buoyed by robust economic growth globally and hopefully the continuing relaxation or removal of covid-related restrictions on personal mobility. Assuming successful covid-19 vaccine regimes, most elements of travel should largely return to normal in 2022. The EIA's petroleum demand forecasts assume world economic growth of 4.5% which we believe looks plausible given the powerful monetary and fiscal stimuli in place around the globe and pent-up consumer demand. As discussed in the US section, it is also possible that in 2022 that energy intensive infrastructural fiscal spending could start filtering through to GDP growth.

Forecast petroleum demand growth in 2022 of 3.65mm b/d appears sizeable by historical standards but production capacity should be sufficient. This reflects the following:

- At the end of 2021 there will still probably be significant spare capacity within OPEC, particularly if sanctions are relaxed or removed on Iran and Libya continues to reinstate capacity
- Expansion projects are scheduled to come on-stream especially in Brazil, Guyana and possibly Russia.
- The potential to raise utilisation in the Alberta oil sands given earlier curtailment actions.

- Rising drilling activity in the tight reservoir basins of the US Mid-Continent and Texas. Note, this is a short lead time operation with a lag of perhaps six months or so between a decision to drill and production assuming suitable acreage and competent well planning.

Rapid OPEC and non-OPEC output growth: The EIA is forecasting for 2022 growth in OPEC and non-OPEC production of 1.51 mm b/d and 2.93 mm b/d respectively. Based on the EIA scenario, non-OPEC output would be running at record levels in 2022 of 67.8mm b/d. OPEC crude output at 28.0mm b/d would however still significantly lag the peak in recent years of 31.7mm b/d. It should be noted that in recent years that OPEC output has not only been curbed by policy decisions but also by sanctions and degraded infrastructure in Venezuela, the sanctions regime against Iran and disrupted output due to civil war in Libya.

2023

Approximate market balance: We have taken an initial look at how the oil market might appear in 2023. Tentatively we see the market being in approximate balance. Demand is expected to continue trending upward courtesy of the backwash of stimulatory fiscal and monetary policies in the OECD world and China which we would see driving world GDP growth by around 4%. In these circumstances, we believe oil demand might increase by an historically high 3.3% to 104.7mm b/d, thereby comfortably exceeding the 2019 high of 101.2mm b/d.

Irresistible temptation for OPEC to boost output: We think with a robust economic and demand backdrop OPEC will find it impossible to resist the temptation to boost production after several lean years. This could be in the region of 2mm b/d which would take OPEC crude output to about 30mm b/d for the first time since 2018. Implicitly we are assuming here a return in Iranian exports to at least 1.5mm b/d. We believe this will be achieved either covertly with no reaction from the US or as a part of a grand rapprochement with the US.

Non-OPEC output to be boosted by development activity in US, Brazil and Guyana: Assuming a bullish market backdrop quite possibly with prices comfortably above fully accounted breakeven, we would look for non-OPEC output to climb strongly from a historical perspective in 2023. A gain of 1.3mm b/d is forecast. We see this as being underpinned largely by offshore field development particularly in Brazil and Guyana, stepped-up drilling activity in the tight reservoir basins of the US, new development projects coming on-stream in the Gulf of Mexico and development activity in Russia. Because non-OPEC producers typically operate at high utilisation rates, we see the scope for output gains being significantly higher within OPEC, where there is surplus capacity, than outside OPEC.

PROSPECTS FOR A SUPER-CYCLE

Goldman is a proponent of the super cycle-----: Recently some commentators, notably Goldman Sachs, have speculated on the prospects for a new super-cycle for oil and commodities in general. A super cycle might be defined as a sustained period of historically high demand caused by a structural change in the world economy, a technological change or a socio/political development. Typically, a super-cycle would be characterised by tight supply-demand balances and prices rising in real terms. In the case of oil, a key example of a super-cycle was in the 1960s and early 1970s when demand was growing powerfully for the commodity driven by positive macro-economic trends and the motorisation of the world. This culminated in the price surge of the mid to late 1970s. Another example is the upward trend in oil prices from the early 2000s to mid- 2008. The catalyst here was the rise of China as a major industrial power at a time of supply constraints. The cycle was brought to a close by the US shale revolution of the post 2010 period.

------reflecting public policy emphasis on infrastructural spending: Goldman's thesis is that the current public policy emphasis on infrastructure expansion and upgrading for technological advances will require a substantial input of hydrocarbon-based fuels, particularly diesel. Whether this will result in a super-cycle, pushing demand to a higher level sustained over perhaps a decade or more, rather than merely providing a modest boost over a shorter period is an open question.

Infrastructural spending although significant unlikely to be powerful enough to trigger a super cycle: We err to the latter view. Although of fundamental importance, we think that infrastructural spending is unlikely to have the same impact on petroleum demand as, for example, the motorisation of the western world between the 1950s and 1970s and mass air travel a little later. We also believe that for petroleum producers with long-life assets substantially higher prices over a sustained period are a mixed blessing given the potential for substitution by new technologies. Effectively, high real prices combined with other factors such as public policy measures to control emissions would lower the bar for substitution. This could potentially translate into the phenomenon of stranded assets. In the event of sustained historically high oil prices, we believe OPEC combined with short cycle non-OPEC shale producers, would also respond quickly to raise output.

Industrial metals are likely to be the major beneficiary of higher infrastructural spending: Although a new oil super-cycle appears unlikely or indeed implausible, we believe there is a case for the concept for industrial metals. Infrastructure spending is metals intensive and the transition from hydrocarbon intensive energy to renewable energy sources and electrical power point to a massive increase in the use of a range metals such as nickel, cobalt, lithium, manganese, vanadium, copper, aluminium and rare earths. Substantial amounts of iron-ore and coking coal will also be needed. It is one reason to suggest that the 2050 net zero carbon target is overly ambitious. A reality check is needed.

POTENTIAL SECULAR DECLINE IN EXPLORATION EXPENDITURE

The UN net zero GHG target implies declining hydrocarbons exploration activity: Public policy measures to achieve compliance with the United Nations net zero greenhouse gas emissions (of which CO_2 is the most important) objective by 2050 logically implies declining exploration activity for hydrocarbons. The objective necessitates either not releasing the emissions into the atmosphere in the first place or matching emissions with carbon capture and sequestration (CCS).

Exploration activity at the beginning of a secular decline: In reality, exploration activity is already being cutback and the trend is likely to gather pace as the decade advances. Major oil companies, notably BP and Shell, have suggested that they are seeking a 40% drop in oil production with a large part of this achieved by declining upstream investment and depletion rather than divestments. Exploration related headcount is being downsized. Interestingly, the Norwegian major, Equinor, has suggested that its objective is not only to be net zero in terms of operations but also for the emissions resulting from the oil it produces, the so-called scope 3 emissions. Unlike their European peers, the US and Canadian majors have so far expressed no enthusiasm for cutting back upstream exploration activity. Rather, they have emphasised carbon capture and sequestration plus in the case of ExxonMobil bio-fuel development.

Impact of declining exploration activity and depletion will become increasingly apparent post mid-2020s. Although we do not believe falling petroleum supply is an issue near-term, we think increasing rates of depletion could start becoming apparent post the mid-2020s among non-OPEC producers at least. Presumably, with falling exploration outlays the trend would accelerate noticeably post 2030. The question then arises to what extent the void will be filled by OPEC producers and Russia. Theoretically both would be expected to be compliant with the UN Paris Agreement to cut GHG (greenhouse gas) emissions but it is difficult, if not impossible to see either abandoning their oil and gas industries. Given the availability of reserves particularly in OPEC and the danger of stranded assets, it must be assumed that the void would be filled. OPEC's share of the world oil market could therefore start trending noticeably higher in the second half of the 2020s thereby reversing the declining trend that has been apparent over the past 10 years as non-OPEC output has grown apace.

Potential for a medium-term tightening in supply/demand balance: The above trends in supply could imply a tightening supply-demand balance medium to long term and rising real prices. The extent that this occurs will depend on both the price elasticity of demand and the effectiveness of public policy measures to enhance fuel efficiency and discourage the use of petroleum products.

CRUDE OIL PRICE OUTLOOK

MARKET THESIS AND PRICE FORECASTS

2021

Market tightened sharply between Q4 2020 and Q1 2021: The oil market tightened sharply between the fourth quarter of 2020 and the first quarter of 2021. This was driven by strengthening demand, particularly in the US, at a time when supplies were constrained largely as a result of the OPEC+accord. A contributory factor was the impact of severe weather in the US and a generally slow non-OPEC supply response. This combination of events broadly returned benchmark light crude prices by mid-March 2021 to the levels prevailing in early January 2020. Given the upward trajectory in prices during the first quarter, there was significant positive carryover going into the second quarter of 2021. Through late April the price trend remained firm with Brent, for example, still relatively close to the recent March closing high of $69.6/barrel.

Upward trend in prices over balance of 2021 but several factors likely to constrain the advance: We believe the market backdrop will be conducive to a continuing upward trend in light crude prices over the balance of 2021. The market is likely to remain in deficit, in our view, albeit to a lesser extent than in the fourth quarter of 2020 and the first quarter of 2021. This reflects strong growth in demand unmatched by supply as the covid-19 crisis eases in the OECD world at least and the Chinese economy continues to perform robustly. Keeping a lid on prices through 2021 year end we believe will be three factors as follows:

- A narrowing supply deficit and the threat of an influx of OPEC and possibly US shale supply should prices look like breeching $70/barrel, a clearly highly profitable level for virtually all producers.
- Still sizeable inventories.
- Occasional flare-ups in the covid-19 pandemic in various parts of the world.

Brent average 2021 forecast $66.1/barrel: Brent averaged $60.8/barrel in the first quarter of 2021 and in late April was trading around $66/barrel or slightly below the recent highs of mid-March. Given the above backdrop, we look for Brent to average $66.5/barrel in the second quarter of 2021in line with recent levels. Near term, we believe the upward trend could be dampened by the current upsurge in covid cases in several parts of the world with India and Brazil particularly notable. Over the last two quarters of 2021 we forecast a renewed strengthening trend with Brent averaging $70/barrel in the fourth quarter. Based on our scenario, Brent would average $66.1/barrel, the highest yearly average since the $71.2/barrel of 2018.

WTI average 2021 forecast $62.7/barrel: WTI averaged $57.8/barrel in the first quarter of 2021 and in late April was trading at around $62/barrel or about $4/barrel below the highs of early to mid-March. After averaging $3/barrel in the first quarter the Brent-WTI spread has widened of late to closer to $4/barrel. It however remains within the range of the past 18 months or so. Assuming a Brent-WTI spread of $3.5/barrel, which we believe is broadly in line with pipeline fees from Cushing to the Gulf Coast, we look for WTI to average $63.0/barrel, $63.5/barrel and $66.5/barrel in the second, third and fourth quarters of 2021, respectively. The average for 2021 would be $62.7/barrel, a post 2018 high.

2022/2023

Forecast 2022 price peak----: We look for benchmark light crude prices to peak in the current cycle in the first quarter of 2022. Global oil demand, we believe, will still be growing rapidly in early 2022. This reflects the expected ongoing recovery in the world economy from the corona virus crisis possibly with some added impetus from public sector financed infrastructure spending and upturn in business investment. We believe, however, that as benchmark light crude prices approach or exceed $70/barrel supply, particularly from OPEC, will be sucked into the market. As a result, the market is likely to return to approximate balance by early 2022.

------at $73.0/barrel for Brent and $69.5/barrel for WTI: We look to the above resulting in Brent and WTI averaging $73.0/barrel and $69.5/barrel respectively in the first quarter of 2022. This, however, is expected to give way to a softening trend over the balance of 2022 and into 2023 reflecting a supply influx and a return to approximate balance in the marketplace. By the fourth quarter of 2022 we expect Brent to average approximately $67.0/barrel. For 2022 as a whole, we forecast Brent to average $69.3/barrel. Our forecast for WTI in 2022 is $65.9/barrel, a discount of $3.4/barrel to Brent.

Dampening supply influence: In 2023 we look for a flat to down trend in benchmark light crude prices. We believe the demand backdrop should still be buoyant but see supply growth acting as a dampening influence. Brent and WTI in 2021 are forecast to average $66.3/barrel and $62.8/barrel, respectively.

WILD CARDS AND COMMODITY PRICE RISK

Direction of the coronavirus crisis is the key area of uncertainty: The key near term wild card and area of uncertainty for the petroleum market and indeed the wider economy concerns the direction of the coronavirus crisis. The nub of the issue relates to the efficacy and speed of application of the vaccines developed. Only with the rapid roll-out of vaccines will successive waves of infection and periodic health and economic crises be prevented. Recently several hot spots have surfaced in Asia, Latin America and indeed in parts of Europe and North America. A recurrence on a regular basis of waves of infection followed by restrictions on economic activity and personal mobility would clearly be damaging for the world economy and hence oil consumption.

Herd immunity broadly requires at least 80% of the population to be inoculated, according to expert opinion. While the scientific data is highly encouraging on vaccine efficacy few if any countries have sufficient people inoculated to have established herd immunity. Furthermore, to fully restore transportation links inoculations need to be undertaken globally. While herd immunity through vaccination is a distinct possibility in much of the OECD by end 2021 this is not the case in large tracts of the rest of the world. The restoration of international travel is therefore unlikely until deep into 2022 at the earliest. This points to a constraint on oil usage in long haul aviation and related sectors for some time to come.

Improved covid-19 therapeutics could provide a positive surprise: A positive surprise on the coronavirus front would be a breakthrough on the therapeutics front. There is already one apparently efficacious product available produced by the US pharmaceutical company Regeneron (NASDAQ: REGN). It is, however, relatively expensive and needs, we believe, to be administered during hospitalization. Other products are under development. A combination of potent vaccines and therapeutics administered in tablet form at home would mean an end to the corona virus crisis. Travel and the petroleum industry would be major beneficiaries.

Outside the corona virus crisis, we see the key wild cards as follows:

- Does the US 10-year Treasury bond yield trend upwards over the balance of 2022 to 2% plus or does it stay within the recent range of 1.50-1.70%. Given the potential for higher inflation and the massive financing needs of the federal government the former scenario would appear plausible. Through the link to credit markets the economic outlook for 2022 might be less robust than the bullish consensus suggests.

- The reaction of the OPEC+ alliance to a partial reversal of the earlier cutback programme. The key issue is do the members, including Russia, comply with the measured policy of relaxation or do they step-up production more aggressively.

Practically all members of the alliance have pressing budgetary issues and all can generate excellent margins at $60-70/barrel Brent.

- The status of US sanctions on Iran. As expected, the US under a Biden presidency has re-joined the P5+1 (five members of the UN Security Council plus Germany) Iran nuclear non-proliferation talks. According to press reports, the negotiations are making progress. Any agreement will require existing US sanctions on Iran to be withdrawn. This could theoretically unleash around 1.5mm b/d to 2mm b/d of oil production onto the market in the absence of cutbacks elsewhere. It should be noted however that Iran and China are already breaching the sanctions so the impact might be less than the theoretical position.

- The status of the Maduro regime in Venezuela. Does President Maduro continue to persevere with the support of Russia producing about 0.5mm b/d of oil or does the regime collapse over the next year or two. If it does, this would usher in a period of significantly higher production. Note, unless there is a rapprochement with the US Venezuela is likely to be confronted in the coming years with the issue of stranded assets. The country has the largest petroleum reserves in the world and is therefore potentially imperilled by decarbonisation measures.

- The policy stance of US producers in the Lower 48 states to rising prices. Do they pursue higher production or prioritise cash flow and debt reduction as has been suggested in company announcements? With the rig-count firming the evidence suggests a two-pronged approach.

- The impact of the coronavirus epidemic in Brazil on offshore oilfield development in the Santos Basin. So far oilfield development in Brazil has been little if at all affected by the epidemic. As a result, production has grown apace. With the epidemic now reaching crisis proportions whether the pace of development can be maintained in the short-term is an open question. A cessation of development activity in Brazil would have a material impact on the global supply/demand balance and in the process buoy oil prices globally.

- The potential for slower than consensus GDP growth in 2021 and possibly 2022 due to the global shortage of semiconductors. This problem appears to be growing by the day and is not just impacting automotive. While not likely to derail the economy completely shortages of semiconductors and indeed other components and commodities could leave the more bullish global GDP growth forecasts for 2021/22 vulnerable.

- Climate change issues and the associated political response. Will carbon taxation be widely adopted? So far Joe Biden has notably avoided the issue of a carbon tax but Prime Minister Justin Trudeau has introduced one in Canada. For those seeking to reduce the use of hydrocarbons a carbon tax ratcheted upwards on an annual basis is arguably the simplest and most effective mechanism for doing so. The widespread adoption of carbon taxes must be considered a distinct possibility over the next few years. Carbon taxes may simply be hiked until demand for hydrocarbons is simply choked off regardless of the impact on economic activity.

- The details of US energy and environmental policy under a Biden Presidency. He has already shown his hand with embargoing or obstructing pipeline development, banning drilling on federal land and proposing to make changes to the tax code to disadvantage oil and gas producers. A series of incremental legal and regulatory moves could be implemented all of which will raise the cost of oil and gas development. Although officially out of bounds, President Biden may yet decide to ban high-pressure fracking in specified circumstances.

- Developments on the rechargeable battery technology front. The key potential development is progress on solid-state technology which would enable the liquid electrolyte between the anode and cathode to be replaced by a solid material. This could result in a radical improvement in energy intensity resulting in major gains in power, range, recharging times and safety (liquid electrolytes are flammable). Several auto OEMs such as BMW, VW and Toyota have recently indicated that they stepping-up development work on solid-state technology. They know that without the advances in battery performance achievable with solid-state that EVs will remain a tough sell for many applications. The general thinking is that solid-state technology is not likely to be available commercially much before 2030. Any indication of an earlier introduction would be a clear negative for auto-related petroleum usage.

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

	Q1	Q2	Q3	Q4	Average
2009	44.5	58.9	68.1	74.6	61.5
2010	76.4	78.5	76.8	86.6	79.6
2011	105.5	117.2	113.2	109.4	111.3
2012	118.6	108.3	109.6	110.2	111.7
2013	112.4	102.6	110.2	109.2	108.6
2014	108.1	109.7	101.9	76.4	99.0
2015	53.9	61.6	50.4	43.6	52.4
2016	33.9	45.6	45.8	49.3	43.7
2017	53.6	49.5	52.1	61.4	54.2
2018	66.9	74.5	75.0	68.3	71.2
2019	63.1	69	61.9	63.3	64.3
2020	50.0	29.5	43.0	44.3	41.7
2021e	60.8	66.5	67.0	70.0	66.1
2022e	73.0	70.0	67.0	67.0	69.3
2023e	67.0	66.0	66.0	66.0	66.3

Source: EIA and Allenby Capital

EXHIBIT 17: WTI 2009-2022 QUARTERLY PRICES ($/BBL)

	Q1	Q2	Q3	Q4	Average
2009	43.2	59.7	68.1	76.0	61.8
2010	78.8	77.9	76.1	85.2	79.5
2011	93.9	102.3	89.5	94.0	94.9
2012	103.0	93.3	92.2	88.2	94.2
2013	94.3	94.1	105.8	97.6	98.0
2014	98.7	103.1	97.6	73.2	93.2
2015	48.5	57.9	46.4	41.9	48.7
2016	33.2	45.4	44.9	49.1	43.2
2017	51.8	48.2	48.2	55.4	50.9
2018	62.9	68.1	69.7	59.6	65.1
2019	54.8	59.9	56.4	56.8	57.0
2020e	45.3	28.0	40.9	42.5	39.2
2021e	57.8	63.0	63.5	66.5	62.7
2022e	69.5	67.0	63.5	63.5	65.9
2023e	63.5	62.5	62.5	62.5	62.8

Source: EIA and Allenby Capital

EXHIBIT 18: BRENT AND WTI LONG-TERM PRICE TRENDS

$/bbl	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020e	2021e	2022e	2023e
Brent	61.5	79.6	111.3	111.7	108.6	99.0	52.4	43.7	54.2	71.2	64.3	41.7	66.1	69.3	66.3
WTI	61.8	79.5	94.9	94.2	98.0	93.2	48.7	43.2	50.9	65.1	57.0	39.2	62.7	65.9	62.8

Source: EIA & Allenby Capital

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