NATURAL RESOURCES

November 2019

OIL & GAS

OIL & GAS MACRO OUTLOOK

Flat near-term pricing outlook

Light oil prices came under heavy pressure in Q3 2019 and have subsequently stabilised at the lower levels. The downward pressure was despite the market moving into significant deficit driven in part by the Saudi Aramco outage following the attack on key facilities, which for a short period reduced world oil output by 5%. The market was prepared to overlook the attack, given the lack of military response and impressively expeditious repair work. Bearish sentiment has reflected the increasingly lacklustre macro-economic backdrop in both the OECD and non-OECD worlds which is dampening demand growth. We expect prices to trend broadly flat in the coming months with Brent and WTI at about $59/barrel and $54/barrel respectively. This reflects our view that the market will be in approximate balance. We expect lacklustre demand to be largely offset by continuing OPEC production restraint. Our expectation is that the existing OPEC+ production accord will, at least, be carried over at the next meeting in November.

- **Supply/demand balance**: According to the EIA's October report, the oil market globally was in deficit to the tune of 0.85mm b/d in Q3 2019 which more than offset the first half surplus of 0.54mm b/d. The EIA's Q4 forecast is 0.28mm b/d implying approximate balance for 2019. This compares with our forecast of a surplus of 0.14mm b/d previously. For 2020 we look for a surplus of 0.29mm b/d, down on our previous forecast of 0.43mm b/d.

- **Oil production:** Non-OPEC production growth in 2019 has remained strong, although slower than in 2018. The EIA is looking for growth of 2.07mm b/d for 2019 driven by the US and to a lesser extent Brazil. Our forecast for non-OPEC production in 2020 calls for growth of 1.94mm b/d, slightly down on our May 2019 forecast of 2.00mm b/d. The US and Brazil will continue to be the key drivers, although growth in the case of the former is likely to be lower than in 2018/19. Offshore Guyana will make a first-time contribution in 2020. OPEC production has fallen significantly in 2019 reflecting the Saudi outage and US sanctions on Iran and Venezuela. The EIA forecasts a decline in OPEC output of 2.13mm b/d in 2019.

- **Oil demand**: Consensus 2019 petroleum demand growth forecasts have been downgraded as the year has progressed reflecting the world economic slowdown plus in parts of the developing world rising product prices in local currencies. Our forecast for the year of +0.84mm b/d is in line with that of the EIA. For 2020 we look for growth of 1.0mm b/d which is lower than consensus forecasts of 1.1-1.2mm b/d reflecting a more bearish view of the economic backdrop. We believe the risks for petroleum demand in 2020 are to the downside. Our demand forecasts reflect world GDP growth (oil weighted) assumptions of 2.0% in 2019 and 2.2% in 2020. The former is in line with the EIA while the latter is lower.

- **Forward curves**: As of late October, the forward curves for Brent and WTI point to a benign market outlook with no major changes in the supply/demand balance in the coming years. The front-end of the curves remain in backwardation but to a lesser extent than a few months ago. The Brent and WTI spot to early 2022 spreads are around $4/barrel. Post 2022 the curves for both grades switch to mild contango. The terminal value for the Brent curve in early 2028 of $59.2/barrel is in line with the late October 2019 spot price. For WTI the spot to early 2028 spread reflects backwardation of $3/barrel.

- **Price forecasts**: Our Brent and WTI forecasts for 2019 and 2020 have been downgraded. For 2019, Brent is forecast to average $63.4/barrel against $67.4/barrel previously while WTI drops from $60.2/barrel to $56.2/barrel. Our Brent 2020 forecast decreases from $64.1/barrel to $61.5/barrel while WTI declines from $59.3/barrel to $56.3/barrel. The downgrades reflect a weaker than expected trend in 2019 YTD and lower 2020 carryover.

BRENT VS WTI

	1m	3m	12m
Brent $/bbl	-1.6%	-1.3%	-20.8%

Source: EIA

Analyst: Peter J Dupont

Phone: 0203-002-2078

Email: p.dupont@allenbycapital.com

www.allenbycapital.com

Please refer to the last page of this communication for all required disclosures and risk warnings.

EQUITY RESEARCH

This document is a marketing communication which has been produced by Allenby Capital Limited. It is non-independent research and has not been prepared in accordance with legal requirements designed to promote the independence of investment research. Accordingly, Allenby Capital Limited is not subject to any prohibition on dealing ahead of the dissemination of this document.

CONTENTS

EXECUTIVE SUMMARY

Recent price developments: Benchmark light crude prices recovered powerfully in the first half of 2019 from the depressed levels of late 2018. However, they came under heavy pressure late in the second quarter and in the first two months of the third quarter. Since late September the trend has been broadly flat. The recent lows in August were $57.1/barrel for Brent and $51.1/barrel for WTI. Both were comfortably above the late 2018 lows but down about 23% on the April 2019 highs.

The key event in the third quarter of 2019 were the attacks on the Saudi Aramco facilities at Abqaiq and Khurais on September 14. These temporarily reduced Saudi oil output by about 5.7mm b/d or 5% of the world total. In the wake of the attacks, Brent initially surged by 20% to $72/barrel. The surge however proved short-lived. By end September both Brent and WTI were back to pre-attack levels of about $61/barrel and $54/barrel respectively. The absence of a sustained price rise subsequent to the September 14 attacks reflects no military response and expeditious repair work by Aramco.

The weak price trend of recent months has consistent with our expectations but has occurred despite a significant tightening in the marketplace engendered in part by the September 14 attacks on Aramco. The explanation is twofold. Firstly, the market's willingness to look through the attacks on Aramco and secondly a growing preoccupation with a world economic slowdown and a deteriorating petroleum market backdrop. Early in the fourth quarter of 2019 speculation concerning the potential for a new OPEC+ production accord, possibly incorporating a deeper cutback regime than presently existing, has provided some support for prices.

Brent-WTI and other light/sweet spreads: The Brent-WTI spread has narrowed significantly in recent months from the historically high levels of the first half of 2019. In the third quarter this spread averaged $5.5/barrel and in late October 2019 was running around $5.2/barrel. The narrowing trend has been driven by falling inventories at the Cushing Oklahoma tank farm and signs of slower production growth in Texas and the Mid-continent. At least, in part, falling inventories at Cushing have reflected new pipeline capacity linking the Permian Basin directly with the Gulf Coast refineries and export terminals. We believe the Brent-WTI spread will remain narrow by recent historical standards in the fourth quarter of 2019 and in 2020, reflecting the structural changes in pipeline capacity in Texas.

The Permian Basin (WTI Midland) light crude discount to WTI Cushing has largely returned to normal in 2019 reflecting the removal of pipeline bottlenecks. As of late October 2019, the Midland discount was running at about $3.3/barrel. Light crude spreads for the remote basins such as the Williston (North Dakota) have also narrowed from the exceptionally wide levels of about $20/barrel at the end of 2018. In late October 2019 the Williston Sweet discount to WTI Cushing was $10.4/barrel which is within the historical range abstracting from exceptional developments.

Forward curves: The front-end of the forward curves for Brent and WTI remain in backwardation (near month prices higher than for the more distant dates) but to a lesser extent than a few months ago. Post the attacks on the Aramco facilities backwardation was marked but this proved short-lived. Contrasting with earlier in 2019, when the middle and back-end of the Brent and WTI forward curves trended flat, they have now moved into mild contango (near month prices lower than for the more distant dates). Interestingly, the Brent curve for early 2028 shipments of $59.5/barrel was little different than the late October 2019 spot price. The late October 2019 forward curve reflected mild backwardation between spot and early 2028 of $2.3/barrel. Overall, the Brent and WTI forward curves point to a benign market outlook with no major changes in the supply-demand balance in the coming years.

Supply-demand balance: The petroleum market has tightened considerably since the fourth quarter of 2018 when there was a supply surplus of over 2.0mm b/d, according to EIA data. After a surplus of 0.54mm b/d in the first half of 2019 the market apparently swung to a deficit of 0.83mm b/d in the third quarter. The EIA is looking for a modest surplus in the fourth quarter of 0.28mm b/d which would imply approximate balance for 2019 as a whole. This compared with a surplus of 0.83mm b/d in 2018. Previously we had been looking for a surplus in 2019 of 0.14mm b/d.

The tightening trend in 2019 primarily reflects a sharp decline in OPEC output stemming from the November 2018 production accord, the Saudi outage in September and the impact of US sanctions on Iran and Venezuela. Non-OPEC production growth has remained buoyant in 2019 but the pace has slowed compared with 2018. A major market development in 2019 has been significantly slower demand growth than in recent years. An increasingly lacklustre world economy is to blame. For 2020 we look for a modest supply surplus of 0.29mm b/d. Our forecast reflects another year of moderate consumption growth of 1.0mm b/d, a further deceleration in non-OPEC production growth and a decline in OPEC production of about 0.3mm b/d. Slowing non-OPEC production growth, we think, will be driven by the US stemming from the lagged effect of falling drilling and completion activity. We expect OPEC+ production to be subdued in 2020 reflecting, at minimum, an extension to the existing production accord. A new accord incorporating deeper production cutbacks is a possibility. OPEC is scheduled to decide production strategy at its next meeting in late November 2019.

Market thesis: We look for a subdued price trend in the fourth quarter of 2019. This reflects our view that the market will be comfortably supplied over the balance of the year and that the lacklustre economic backdrop will continue to weigh on market sentiment. We believe that Brent and WTI will trade broadly within the third quarter price range, excluding the Saudi-attack related spike in September, of $56-66/barrel and $54-58/barrel respectively. Our Brent and WTI scenario for 2020 calls for a broadly flat trend based on our outlook for a modest supply surplus and a lacklustre macro-economic backdrop globally. A key issue for 2020 is the trend in US production in the light of declining drilling/completion activity and falling well productivity. There is a risk that this will result in production significantly below consensus. Other things being equal, this could result in a tighter market than generally expected and an upside price surprise.

Price forecasts: Our Brent and WTI forecasts for 2019 and 2020 have been downgraded. For 2019 Brent is forecast to average $63.4/barrel against $67.4/barrel previously while WTI drops from $60.2/barrel to $56.2/barrel. Our Brent 2020 forecast decreases from $64.1/barrel to $61.5/barrel while WTI declines from $59.3/barrel to $56.3/barrel. The downgrades reflect a weaker than expected trend through the nine months to September 2019 and the consequent smaller carryover effect going into 2020.

EXHIBIT 1: ENERGY PRICE SUMMARY

	Brent $/bbl	WTI $/bbl	Henry Hub $/mcf
2015	52.4	48.7	2.73
2016	43.7	43.2	2.61
2017	54.3	50.9	3.10
2018	71.2	65.1	3.16
2019e	63.4	56.2	3.25
2020e	61.5	56.3	3.30

Source: EIA, Allenby Capital

CRUDE OIL MARKET DYNAMICS

RECENT MARKET TRENDS AND DEVELOPMENTS

Economic slowdown, strong non-OPEC production trend, attack on Saudi facilities: Since our last report in early May 2019, the oil market has been dominated by three key influences. These are the growing evidence of a lacklustre demand backdrop driven by slowing world economic growth, a continuing strong upward trend in non-OPEC production and an apparent Iranian missile/drone attack on the Saudi Aramco facilities at Abqaiq and Khurais in the Eastern Province on September 14. After the hefty supply surpluses of the third and fourth quarters of 2018 there was a marked narrowing in the first and second quarters of 2019 and a swing to a significant deficit in the third quarter based on EIA data. The third quarter tightening reflected, in part, the outages following the attack on the Aramco facilities which for a short period reduced Saudi oil production by about 5.7mm b/d or 60%. The reduction in world oil production was about 5%. This was more than surplus global capacity before the strike on the Aramco.

Upward trend in prices in H1 2019: Benchmark light crude prices trended noticeably higher in the first half of 2019 from the depressed levels of late 2018. Prices were buoyed by the ratchetting down of the significant supply surplus in the second half of 2018, bullish sentiment relating to the potential tightening effect of US trade and financial sanctions on Iran and Venezuela and the OPEC+ (the plus primarily relates to Russia) production accord.

Prices peaked in April/May well above end 2018 levels: After averaging $63.2/barrel in the first quarter, Brent came in at $68.9/barrel in the second quarter. WTI, the US Mid-continent benchmark averaged $54.8/barrel and $59.8/barrel in the first and second quarters respectively. During the second quarter of 2019 prices peaked in late April and May at around $74/barrel for Brent and $63/barrel for WTI. For comparison, at the end of 2018 Brent was trading at about $51/barrel while WTI was around $45/barrel. Despite the upward trend in the first half of 2019, prices still lagged year earlier levels but nevertheless implied comfortably profitable levels for the bulk of producers.

Marked softening in Q3 2019: Petroleum prices softened markedly in the third quarter of 2019 before the attack on Aramco's facilities at Abqaiq and Khurais on September 14. Indeed, Brent, the international light crude benchmark plumbed an average 2019 monthly low in August of $59.0/barrel. The WTI average for the month was, however, marginally above the June level of $54.7/barrel. The spot closing lows in August 2019 were $57.1/barrel and $51.1/barrel for Brent and WTI respectively.

Slowing world economic growth was the key driver: The weakening price trend through the first two months of the third quarter of 2019 occurred despite an apparently tightening market place and falling US inventories. It appears to have been driven primarily by signs of slowing economic growth and significant downgrades by the IMF and other forecasting agencies to global GDP forecasts for 2019 and 2020. Contributing to the malaise on the macro-economic front, as for other commodity markets, was the intensification of the US-China trade war.

Prices surged post the attacks on Aramco facilities in September-----: In early September 2019 prices firmed modestly. Immediately before the attack on Aramco's facilities, Brent and WTI were trading at $60.2/barrel and $54.9/barrel respectively. On September 14 the oil market was hit by the proverbial thunderbolt. This was the attack on Aramco's facilities at Abqaiq and Khurais, the heart of Saudi Aramco's petroleum operations. It was the most profound shock to the oil market since Iraq's invasion of Kuwait in July 1990. On September 16 Brent initially surged 20% to $72/barrel, one of the largest intra-day gains on record.

--------but this proved very short-lived: The price surge, however, proved decidedly short-lived. Brent ended September 16th at $69.0/barrel, up 14.6% on the day and below the closing high for 2019 of $74.6/barrel on April 24, 2019. The US Mid-continent benchmark WTI showed a similar gain to $62.7/barrel at the close on September 16th. Over the balance of September light crude prices trended down with Brent and WTI ending the month at $60.8/barrel and $54.1/barrel respectively, or roughly at the pre-attack levels. The averages for September were, however, significantly above August at $62.3/barrel for Brent and $57.0/barrel for WTI. The third quarter averages were $61.9/barrel and $56.4/barrel for Brent and WTI respectively.

Flat price trend end-September-mid-October: Light crude prices trended flat to down between end-September and mid-October 2019. Support was provided primarily by speculation that OPEC will implement another round of production cutbacks following the next meeting at the end of November. A suspected missile attack on an Iranian tanker in the Red Sea on October 11 provided further support. Tending to hold prices in check was the persistence of negative sentiment surrounding the macro-economic and market backdrop. On October 15 Brent and WTI were trading at about $59.2/barrel and $53.4/barrel respectively. These two light oil benchmarks have trended broadly flat over the past three months or so.

The softening price trend since mid-way through the second quarter of 2019 has been consistent with the view expressed in our May report. Given, however, the apparent market tightening in the third quarter as manifested by falling US inventories plus the missile/drone strike on the Aramco facilities, the downward trend has arguably been more pronounced than justified in the circumstances. The explanation probably reflects consensus market expectations of a swing back to surplus in the fourth quarter of 2019 and the challenges of maintaining market balance in 2020, particularly in view of the lacklustre economic and market backdrop.

WHY DIDN'T THE ATTACK ON ARAMCO HAVE A MORE SUSTAINED PRICE IMPACT?

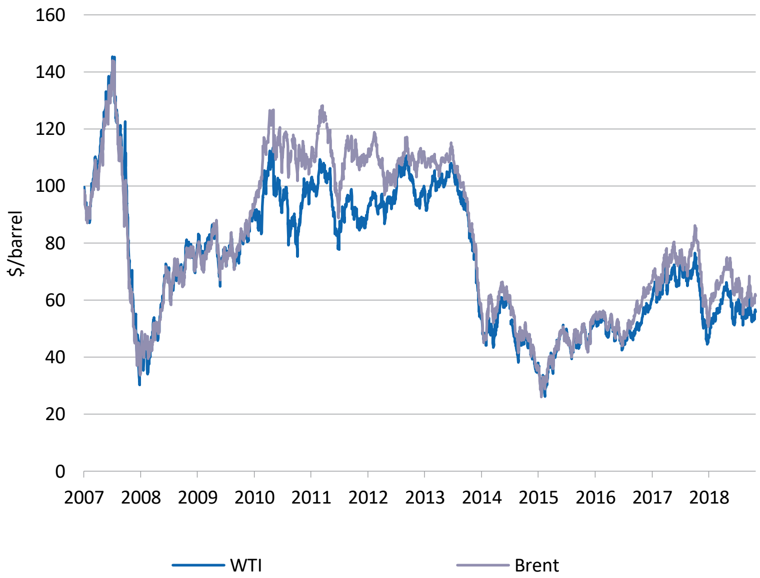
Given the severity and technical sophistication of the attack on the heart of the Aramco operations at Abqaiq and Khurais,, the absence of a sustained price response might appear surprising at first glance. We believe this can be explained as follows:

- **President Trump's cautious stance**: The cautious stance wisely taken by President Trump post the attack. At heart he is an isolationist and has clearly shown no appetite for new military entanglements in the Middle East. In our view, a military response by the US with a strike on Iran would have sent prices very much higher on a sustained basis. Potentially a strike on Iran could have led to a cessation of exports through the Strait of Hormuz and quite possibly large-scale damage to petroleum industry infrastructure in the Persian Gulf.

- **Iran's military and technical capabilities:** By undertaking the attacks on the Aramco facilities, the Iranians have provided an insight into their military and technical capabilities. We think it is now very unlikely that Iran will be challenged in a first strike other than perhaps by Israel. The Iranians are effectively demanding to be taken seriously and shown respect over both the nuclear issue and economic sanctions. In the not too distant future, we believe the Saudis and the US could commence negotiations with Iran to achieve a grand bargain on peaceful co-existence. Such a move could have negative medium-term implications for oil prices bearing in mind the need to allow Iran to recommence oil exports.

- **Aramco's expeditious completion of repairs**: Aramco completed repairs to facilities much quicker than expected. Post the attacks, the consensus view and indeed that of Aramco was that the Abqaiq and Khurais facilities would be out of action in large part for some months, such was the extent of the damage. Repair work was undertaken on a war footing and apparently largely completed by end September. Aramco's production at this time was running at 9.9mm b/d or similar to the level prevailing before the attacks. Furthermore, Aramco's shipments for September seem to have been maintained as scheduled by a combination of running down its own inventories, purchases from third parties and a diversion of crude from its own refineries. The pre-strike capacity of about 12mm b/d is likely to be restored by November, according to Aramco.

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



Source: EIA

Will Iran strike again? This, of course, is a big unknown. We believe much will depend on how US-Iran relations develop. Assuming a continuing mutual state of hostility and the continuation of US sanctions Iran could lash-out once again. Significantly, Iran has suggested that that it will respond to the recent missile attack on its tanker in the Red Sea. Contra-wise a rapprochement between the two countries would presumably preclude further attacks by Iran. Significantly, before the September 14 strike negotiations between the US and Iran were being mooted. We believe that negotiations with Iran would be consistent with a more isolationist US policy stance in the Middle East, including a desire to rundown its local military presence.

PRICE SPREADS

BRENT-WTI

Significant narrowing in recent months-----: The spread between Brent and WTI, the international and US Mid-continent light crude benchmarks respectively, was running at historically elevated levels through much of the second half of 2018 and the first half of 2019 but has subsequently narrowed significantly. In mid-October it was running at about $5.5/barrel, well down on the recent high of $11.0/barrel in late May 2019 and the second quarter average of $9.1/barrel. The third quarter Brent-WTI spread averaged $5.5/barrel and in mid-August hit around an 18-month low of $3.8/barrel.

-----driven by falling inventories at Cushing: The narrowing trend in recent months has been driven by falling inventories at the Cushing, Oklahoma tank farm and signs of slower production growth in Texas and the Mid-continent. Falling inventories reflect, at least in part, new pipeline capacity coming on-stream between the Permian Basin and the Gulf Coast. This, we believe, has reduced the flow into Cushing. We believe the Brent-WTI spread will probably remain narrow by recent historical standards during the fourth quarter given a scheduled further increase in pipeline capacity from the Permian to the Gulf Coast. The caveat is that there is no dislocation to output in the Persian Gulf which would probably boost the price of Brent relative to WTI.

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

Source: Thomson Reuters

WTI (CUSHING)-WTI (MIDLAND)

WTI Cushing-WTI Midland stable in recent months: WTI Cushing (Oklahoma) and WTI (Midland, West Texas in the heart of the Permian) are both light, low-sulphur crude grades with similar API's (specific gravity or relative density). Historically, WTI Midland has sold at a dollar or two discount WTI Cushing. In recent years the Midland discount widened considerably to at times over $5/barrel reflecting the surge in production in the Permian Basin and the lag in installing takeaway capacity. As of mid-October 2019, the WTI Midland discount was around $3.7/barrel which is in line with the experience of recent months.

Considerable pipeline capacity brought on-stream linking Permian with Gulf Coast: Over the past year or so considerable pipeline capacity has come on-stream in the Persian Gulf.tThis has facilitated the flow of oil out of the Permian. Most has been directed to the Gulf Coast. Since late 2018 the new pipelines have been Plains All American Sunrise (500,000 b/d), EPIC (900,00 b/d) and Plains All American Cactus 2 (670,000 b/d). In the fourth quarter of 2019 a further 800,000 b/d of pipeline takeaway capacity is scheduled to come on-stream with Phillips 66's Gray Oak from west of Midland to Corpus Christi on the Gulf Coast. Ongoing, we believe the WTI Midland discount might be about $2.5/barrel which is roughly equivalent to the pipeline spot tariff for carrying oil from Midland to the Gulf Coast.

WILLISTON (BAKKEN) SWEET-WTI CUSHING SPREAD

Bakken discount of $11.5/barrel in line with the historical spread: Crude sourced from the more remote basins in the US typically sells at highly significant discounts to WTI Cushing, reflecting logistical constraints and a lack or absence of local refining capacity. A case in point is Williston Sweet which is a high-grade light oil sourced from the tight Bakken formation in North Dakota. In mid-October 2019 Williston Sweet was selling at $41.5/barrel, a discount of $11.5/barrel to WTI Cushing. The discount has trended broadly unchanged in recent months and is in line with the historical spread. Clearly, the discount implies significantly lower margins, other things being equal, compared with those producers attracting WTI.

SWEET-SOUR SPREADS

After narrowing in late 2018 and early 2019-----Due to the ease of refining, light sweet grades normally trade at a premium to sour heavy grades. A key feature of petroleum markets in late 2018 and early 2019 was a tendency for sweet-sour spreads to narrow or even in some cases to reverse with sour selling at a premium to sweet. The narrowing reflected reduced availability of sour grades with key factors being the US sanctions on Venezuela and Iran, OPEC production cutbacks and the appearance of contaminants in Urals grade crude (a Russia sourced blended medium-heavy sour crude). A start-up of a new refinery in Turkey using sour feedstock in early 2019 was also a factor.

------Brent-Urals spread has widened in recent months: In a European context the benchmark sweet-sour spread is Brent-Urals. During the second and third quarters of 2019 Urals (uncontaminated oil) at times actually traded at a premium to the light-sweet grade Brent. Since late August, however, the Urals discount has been widening and in mid-October 2019 was running at about $4.4/barrel, the widest level in more than a year.

IMO directive to reduce maritime sulphur emissions has boosted demand for Brent: The widening of late appears to reflect buoyant demand for light crudes such as Brent in the wake of the Saudi Aramco outages and in view of the IMO (International Maritime Organisation) directive to sharply (>80%) reduce maritime sulphur emissions from January 1, 2020. The directive requires ship operators to either switch from using high-sulphur heavy fuel oil to low-sulphur middle distillate fuel or to install scrubbers to remove sulphur from exhaust gases.

Louisiana Light-Mars and Maya spreads in line with historical relationships: The key US Gulf Coast sweet-sour benchmarks are Louisiana Light-Mars and Louisiana Light-Maya. Mars is a medium-grade crude sourced from the Gulf of Mexico which normally trades at a dollar or two discount to the high-quality light crude, Louisiana Light. Maya is a heavy crude sourced from Mexico. It typically trades at a discount of $7-10/barrel to Louisiana Light. Many Gulf Coast refineries, it should be noted, are sophisticated facilities designed specifically for heavy crude feedstock. Over the past three months or so Mars and Maya have been trading broadly in line with the historical relationships to Louisiana Light. As of mid-October, the Mars and Maya discounts were approximately $2.9/barrel and $8.4/barrel respectively. The Mars discount has tended to widen over the past month or so.

In 2020 we believe sweet-sour spreads could widen on a sustained basis reflecting the IMO issue mentioned above. The new regulations probably imply a step change in the demand for light sweet feedstock.

WCS-WTI SPREAD

Alberta heavy blended sour grade: WCS (Western Canada Select) is a heavy, blended sour crude comprising a base of Alberta oil sands bitumen diluted with sweet, light synthetic crude and condensate. The API gravity is about 20° against 40° for WTI. Given the variance in specification and the remote sourcing, WCS has historically sold at a $10-20/barrel discount to WTI. WCS, however, provides a very useful source of price-advantaged crude for sophisticated refineries in the Midwest designed for using heavy-sour feedstock. In principle, WCS could also be used by sophisticated refineries along the Gulf Coast which would solve the problem of the declining availability of heavy crude in the region following the loss of Venezuelan supplies and Mexican field depletion. Constrained pipeline capacity from Alberta, however, restricts shipments of WCS to the Gulf Coast.

WCS discount has returned to normal in 2019----After falling to unprecedently low levels in the fourth quarter of about $12/barrel, WCS trended sharply higher through the first 100 days or so of 2019. The recent high was $55.8/barrel on April 9. WCS subsequently slipped early in the second quarter to about $40/barrel and then trended broadly flat at $40-$50/barrel until late September 2019. The trend weakened in early October. At mid-month, WCS was trading at about $36.5/barrel, approximately a ten-month low. Significantly, the discount to WTI has narrowed dramatically from a massive $45/barrel at the low point in the late November 2018 to a more normal $14/barrel in mid-October.

------reflecting Alberta production cutbacks directed by the provincial government: The dramatic narrowing early in 2019 was driven by the Alberta NDP (New Democratic Party) led provincial government ordering a reduction in production of conventional crude and oil sands bitumen in January by the 25 largest producers in the province. The cutback was equivalent to 325,000 b/d. The policy recognised the build-up of inventory in Alberta and the lack of takeaway capacity given delayed pipeline projects. Excess inventories were largely drained during the second quarter.

Alberta cutbacks look like being extended through 2020: Originally the curtailments were expected to cease by end 2019. The new Conservative Alberta provincial government, however, has announced an extension of the curtailments through 2020. The rationale is that continuing pipeline construction delays imply a renewed Alberta inventory build-up, bearing in mind potentially higher production and further pipeline start-up delays.

ALBERTA PIPELINE PROJECTS

Substantial increase in pipeline capacity required for oil sands development: Clearly, to facilitate development of Alberta's substantial oil sands reserves, given the distance from deep-water ports and refining centres outside the province, a large increase in pipeline takeaway capacity is required. Presently, there are three projects either underway or planned.

Three projects of which the Enbridge 3 is the most advanced: The most advanced project is the Enbridge Line 3 from Hardisty, Alberta to Superior, Wisconsin where it links to the Midwest and Ontario pipeline networks. Compared with the current pipeline, which dates to the 1960s and is only operating at 50% of capacity on safety grounds, the new Line 3 would boost takeaway capacity from Alberta by 370,000 b/d. The new pipeline has been delayed by permitting issues but these have now been overcome. Start-up is scheduled for late 2020, at least a year later than originally expected.

The other two are Keystone XL and Trans Mountain: The other two major pipeline projects originating in Alberta are Keystone XL via a direct route (there is already an indirect route) and Trans Mountain Expansion. The former links Hardisty with Steele City, Nebraska and ultimately Cushing and the Gulf Coast and would boost takeaway capacity by about 900,000 b/d. The project has been mired in legal disputes for most of the past ten years. Nebraska's highest court appeared to pave the way for Keystone XL in August by rejecting the case of a diverse group of opponents who wanted to force the project's promoters to reapply for approval. Other legal cases are pending so it is unclear when construction might commence.

Trans Mountain federal government owned and mired in controversy: The Trans Mountain pipeline route runs from Edmonton, Alberta to Burnaby immediately east of Vancouver, British Columbia. The route parallels an existing pipeline built in the early 1950's and would boost capacity from 300,000 b/d to 890,000 b/d. It would facilitate exports of Alberta crude to east Asia markets for the first time. The Trans Mountain project along with the existing pipeline was acquired in June 2018 by the Federal Liberal government from Kinder Morgan for US$3.4bn. It has been given Federal approval. While the project is supported by business, labour groups and the Alberta government it is objected to by an alliance of environmentalists, indigenous groups and the British Columbia NDP (left-leaning New Democratic Party) government. Considerable uncertainty surrounds when work on Trans Mountain might commence. Early 2020 is a possibility. In this case the pipeline could be in operation by end 2022 according to industry reports.

CANADIAN FEDERAL ELECTION AND THE TRANS MOUNTAIN PROJECT

Post the election the Liberals have recommitted to Trans Mountain----Following the Federal election on October 21, the new minority Liberal government, led by Justin Trudeau, expressed its determination to construct the Trans Mountain pipeline 'as quickly as possible'. The pipeline has been legally authorised and has the support of the Conservatives, the largest opposition party. The Conservatives also had the largest share of the vote nationally and almost made a clean sweep of constituencies in Alberta, Saskatchewan and eastern British Columbia in the recent Federal election. Combined, the Liberals and Conservatives have 82% of the seats in the Ottawa parliament. It should also be noted that the energy sector is a major contributor to the Canadian economy. According to Federal government data, energy (the bulk of which is oil and gas) accounts for 11% of GDP and 23% of exports. Canada's largest export is, in fact, petroleum.

-----but potential NDP involvement in an informal coalition could stymie the project: The danger now is that the Liberals will attempt an informal coalition with the NDP which is hostile to petroleum industry interests, including pipeline projects. This could in a worst-case scenario involve the abandonment of the Trans Mountain pipeline. Alternatively, the Liberals and NDP might agree to pursue Trans Mountain but introduce compensating measures detrimental to petroleum industry interests as a quid pro quo. This could, for example, involve raising carbon taxes.

Planned takeaway capacity is sufficient for oil sands projects through mid-2020s. In a best-case scenario, the Alberta oil sands should, have sufficient takeaway capacity by the early 2020s to cater for all planned development projects through the mid-2020s. The caveat is that the Trans Mountain and Keystone XL pipelines are constructed and Enbridge 3 Line is completed. We suspect, however, that future strategic pipeline projects involving the Alberta oil sands could face insuperable obstacles, such is the hysteria surrounding development of this valuable resource.

FORWARD CURVES

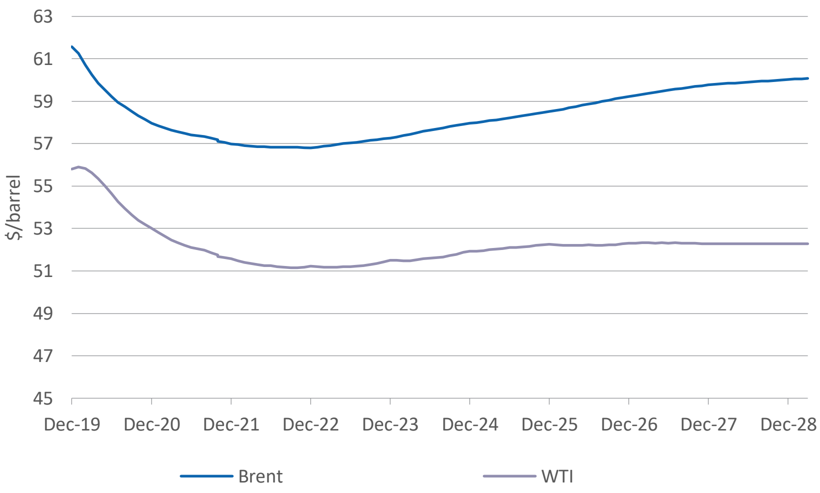
Front-ends in mild backwardation, back-ends mild contango: The front end of the Brent and WTI forward curves have been in mild backwardation (near month prices higher than for the more distant dates) in recent months with the exception of the period post the attack on the Saudi facilities. This resulted in pronounced backwardation for a short period. Contrasting with the flat trend of six months or so ago the middle and back end of the curves for both Brent and WTI are now exhibiting mild contango (near month prices lower than for the more distant dates).

Brent curve trending flat between spot and early 2028: In late October 2019 the Brent forward price for late December 2019 shipments was $59.6/barrel or similar to spot. Forward prices for March and June 2020 were $58.4/barrel and $57.5/barrel respectively. The Brent curve remained in mild backwardation through mid-2021 where it bottomed out at about $56/barrel. The backend of the curve then moved into contango for the remaining forward dates and terminated at $59.3/barrel for shipments in March 2028. From a nine-year perspective the Brent forward curve was therefore flat. The structure of the Brent forward curve would suggest that the market is not anticipating any major changes in the supply/demand balance in the coming years.

WTI in mild backwardation between spot and early 2028: As of late October 2019, the WTI forward curve was in mild backwardation for all dates through early 2022. For December 2019 shipments the WTI forward price was $54.3/barrel or similar to spot. By end 2021 the curve was down to $50.7/barrel and was marginally lower during the first and second quarters of 2022 at about $50.6/barrel. The contango between mid-2022 and early 2028 was very mild at around $1.4/barrel leaving the curve terminating at $52.0/barrel. The mild backwardation in the WTI forward curve between 2019 and 2028 of $2.3/barrel points to expectations of a comfortably supplied market. It probably reflects a positive view of the outlook for development activity in the tight reservoir basins in the years ahead. Compared with six months or so ago, however, the backwardation has been sharply reduced looking out along the curve. The front end of the Brent and WTI curves reflect a spread between about $4.5/barrel and $5.3/barrel. Towards the back end of the curve the spread widens to $8-9/barrel.

Front-end of the WTI curve suggests adequate prices for development activity: Bearing in mind the lead times involved in oilfield development, the forward curve is arguably of greater relevance for petroleum industry investment than the spot price. Within this context US onshore shale oil development lead times are relatively short, so the front end of the curve is of more significance than the back end in making investment decisions. If we look at the front end of the WTI curve between 2019 and 2022 the average forward price is around $53/barrel. This is probably sufficient to achieve fully accounted profitability after allowing for royalties across the more productive tight reservoir plays, notably the Permian, where WTI pricing applies. The situation, however, is considerably more marginal in the remote plays such as the Bakken where realised prices are significantly less than WTI.

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



Source: Thomson Reuters

US SCENE

DRILLING ACTIVITY

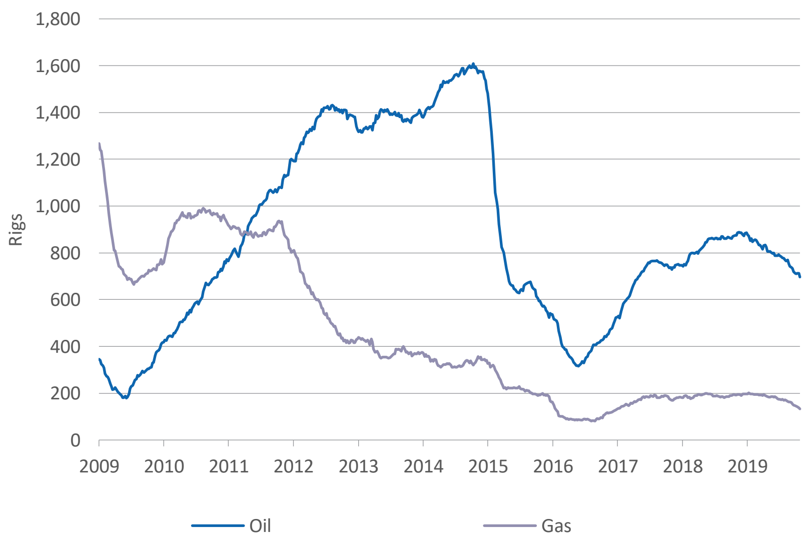
Recent oil-directed trends

Oil-directed rig count continues to slip----: Based on Baker-Hughes data, the US onshore oil-directed rig-count has continued to slip in recent months leaving it well below the peak in recent years of 1,609 reported in October 2014. For the week ended October 11, 2019 the oil-directed rig count was 712, down 18% on a year earlier and 20% on the recent November 2018 high of 888. Despite the slippage of late, the rig count remains well above the low in recent years of 316 in May 2016.

-----reflecting tightening financial availability on mid-tier E&P's: The falling rig count reflects cutbacks in development activity in the principal US tight reservoir basins due to financial constraints and pressure from shareholders in publicly traded companies to boost returns and free cash flow. Rather than production, the mid-tier E&P companies that have pioneered shale oil development, are now emphasising operational free cash flow, paying down debt and dividends. A further negative for drilling activity appears to be declining well productivity in intensively drilled zones.

Permian easily remains the focus of US development activity: Looking at the key shale basins, the Permian (Texas and New Mexico) easily remains the focus of development activity in the US. The oil-directed rig-count here on October 11 was 421 or 59% of the US total against 56% a year earlier. The absolute rig count was however down 14% on 2018. The recent high for the Permian was 493 in late November 2018. Among the other tight reservoir basins rig counts in mid-October were 50 in the Eagle Ford (Texas), 55 in the Williston (Montana and North Dakota), 33 in the Cana-Woodford (Oklahoma) and 21 in the DJ-Niobrara (Colorado, Wyoming). The rig-count was actually up year-on-year in the Williston but down 48% in the Cana-Woodford, 25% in the DJ Niobrara and 26% in the Eagle Ford.

EXHIBIT 5: BAKER HUGHES US RIG COUNT (RIGS)



Source: Baker Hughes

THE WELL PRODUCTIVITY ISSUE

Slowing well productivity growth has surfaced over the past year or two---- Since the great shale oil revolution commenced in the early 2000's, truly impressive increases in well productivity have been achieved each year through advances in horizontal drilling and completion technology. The key developments have been ever longer lateral sections, multi-stage fracking, increasing frack pressures and the more intensive use of sand as a fracking proppant. According to industry reports, initial well production rates 30 days (IP-30) after being brought on-stream in key tight reservoir basins have increased by around 30% pa on average in recent years. Industry sources are now suggesting however that growth has slowed dramatically over the past year or two and may now be in low single digits at best. Initial production rates after 90 days (IP-90) have also been under pressure.

-----apparently reflecting down-spacing: Declining productivity growth in the tight reservoir basins of the US appears to reflect in large part the down-spacing of wells from a typical 500 to 600 ft a few years ago to 375 ft. Broadly, this results in an increase in the number of wells per typical two square mile drilling unit from about 16 to 32. The theory behind tighter spacing is that it improves recovery rates, increases reserves, leverages the use of centralised field production facilities and maximises returns per acre. Experience is now suggesting that the tight spacing results in interference between wells thereby reducing pressure and hence production rates. In a worst-case scenario wells can be permanently damaged.

Parent-child well phenomenon with the former cannibalising the latter: Declining productivity is often associated the parent-child phenomenon. The parent well is the first to be drilled while the child is the follow up infill well drilled close to the parent. Often it appears the child wells cannibalise the parent and lower reservoir pressure and production rates. A classic case of the law of diminishing returns. Significantly, child wells already account for 70% of those drilled in the Eagle Ford and 70% of the Midland basin in West Texas.

Solutions such as returning to conventional well spacing involve higher costs: The simple anecdote to declining well productivity in mature drilling zones appears to be a return to conventional spacing. This could imply higher operating costs per barrel but would, of course, result in the need to drill fewer wells. There may also be a need to exploit new prospective zones in mature basins or focus more on underdeveloped basins both inside and outside the US.

Declining well productivity in the more heavily drilled zones could also be addressed by using longer horizontal sections and more intensive fracking. With horizontal sections already reaching 10,000 ft or about two miles and multi-stage, high-pressure fracking widely applied further advances on these two fronts will presumably prove challenging.

THE MAJORS PICK-UP THE BATON

Belatedly the majors are joining the tight reservoir party: The oil and gas majors have lagged development of the tight oil and gas reservoir basins of the US Great Plains and Texas. They are, however, now catching up rapidly in the development stakes. ExxonMobil and Chevron have the most advanced programmes particularly in the Permian but Royal Dutch Shell, BP and ConocoPhillips are all very active in the tight reservoir basins. Occidental Petroleum is also now a major player in tight reservoir development following its acquisition of Anadarko earlier in 2019.

Encouraging Exxon and Chevron drilling results in the Permian: Significantly, the drilling results reported by Exxon and Chevron in the Permian have been very encouraging. Production performance has exceeded expectations based on play type curves while production has been growing rapidly. Exxon's Permian production increased 21% between the first and second quarters of 2019 to 274,000 boe/d and was up 90% on a year earlier. Chevron's Permian production in the second quarter of 2019 at 421,000 boe/d was 56%

higher than in 2018. Exxon and Chevron have emerged over the past year or two as among the larger players in the Permian basin.

THE MID-TIERS BULK-UP

Recent flurry of M&A activity: Three mid-tier US E&P plays have recently agreed or announced deals to merge reflecting a desire to leverage costs and bulk-up on shale development opportunities. The three deals involve Parsley Energy and Jagged Peak Energy, Callon Petroleum and Carrizo Oil & Gas and Whiting Petroleum and Abraxas Petroleum. The Parsley Energy and Callon led deals are primarily focused on the Permian Basin. Whiting, historically a major Bakken focussed company, through its planned acquisition of Abraxas will both expand in the Bakken and gain exposure to the Permian Basin for the first time.

RECENT GAS-DIRECTED DRILLING TRENDS

Natural gas directed drilling at a low ebb---Natural gas-directed drilling in the US has remained at a low ebb historically in recent months. For the week ended October 18, 2019 the gas-directed rig count was 137, down 29% on a year earlier and with the exception of the ultra-depressed conditions of 2016, a multi-year low.

-----reflecting a very weak prices backdrop: The gas-directed rig count has continued to be depressed by a very weak price environment reflecting plentiful supplies and lagging demand. Substantial quantities of by-product gas are being produced in the Permian and other tight reservoir basins. In late October the benchmark Henry Hub spot was around $2.25/mmBtu which is slightly above recent lows of approaching $2/mm Btu but has been hovering not far from a ten-year low.

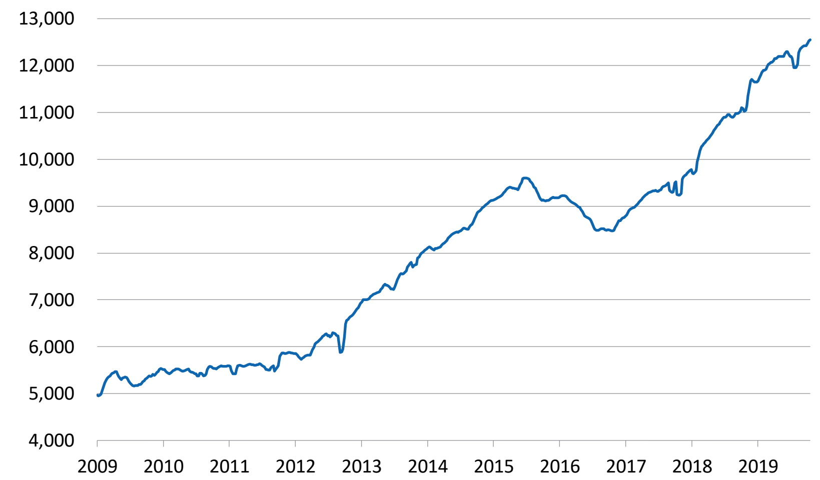
Ultra-low gas prices in the Midland Basin TX but situation recently alleviated by the new Gulf Coast Express pipeline: Interestingly, spot prices at the Waha hub in the Midland Basin were significantly negative at times in April 2019 and averaged only about 65 cents/mm Btu through the first eight months of the year. Since August the Waha price has firmed reflecting the commissioning of the Gulf Coast Express pipeline linking Waha with the Agua Dulce hub on the Gulf Coast. From here gas can be shipped to either Mexico or Houston or converted to LNG. Waha spot was around $1.35/mm Btu in late October. Such a price, however, would be insufficient to justify gas-directed drilling from a financial perspective. In, our view, to encourage a sustained rise in US gas-directed drilling activity would necessitate a Henry Hub price of comfortably over $3/mm Btu. This would probably imply sufficient headroom above fully accounted cost to justify an adequate financial return.

PRODUCTION

Crude

Production hit in Q3 hurricane-related outage on the GOM: After growing by 15% year-on-year in both the first and second quarters of 2019 US crude production growth slowed to about 9% in the third quarter, based on EIA data. The slowdown was mainly driven by outages associated with Hurricane Barry in July. These reduced Gulf of Mexico output between the second and third quarters by 110,000 b/d. In the Lower 48 the trend remained upward between the second and third quarters but the year-on-year pace slowed from 16% in the first half to 11% in the third quarter. Early indications for the fourth quarter of 2019 point to growth regaining momentum.

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



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

Record production: Crude production has continued to hit new records of late and is at a level that few thought possible until recently. Taking the four weeks to October 18, 2019 production averaged 12.55 b/d. This was up 7.7% on end 2018 and 13.4% on a year earlier. It must be remembered that ten years ago, close to the nadir, US crude production was running at only 5.2mm b/d. Based on EIA data, the quarterly progression in US crude output between the first quarters of 2018 and 2019 is as shown in Exhibit 7.

The key driver behind US crude production in 2019 has continued to be development activity in the tight reservoir basins of the Great Plains and Texas, with the Permian particularly significant. As in recent years, the Gulf of Mexico has also played a significant part in boosting production in the year-to-date despite the hurricane impacted third quarter. In the third quarter of 2019 we estimate that crude production was up year-on-year about 1.2mm b/d in the tight reservoir basins and down around 0.2mm b/d elsewhere.

Tight reservoir production: According to EIA data, tight reservoir oil production (crude and natural gas liquids) in the third quarter of 2019 was running at 8.7mm b/d or about 51% of the US total. The Permian Basin accounts for half of tight reservoir production. The weightings of the next four largest tight reservoir plays, Bakken, Eagle Ford, Niobrara and Anadarko are 17%, 16%, 8% and 6% respectively.

EXHIBIT 7: US CRUDE OIL QUARTERLY PRODUCTION

	Q1	Q2	Q3	Q4	Total
2018 mm b/d	10.27	10.54	11.25	11.89	10.99
YOY %	13.5	15.7	20.6	20.1	17.5
2019 mm b/d	11.81	12.11	12.24	12.87	12.24E
YOY %	15.0	14.9	8.8	8.2	11.6
2020 mm b/d	13.05	13.15	13.18	13.31	13.17E
YOY %	10.5	8.6	7.7	3.4	7.4

Source: EIA. Note: Data are actuals to Q3 2019

Natural gas liquids and hydrocarbon substitutes

The US produces substantial quantities of natural gas liquids (NGLs) and renewable fuels in the form of ethanol and bio-diesel. Growth has remained buoyant driven in particular by the substantial quantities of wet gas produced as a by-product of oil-directed development, especially in the Permian Basin. In the four-weeks to October 18, 2019 production of NGL'S and renewables net of refinery processing gain was 6.82mm b/d, up 3.7% on a year earlier. NGL production at 4.71mm b/d was 7.2% higher than a year previously while renewable fuel and fuel additives showed a decline of 2.6%. As for crude, NGL and other liquids production is around record levels.

Taking both crude and NGL's/other liquids, US hydrocarbon/renewables production in the four weeks ended October 18, 2019 was 19.37mm b/d, 10.0% higher than a year earlier. This is equivalent to about 92% of domestic consumption.

FORECASTS

EIA forecasting oil production growth of 9.7% in 2019 and 8.0% in 2020: Near-term, the EIA is forecasting further highly significant growth in US hydrocarbons liquids production, although at a slower pace than 2018's 15%. After increasing by 9.7% to 19.68mm b/d in 2019 the EIA is looking for growth of 8.0% to 21.26mm b/d in 2020. Slowing growth reflects a combination of the lagged effect of declining drilling activity and slowing gains in new well productivity. Within the total, crude production on average is forecast by the EIA at 12.26mm b/d (+11.6%) and 13.17 mm b/d (+7.4%) in 2019 and 2020 respectively. The forecasts are similar to those given earlier in 2019.

The EIA's scenario suggests that the US will be slightly more than self-sufficient in hydrocarbon and other liquids in 2020. This is something that we believe has not been achieved in 50 years or more.

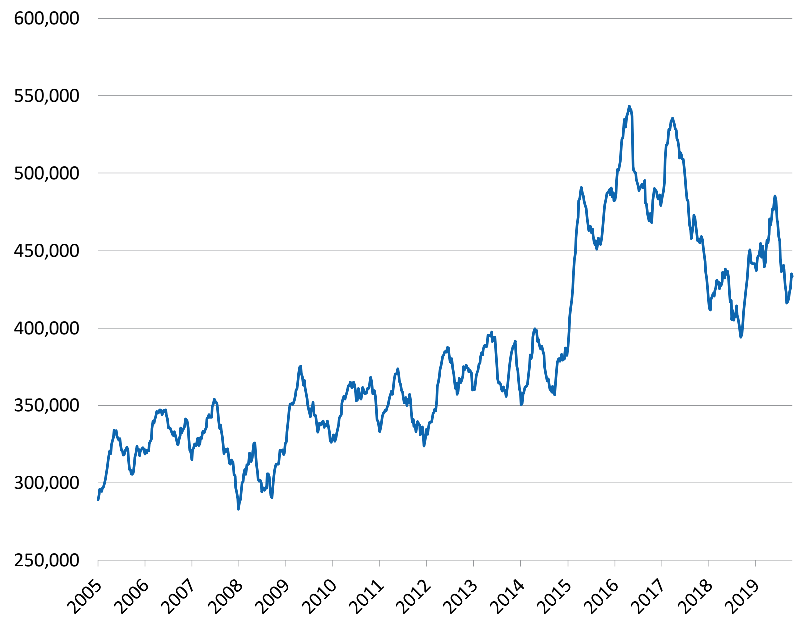
US number one for both crude and total liquids: The US has been the world's largest producer of hydrocarbon and other liquids for several years and in 2018 also became the number one in crude oil. Based on the EIA's forecasts for 2019 and 2020, the US is likely to increase its lead over the next two producers, Russia and Saudi Arabia. Currently, these two countries produce approximately 11.5mm b/d and 12.4mm b/d respectively, including NGL's and other liquids.

INVENTORIES

US crude

Downward trend since mid-June 2019: US crude inventories trended significantly higher from late 2018 through mid-June 2019. Subsequently they have trended down both absolutely and on a days' supply basis. For the week ended October 18, 2019 commercial crude inventories stood at 433.2mm barrels, down 11% on the recent high of 485.5mm at the beginning of June 2019 but still up 2.5% on a year ago. On a days' supply basis crude inventories on October 18 were equivalent to 27.5 against 25.9 a year earlier. Either on an absolute or a days' supply basis, crude inventories in mid-October were in line with the experience of the past five years. Absolute inventories were, indeed, very close to the average of the five-year range for the time of year. We believe the declining trend in US crude inventories in recent months has been driven in large part by rising exports assisted by new pipeline capacity from the Permian Basin to the Gulf Coast.

EXHIBIT 8: US CRUDE OIL INVENTORIES (THOUSAND BARRELS)



Source: EIA

Based on the EIA's forecasts, US crude inventories are forecast to trend higher over the balance of 2019 and early 2020. The peak of about 483mm barrels is however well within the five-year range. It should however be noted that given buoyant US production, the emergence of substantial exports and the often lumpy nature of imports, US crude inventories are particularly difficult to forecast.

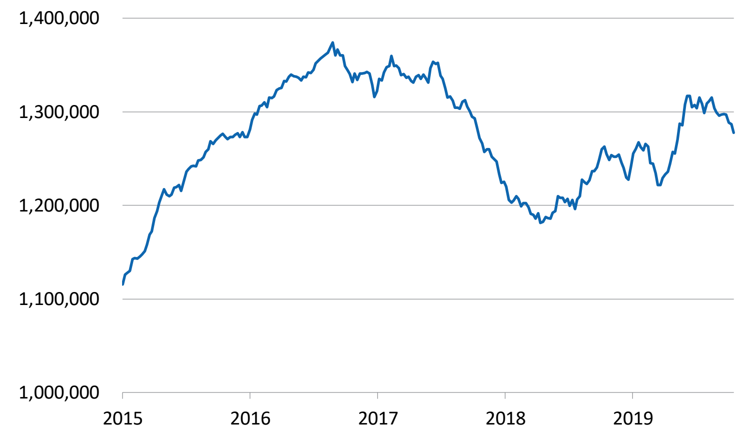
Cushing

Inventories edge up in recent weeks: Cushing, Oklahoma is the location of the largest tank farm and oil trading hub in the US. Significantly, it is the settlement point for WTI on Nymex. Crude inventories at Cushing also trended higher between late 2018 and June 2019 before declining in the three months to mid-September. Subsequently Cushing inventories have edged higher and on October 18th stood at 44.5mm barrels. They nevertheless remained 17% below the historically high June 2019 peak of 53.6mm barrels. Based on the experience of the past five years, Cushing inventories have ranged between 18mm and 67mm barrels so the mid-October level should be considered normal in the context of the recent history. With new pipeline capacity coming on-stream between the Permian Basin and the Gulf Coast, the flow into the Cushing tank farm could slacken in the coming months.

Crude and product commercial inventories

Trending flat of late: Given fluctuations in refinery utilisation and crude oil imports and exports, the most insightful way of looking at inventories is on an all-encompassing basis, including both crude oil and refined product. On this broad definition, inventories climbed markedly between the first quarter and early June 2019 but have subsequently trended flat to slightly down at levels modestly below the recent peak of 1,374mm barrels in August 2016. All-encompassing inventories stood at 1,278mm barrels on October 18, 2019, down 3% and 7% on the June 2019 and August 2016 highs respectively. Inventories currently are equivalent to about 61 days' supply which constitutes a very comfortable level historically.

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



Source: EIA

Gasoline inventories

Trending flat towards the top of the five-year range: US gasoline inventories have trended broadly flat since the end of the first quarter of 2019 and are towards the top end of the five-year range seasonally. Inventories on October 18 stood at 223.1mm barrels, down 3% on a year ago. The days' supply has also trended flat in recent months. At October 18th the day's supply was 23.8, down from the 25.0 of a year ago and well below the high in recent years of 31.3 in January 2017. Currently, the gasoline days' supply is towards the lower end of the range over the past five years of 22 to 32.

Distillate inventories

Trending flat at the low end of the seasonal range: US distillate inventories have also trended broadly flat over the past two years abstracting from marked seasonality related to heating oil usage. For the week ended October 18 distillate inventories came in at 120.8mm barrels, down 7% on a year earlier and 25% on the recent high of 170.7 mm barrels reported in March 2017. Contrasting with gasoline, distillate inventories over the past two years have been trending well towards the lower half of the five-year range. In fact, in the most recent week inventories were slightly below the lower point of the five-year range. The distillate days' outstanding on October 18 were 29.4, slightly down from a year earlier and in line with the trend in 2019 year-to-date. Compared with peak levels in early 2016 of 47, the days' outstanding have fallen substantially.

Propane

Inventories are running at a historically high level: Propane inventories fluctuate sharply seasonally but in 2019 the upturn from the first quarter has been especially pronounced. This has taken inventories close to 25-year high. As of October 18, propane inventories were 100.0mm barrels, 22% ahead of a year earlier and equivalent to a historically high 88.1 days outstanding. This compared with 74.4 days a year earlier.

NET TRADE BALANCE

Sharp narrowing in the net import balance over recent years----: One of the most profound US petroleum industry developments over the past12 years or so has been the dramatic narrowing in the net import balance for crude and refined products. At the peak in late 2005 the deficit hit a hefty 13.5mm b/d but for the four weeks to October 18, 2019 a modest surplus of 49,000 barrels was, in fact, reported.

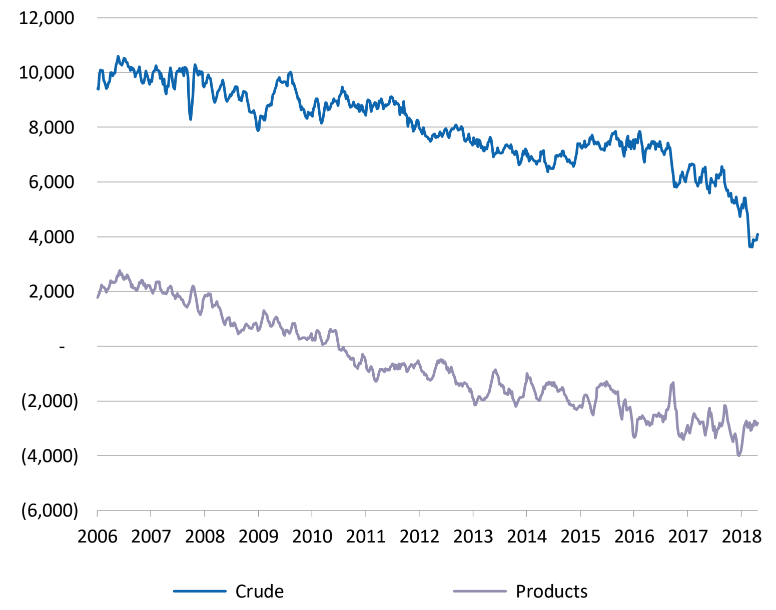
------with a swing to surplus likely in 2020: After a deficit of 0.54 mm b/d in 2019 the EIA is looking for a trade surplus of 0.62 mm b/d in 2020. These forecasts reflect an even more bullish picture than earlier in the year when the equivalent numbers were a deficit of

0.85mm b/d and a surplus of 0.58mm b/d respectively. Assuming the forecast net trade surplus materialises, we believe it will be the first for the US in at least 60 or 70 years.

The narrowing in the overall trade deficit was initially driven by a swing to surplus on the refined product front. On an annual basis the first surplus emerged in 2011. The US has benefited in recent years from the internationally highly competitive refinery infrastructure along the Gulf Coast supported by the ready availability of cost advantaged feedstock and natural gas. In recent years the Gulf Coast refineries have been well placed to take advantage of outages and capacity constraints together with buoyant demand in the Atlantic Basin in general and Latin America in particular. Mexico is the leading destination for exported refined product with shipments of about 1.1mm b/d currently.

Not surprisingly, perhaps, the trend of widening refined product surpluses has levelled off over the past year or two. Based on EIA data, the product balance showed a year-on-year decline of 10% in the second quarter of 2019 while in the four-weeks to October 18, 2019 there was a similar fall to 2.92mm. According to the EIA, product net export shipments were up year-on-year by 8% in the third quarter. A further gain of 15% is expected in the fourth quarter which would result in an increase of 6% to 3.58mm b/d for 2019 as a whole.

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



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

Since the historical US crude oil export ban was lifted at the end of 2015 shipments outside the US have surged. Taking the four-week period to October 18, 2019 export shipments were 3.30mm b/d against 2.07mm b/d a year earlier. Propelling exports of late have been the availability of low-cost crude from Texas and elsewhere, new pipeline capacity taking oil from the Permian Basin to the Gulf Coast and upgraded Gulf Coast loading infrastructure. Imports, although well down on the historic high of over 11mm b/d, in 2006 nevertheless remain significant at 6.17mm b/d in the latest four-week period. In the four weeks to October 18 the EIA reported a net deficit on crude of 2.87mm b/d, down 48.8% on a year earlier. Canada remains the dominant source of crude imports accounting for about 53% of the total currently. Many of refineries along the Gulf Coat are configured for heavy-sour feedstock whereas the oil shipped from the shale basins is light and sweet. This has led to a build-up of light crude along the Gulf Coast which is available for export.

Near-term, a potential constraint on crude oil exports is the narrowing Brent-WTI spread. Clearly, a narrowing spread reduces the incentive to export. The EIA's forecast for exports in 2020 is predicated on a Brent-WTI spread of $5.4/barrel. Significantly, after a sharp narrowing in the net import crude balance between 2018 and 2019 from 5.72mm b/d to 4.12mm b/d the EIA is looking for a broadly flat trend in 2020.

DOMESTIC DEMAND

2019

Underlying trend in US petroleum demand flat to marginally up in 2019. Taking the four weeks to October 18 demand came in at 21.06mm b/d, up 3.4% from a year earlier. For the period the largest product lines gasoline, distillates, kerosene and propane showed year-on-year movements as follows: +2.3%, +0.8%, +5.8% and +3.0% respectively. On the same basis residual fuel oil demand declined 5.7% while the large miscellaneous category, which includes natural gas liquids (NGL), was up 8.5%. NGL consumption has been growing rapidly in the US driven by new ethylene cracking capacity coming on-stream.

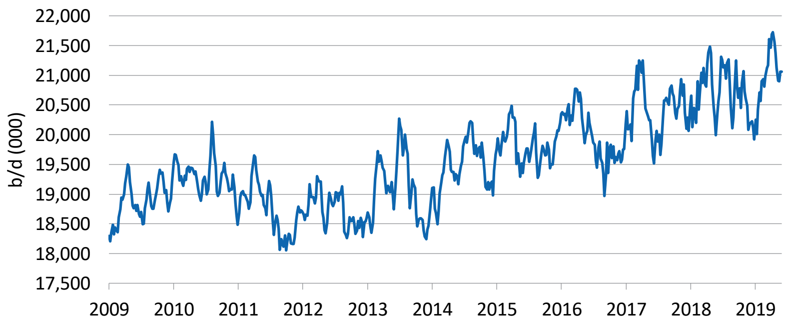
EIA forecasts 0.2% growth in 2019----For 2019 as a whole the EIA is forecasting modest product demand growth of 0.2% to 20.54mm b/d. This reflects a slight downgrade from 20.8mm b/d forecast last April. We believe the demand for gasoline, the largest product line (about 45% of the total) by far, has been supported by prices which in real terms are towards the low end of the range for the past ten years. As of mid-October2019 gasoline across all grades was selling at approximately $2.74/gallon in the US. This was down 7% on a year earlier.

2020

-----followed by 1.1% in 2020: For 2020 the EIA is forecasting US demand growth of 1.1% which would take volume to 20.76mm b/d or around the 2005 all-time high. The forecast is based on GDP growth of 2.1%, an average retail gasoline price (all grades) of $2.69/gallon, up 1.5% on 2019 and a 1.2% increase in vehicle miles travelled. Again, product demand is expected to be driven by hydrocarbon liquids which are forecast to show a year-on-year gain of 6.9%. By-contrast, gasoline, distillates and kerosene are forecast to be roughly unchanged between 2019 and 2020 while fuel oil and miscellaneous are expected to be down slightly

The EIA's GDP growth assumption for 2020, we believe, could be optimistic given increasing evidence of a sluggish industrial economy. Sub 2% growth is arguably more likely. In this case demand could be unchanged or even decline modestly in 2020. Much will depend on the direction in gasoline and distillate prices. A softening trend will clearly help support demand in such circumstances.

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



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

SUPPLY-DEMAND BALANCE

2019

Market tightened in 2019 and was in significant deficit in Q3, balance for the full year: After being in significant surplus of around 2mm b/d in the fourth quarter of 2018 the global petroleum market has tightened in 2019. Through the first three quarters it was, in fact, not too far away from balance. Based on EIA data, the market is estimated to have generated moderate surpluses of 0.44mm b/d and 0.10mm b/d in the first and second quarters of 2019 respectively. Reflecting the Saudi outage in the wake of the attacks on Aramco's oil infrastructure the market swung into a significant deficit of 0.83mm b/d in the third quarter. The EIA is looking for a modest surplus in the fourth quarter of 2019 of 0.28mm b/d with key drivers being a rebound in Saudi output and generally lacklustre demand. The implied forecast for the full-year is a deficit of 0.02mm b/d or approximate balance. This compares with a forecast surplus of 0.24mm b/d prior to the attacks and an estimated surplus for 2018 of 0.83mm b/d.

During the first three quarters of 2019 the petroleum market was subject to three key forces. These were as follows:

- A pronounced slowdown in global demand growth in both the OECD and non-OECD worlds.
- Falling OPEC output reflecting the 1.2mm b/d production cutback accord agreed in late 2018, the outages in Saudi Arabia following the September 16 attacks and US sanctions on Iran and Venezuela.
- Slower, albeit still buoyant, growth in non-OPEC production than in 2018.

Broadly-based economic slowdown constraining demand growth: Global demand in 2019 has been hit by a broadly-based economic slowdown in the OECD and non-OECD worlds. Compared with consensus growth forecasts of 1.4-1.5mm b/d at the beginning of 2019, expectations are now closer to 1mm b/d with the EIA down at 0.8mm b/d. Demand growth in 2019 looks like being the lowest in more than five years.

OPEC output potentially down over 2mm b/d in 2019: OPEC crude output in 2019 could drop 2.1mm b/d or 7% to 29.8mm b/d, according to the EIA. This comfortably exceeds the decline of 1.2mm b/d implied by the OPEC+ accord with the key factors being the outages in September in Saudi Arabia and sharply declining output in Iran and Venezuela. As a result of the outages, the EIA estimates that Saudi production fell by 1.4mm b/d between August and September but as noted previously Aramco's operations returned to normal by early October. Both Iran and Venezuela have been impacted by US sanctions while the latter has additionally been hit by atrophying infrastructure and skilled labour shortages. Since the commencement of sanctions Iran has lost about 2mm b/d of exports. China remains the only sizeable customer.

Based on EIA data, Venezuelan production fell year-on-year about 40% to 860,000 b/d in the year-to-date September 2019. According to industry reports production was running at only about 600,000 b/d in September and by end 2019 could be down to 300,000 b/d, an unprecedentedly low level. The accelerating rate of decline over the balance of the year reflects in part a possible cessation of operations at Chevron's joint-ventures with PDVSA at the end of October. Presently Chevron is operating under a US Treasury sanction's waiver until this time. The Russian major, Rosneft, may takeover the Chevron joint-ventures and according to industry reports could restore production within a month or two.

Tight compliance with the OPEC+ production accord except for Iraq and Nigeria: Generally, producer compliance with the OPEC production accord appears to have been tight so far in 2019 with the exception of Iraq and a lesser extent Nigeria. Iraq, the second largest OPEC producer, has boosted production from a year earlier by 4% to about 4.73mm b/d. Recently production here hit a record 4.88mm b/d, according to Standard & Poors reflecting heavy power station oil usage during the summer months and pressing government financing needs. Iraq is apparently committed to achieving compliance with the OPEC quota but inevitably, in view of the history of non-compliance, this is a key area of uncertainty concerning the oil market outlook. Nigeria's production has trended higher in 2019 from the historically depressed levels of late 2018. Through the first three quarters of 2019 production was up from a year earlier by a modest 3% to 1.65mm b/d, according to the EIA but in the third quarter alone showed a gain of 11%. Based on industry reports, Nigerian production of late has been running at about 1.86mm b/d, the highest level in almost four years.

Libyan production significantly higher in 2019: Outside the remit of the OPEC accord, Libyan production has also risen significantly in the year-to-date September 2019. The year-on-year gain has been 14% to 1.07mm b/d based on EIA data. Recent production rates of about 1.16mm b/d are around a six-year high. Arguably this has been a surprisingly strong performance given civil war conditions in the country. The main fight now pits the UN recognised government in Tripoli in the west of the country against the forces of General Haftar. He is backed by Egypt, the UAE and more tentatively France and the US, from his base in Benghazi in the east of Libya. It should be noted that Libya's production has tended to exceed consensus expectations for some years.

General Haftar bogged down in push on Tripoli: General Haftar's earlier push to take control of Tripoli has become bogged down. Just how the conflict between the eastern and western forces in Libya will be resolved is an open question. One possibility would appear to be a new agreement between the eastern and western governments on the split in oil revenues. The eastern government has complained, with some justification, that it does not receive enough of the spoils given that it hosts the bulk of Libya's oil production facilities.

As far as oil production is concerned, the best working assumption is probably that it will remain above 1mm b/d for the foreseeable future. Any resolution of the civil war could result in a boost in production towards the levels of 1.5-1.6mm b/d prevailing prior to the overthrow of Colonel Gaddafi in 2011. Libya's reserves would in theory sustain an even higher level of production but this will require heavy investment.

Slowing non-OPEC production but still buoyant historically: Non-OPEC supply growth was exceptionally rapid in 2018 at 2.77mm b/d or 4.6%. This was one of the strongest performances on record. Not unexpectedly growth has slowed in 2019 with the key factors being the slowdown in the US and the Alberta provincial government orchestrated production curtailments mentioned earlier. Nevertheless, the trend in non-OPEC output is still buoyant in 2019. The EIA is looking for a gain of 2.1mm b/d with the key drivers being the US (+1.73mm b/d), Brazil (+0.19mm b/d) and Canada (+0.10mm b/d). Interestingly, in the North Sea the Equinor (formerly Statoil) operated giant Johan Sverdrup field in the Norwegian sector has recently commenced production ahead of schedule. The planned production rate is 0.44mm b/d in phase 1. In the UK sector production is receiving a modest boost in the second half of 2019 following the start-up of Equinor's Mariner heavy oil project west of Shetlands. Equinor is expecting Mariner peak production of 70,000 b/d.

2020

Similar market backdrop to 2019, sluggish demand growth, buoyant non-OPEC output growth, lower OPEC production: We believe that the underlying petroleum market backdrop in 2020 will be similar to 2019. A sluggish world economy, we think, will carryover thereby limiting the scope for demand growth probably to no more than in the previous year. Non-OPEC output is likely, in our view, to continue on an historically rapid growth path driven by the US, Brazil, the Norwegian sector of the North Sea and Guyana. Canada could also be a significant contributor depending on the scale of the Alberta curtailments and the start-up of the Enbridge 3 pipeline. Based on industry reports, Brazilian production could increase by over 0.3mm b/d in 2020 reflecting intensive development activity in the pre-salt zone of the Santos Basin. This includes the addition of new FPSO's (floating, production, storage and offloading vessel) in the Lula and Buzios fields.

Exxon to commence offshore Guyana operations: It should also be noted that ExxonMobil's Liza Phase 1 operated project offshore Guyana is scheduled to come on-stream by early 2020 at a production rate of 120,000 b/d. Offshore Guyana is likely to become a sizeable new oil production province over the next few years given the planned start-up of Liza Phase 2 (220,000 b/d) by mid-2022 and subject to government approval the Payara project (220,000 b/d) by 2023.

Continuation of OPEC+ production accord and US sanctions on Iran and Venezuela: In the near-term, at least, we expect the OPEC+ Russia production accord to be retained along with the US sanctions regimes applied to Iran and Venezuela. We believe the picture painted for 2020 points to a year of modest supply surplus. Our forecast calls for one of 0.29mm b/d, down on our earlier forecast of 0.43mm b/d. The downgrade reflects adjustments to the prior year and lower non-OPEC growth and a larger cut in OPEC output than originally expected. Specifically, the new forecast for 2020 reflects the following:

- Global demand growth +1.00mm b/d
- Non-OPEC output growth +1.94mm b/d
- OPEC crude production -0.33mm b/d
- OPEC NGL production -0.30mm b/d

Note, the decline in OPEC NGL production results from falling crude production. Our forecast for OPEC crude production of 29.50mm b/d exceeds the OPEC call of 29.21mm b/d reflecting the assumption that there will be some slippage regarding the OPEC production accord.

Modest supply surplus for full-year 2020: Our forecast of a supply surplus in 2020 of 0.29mm b/d is similar to the 0.32mm b/d forecast by the EIA. For 2020 our global GDP growth assumption (oil-weighted) is 2.2%. This compares with 2.4% for the EIA and reflects our more bearish view of the outlook for the world economy in 2020. For perspective, world GDP growth (oil weighted) in 2018 was 3.0% and in 2019 is estimated at 2.0% based on EIA data.

Surpluses difficult to avoid assuming strong non-OPEC output growth

We believe that petroleum market supply surpluses will be difficult to avoid if non-OPEC output continues to increase by in excess of 1.5mm b/d. Demand growth globally is very unlikely to exceed this amount for long in our view based on the experience of the past few years. Furthermore, we believe it is highly unlikely that OPEC will be willing to accommodate rising non-OPEC output indefinitely.

It also needs to be borne in mind that several OPEC producers such as Iraq, Libya and Nigeria are all planning to increase output medium to long term while at some stage OPEC will need to leave room for a return to full capacity working at Iran and Venezuela. This, of course, will require a lifting of US sanctions. In practice it is unlikely that higher output at Iran and Venezuela will be fully offset by other OPEC members. Significantly, there has been some discussion in trade circles of a rapprochement orchestrated by the mercurial President Trump between the US and Iran. Such a move would be analogous to the attempted rapprochement with North Korea.

EXHIBIT 12: GLOBAL OIL SUPPLY/DEMAND BALANCE

Mm b/d	2014	2015	2016	2017	2018e	2019e	2020e
Global consumption	93.92	95.91	96.96	98.59	99.98	100.82	101.82
Non-OPEC oil production	59.11	60.69	60.03	60.75	63.52	65.59	67.53
OPEC NGL production	**5.18**	**5.19**	**5.25**	**5.30**	**5.33**	**5.38**	**5.08**
OPEC crude call	29.63	30.03	31.68	32.54	31.13	29.85	29.21
OPEC crude production	29.98	31.22	32.21	32.07	31.96	29.83	29.50
Surplus/(deficit)	**0.35**	**1.19**	**0.53**	**-0.47**	**0.83**	**-0.02**	**0.29**
Global production	94.27	97.10	97.49	98.12	100.81	100.80	102.11
Non-OPEC share of global production %	62.7	62.5	61.6	61.9	63.0	65.1	66.1
YOY changes %							
Global consumption	1.8	2.1	1.1	1.7	1.4	0.8	1.0
Non-OPEC crude production	4.6	2.7	-1.1	1.2	4.6	3.3	3.0
OPEC crude production	0.1	4.1	3.2	-0.4	-0.3	-6.7	-1.1
Global oil production	2.8	3.0	0.4	0.6	2.7	0.0	1.3
YOY changes mmb/d							
Global consumption	1.66	1.99	1.05	1.63	1.39	0.84	1.00
Non-OPEC crude production	2.59	1.58	-0.66	0.72	2.77	2.07	1.94
OPEC crude production	0.03	1.24	0.99	-0.14	-0.11	-2.13	-0.33
OPEC NGL production	-0.02	0.01	0.06	0.05	0.03	0.05	-0.30
Global oil production	2.60	2.83	0.39	0.63	2.69	-0.01	1.37
World GDP growth (oil weighted) %	3.0	2.9	2.8	3.1	3.0	2.0	2.2
US GDP growth (2012 dollars) %	2.5	2.9	1.6	2.4	2.9	2.3	2.2

Source: EIA and Allenby Capital

CRUDE OIL PRICE OUTLOOK

MARKET THESIS
2019

Weak trend in Q3 in line with our expectations but prices lower: The trend in benchmark light crude prices in the third quarter of 2019 was in line with the scenario outlined in our May 2019 report. Compared with our expectations of a few months ago, however, price levels have been lower. Our earlier scenario called for the upward trend apparent in the first quarter of 2019 to continue in the second quarter as the OPEC+ Russia production cutback accord and the US sanctions regimes on Iran and Venezuela gained traction. After peaking in the second quarter, prices were then expected to dip through the third and fourth quarters as non-OPEC output increased and demand growth slowed.

Key negative for prices in Q3 was bearish developments on the macro-economic and demand fronts: For the second and third quarters we were looking for Brent to average $72.5/barrel and $68/barrel respectively. The actuals were $68.9/barrel and $61.9/barrel. The variance reflects two key factors. Firstly, was there was the continuing strength of non-OPEC production and secondly there was a steady stream of bearish developments on the macro-economic and demand fronts. Growing international trade tensions in general and the eruption of a fully-fledged US-China trade war also weighed on market sentiment. Interestingly, the marked downward tendency in prices in the third quarter of 2019 occurred despite declining US inventories and a significant apparent supply deficit.

Price surge following attacks on Saudi facilities proved fleeting: Initially, the attacks on Saudi Aramco's processing facilities on September 14 resulted in a price surge taking Brent to about $72/barrel. This, however, proved short-lived. By end September Brent was roughly back to the levels of around $62/barrel prevailing before the attacks. At first glance this appears a surprising outcome given the apparent scale of the damage to facilities responsible for processing around 6% of world oil production. The explanation appears to be a very quick response by Aramco in repairing the facilities and restoring production and a lack of retaliation by either the US or Saudi Arabia. The upward trend in non-OPEC output has also tended to support bearish market sentiment.

Subdued price trend in Q4: We look for a subdued price trend in the fourth quarter of 2019 subject to the caveat of no further attacks on oil facilities in the Gulf or major outages. This reflects our view that the market will be comfortably supplied over the balance of the year and that the lacklustre economic backdrop will continue to weigh on market sentiment. Our expectation is that Brent and WTI will trade broadly within the third quarter ranges, excluding the mid-September spike, of $56-66/barrel and $54-58/barrel respectively. For Brent and WTI our fourth quarter forecasts call for average price levels of $59.4/barrel and $53.7/barrel respectively. The implied 2019 yearly averages are $63.4/barrel for Brent and $56.2/barrel for WTI. These forecasts reflect downgrades from those given previously of $67.4/barrel for Brent and $60.2/barrel. This stems from the weaker than expected trend in the year-to-date and the anticipation of a well-supplied market in the fourth quarter.

2020

Broadly flat trend for prices in 2020: Our forecast of a modest supply surplus combined with a lacklustre macro-economic outlook globally continues to point to a broadly flat price trend for benchmark light crude prices in 2020. Our base case scenario for the price of Brent is as follows: Q1 $60.0, Q2 $61.5, Q3 $61.5, Q4 $63.0. The average for 2020 is $61.5/barrel, is significantly down on the previous forecast of $64.1/barrel reflecting lower carryover from 2019.

For WTI our 2020 quarterly scenario is as follows: Q1 $54.0, Q2 $56.0, Q3 $56.5, Q4 $58.5. The average for the year of $56.3 reflects a discount of $5.2/barrel to Brent. This we believe is about $1/barrel above spot pipeline costs from the Cushing tank farm to the US

Gulf Coast where crude attracts prices close Brent. The narrowing in the Brent-WTI spread between 2019 and 2020 from $7.2/barrel reflects the upgrading of the pipeline infrastructure in Texas which has diverted oil from the Cushing tank farm. Our new WTI forecast of $56.0/barrel is modestly below the $59.3/barrel given previously.

Interestingly, as of late October 2019 the backwardated forward curves for both Brent and WTI were showing a weaker picture than our price forecasts. The Brent forward curve shows a forward price for December 2019 and December 2020 deliveries of $58.5/barrel and $55.9/barrel respectively. The comparable prices for WTI are $53.3/barrel and $51.1/barrel. The apparent variance possibly reflects two factors. Firstly, our assumption that the OPEC+ production accord will be extended beyond March 2020 and secondly that US production growth could be somewhat slower than generally expected in 2020. Slower production stems from declining US drilling activity and well completions plus a slowdown in well productivity growth.

WILD CARDS

In common with other commodity markets, petroleum is subject potentially to a wide range of short-term wild cards and areas of uncertainty. We see the key issues facing the petroleum sector near term as being macro-economic, shale well productivity, Middle East tension, Venezuela and the OPEC+ production accord. Our views on each of these issues is as follows:

- **Macro-economics**: The key macro-economic question remains does the OECD economy in general in 2020 descend into recession or perhaps commence a prolonged period of sluggish growth/stagnation. The oil demand forecasts made by forecasting bodies such as the EIA, IEA and OPEC are based on an upturn, albeit modest, in world economic growth between 2019 and 2020. Given what we know about the world economy currently, this would appear optimistic. Indeed, the industrial sectors in the US and Europe would already seem to be flirting recession. Clearly, a recessionary rather than a slow growth scenario in 2020 would imply a looser supply/demand relationship than predicted by major forecasting bodies. A very soft petroleum price environment could ensue.

- **Middle East tension**: Volatile political relationships are an enduring feature of the Middle East. The relationship between Saudi Arabia and Iran has been close to breaking point for some time particularly over the latter's support for the Houthi regime in Yemen. Arguably it did break on September 14 with the latter's apparent attack on Aramco's facilities at Adqaiq and Khurais. Fortunately, no retaliatory military action was taken.

  Should another similar attack on Saudi Arabia be made either directly or via proxies, retaliation will possibly be hard to resist resulting in a conflagration in the Persian Gulf and the loss of oil and gas exports from the region. The loss might be equivalent to about 20% of world supply and could not be compensated from other sources. The upshot would be a stratospheric surge in oil prices. We believe, however, that the odds of such a scenario are fading for the moment, at least, given the recently announced partial cease-fire by Saudi Arabia in Yemen. President Trump has also signalled he is not interested in further entanglements in the Mideast and especially ones that could result in a surge in the price of gasoline in an election year.

- **Venezuela**: President Maduro is the great survivor. So far, he has successfully defied swingeing US financial and trade sanctions, civil unrest, a population exodus, attempted coups and plunging oil production. According to Juan Guaido, the Venezuelan opposition leader, oil production in the country is now down to 0.6mm b/d, massively below the levels of over 3mm b/d produced before Hugo Chavez's Bolivarian Socialist Revolution in 1999. The explanation is the continuing support of the military and of China and particularly Russia. If this support was to melt away, the Maduro regime would, in all likelihood, quickly collapse.

Clearly, any new regime would want to quickly restore production and doubtless would be supported in this endeavour by the US and Europe. This would however destabilise the global petroleum supply/demand relationship with potentially negative commodity price implications, particularly of the heavy grades, the mainstay of Venezuelan production.

- **US shale well productivity and production:** Declining shale well productivity has become a talking point in petroleum industry circles. While major players operating in the key shale and tight reservoir basins of the US suggest that the problem can be overcome there is a possibility that consensus production scenarios are too bullish. Significant shortfalls in production would be highly positive for oil prices. Note, the picture can easily be monitored with the aid of the EIA's weekly and monthly statistical publications. Alarmingly for the US petroleum industry Elizabeth Warren, one of the front-runners for the Democrat Presidential nomination is talking of banning fracking. Clearly this would have disastrous implications for US oil production.

- **OPEC+ production accord**: OPEC and a group of allies led by Russia have been implementing a policy of production restraint since January 2017. The current programme was implemented in January 2019 and is planned to continue through March 2020. According to Saudi Arabia, a decision on whether or not to extend the programme after March 2020 will be made at the forthcoming meeting in late November 2019. Anecdotal evidence would suggest that an extension will be agreed. A deepening of the current cutbacks is also a possibility.

  The soft demand backdrop and the potential for a price rout if production curbs are removed would seem to provide the underpinnings for restraint. Such a policy, however, provides a price umbrella for the US and others which has led to speculation in some quarters of late that the optimal strategy for OPEC producers at this juncture would be to boost production. The aim would be to push down prices thereby forcing lower development activity in the US and elsewhere. Such a policy was adopted by OPEC for a while prior to 2017. The result was light oil prices plunging to $30/barrel or less.

EXHIBIT 13: BRENT 2009-2020 QUARTERLY PRICES ($/BBL)

	Q1	Q2	Q3	Q4	Average
2009	45.1	59.4	68.4	75.0	62.0
2010	76.8	78.6	76.4	86.9	79.7
2011	104.9	116.8	109.1	109.3	110.0
2012	118.7	108.7	109.8	110.9	112.0
2013	112.8	102.9	110.0	109.4	108.8
2014	107.9	109.8	102.2	76.4	99.1
2015	53.9	61.7	50.2	43.7	52.4
2016	33.9	45.6	45.8	49.3	43.7
2017	53.7	49.7	52.1	61.5	54.3
2018	66.8	74.8	75.0	68.3	71.2
2019e	63.2	68.9	61.9	59.4	63.4
2020e	60.0	61.5	61.5	63.0	61.5

Source: EIA and Allenby Capital

EXHIBIT 14: WTI 2009-2020 QUARTERLY PRICES ($/BBL)

	Q1	Q2	Q3	Q4	Average
2009	43.2	59.7	68.1	76.0	61.8
2010	78.8	77.9	76.1	85.2	79.5
2011	93.9	102.3	89.5	94.0	94.9
2012	103.0	93.3	92.2	88.2	94.2
2013	94.3	94.1	105.8	97.6	98.0
2014	98.7	103.1	97.6	73.2	93.2
2015	48.5	57.9	46.4	41.9	48.7
2016	33.2	45.4	44.9	49.1	43.2
2017	51.8	48.2	48.2	55.4	50.9
2018	62.9	68.1	69.7	59.6	65.1
2019e	54.8	59.8	56.4	53.7	56.2
2020e	54.0	56.0	56.5	58.5	56.3

Source: EIA and Allenby Capital

EXHIBIT 15: BRENT AND WTI PRICE LONG-TERM TRENDS

$/bbl	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019e	2020e
Brent	72.7	97.7	62.0	79.7	110	112	108.8	99.1	52.4	43.7	54.3	71.2	63.4	61.5
WTI	72.2	99.8	61.8	79.5	94.9	94.2	98	93.2	48.7	43.2	50.9	65.1	56.2	56.3

Source: EIA and Allenby Capital

THE HIGH-VOLUME VEHICLE ELECTRIFICATION ERA BEGINS

PETROLEUM INDUSTRY'S LARGEST MARKET UNDER THREAT

Highway transportation the largest petroleum market and the main source of growth: Long-term, the greatest threat to petroleum demand is vehicle electrification. The dominance of gasoline and diesel internal combustion engines as the power source of choice for on-highway vehicles has provided the petroleum industry with its largest market over many years. Presently, highway transportation fuels account for about 45% of total petroleum usage globally while transportation's weighting overall is around 60% (over 70% in Europe and North America). Significantly, highway transportation has accounted for over half of the growth in petroleum demand for the past ten or more years. Broadly, gasoline and diesel account for around 95% of highway transportation energy sources with the balance comprising ethanol, bio-diesel, CNG (compressed natural gas) and electricity.

VW ID3 MEB LAUNCHED

Beginning of the high volume EV age: A major event along the road to vehicle electrification has recently been announced by Volkswagen, which probably has the most ambitious vehicle electrification programme of any automotive OEM presently. The event was VW's launch at the Frankfurt Auto Show of the ID3 (similar in package to a VW Golf or Ford Focus) BEV (battery electric vehicle). We believe this will be seen in retrospect as the beginning of the high-volume electric vehicle (EV) age.

ID3 price of around $30,000: Unlike the Tesla product line which until the Model 3 focused on premium vehicles, the ID3 will be competing much closer to the middle of the market. For a base version the price will be around $30,000 pre-incentives, which is competitive for a BEV. For large premium Audi and Porsche BEV's VW has developed the PPE (Premium Platform Electric) platform. The first application of this has recently been launched in the form of the Porsche Taycan, a powerful four-door coupe similar in package to the gasoline Porsche Panamera or indeed the Tesla Model S. Not surprisingly, the price point of the Taycan is completely different than the ID3 at around $145,000.

Production start-up at Zwickau in 2020 at 100,000-150,000: The ID3 is the first of five derivatives to be launched based on VW's modular MEB (a German acronym meaning modular electric-drive) platform developed over the past three or four years for high-volume electric vehicle applications. Production will commence at Zwickau, central Germany, in 2020 at a rate of 100,000-150,000 pa. The capacity of the plant is about 330,000 units/pa, according to press reports. This is very much in line with the automotive mainstream. VW plans to commence operations at several other dedicated electric vehicle plants in the US, China and Europe by 2022. By this time the plan is to produce over 1m BEVs/pa on the MEB platform.

VW MEB LICENCE AGREEMENT WITH FORD

Ford to introduce a BEV in Europe in 2023 based on MEB platform: Importantly, VW also has a licence agreement with Ford for use of the MEB platform and is seeking other partners to help spread the costs of what has been reported as a $10bn development programme. Note here the MEB offers highly flexible chassis technology and can be adapted relatively easily to the needs of different OEMs. Ford is reported to be looking to introduce at least one MEB-based BEV in Europe by 2023. Recently in Europe it has launched its PHEV (plug-in hybrid electric vehicle) Transit van, the first of its type in the region. Significantly, Ford and VW have announced a joint van and pickup truck development programme outside North America. Ford is leading this programme.

Ford scheduled to launch a Mustang inspired BEV on November 17 using an inhouse platform: For its North American operations Ford has its in-house BEV development programme. The first results of this will be revealed in the US on November 17, 2019 with the unveiling of a Mustang inspired crossover. According to press reports this will probably be called the Mach-e. The reports also suggest the new Ford will have a highly competitive range of 600 km.

ELECTRIFICATION DRIVEN BY TIGHTENING CO2 STANDARDS AND FINES

Punitive fines for non-compliance: All major auto OEMs have their own vehicle electrification plans with some more advanced than others. In Europe, at least, the key driver is tightening CO2 emissions regulations on gasoline and diesel engines. For passenger cars the 2021 EU regulations call for a CO2 target of 95 g/km on average across the auto industry. This is about 22% under current emissions of around 121 g/km and implies fuel consumption (gasoline) of 4.11/100 km or almost 70 mpg. Importantly, the regulations call for a further cut of 38% to 59 g/km by 2030. The enforcement mechanism is via a system of fines. In the case of the 2021 target a fine will be levied of €95 for each g/km over the target of 95 g/km multiplied by unit sales. Clearly, the financial penalties have the potential to be punitive in the event of serious non-compliance.

PARTIAL ELECTRIFICATION VIA COST EFFECTIVE MILD-HYBRID 48-VOLT TECHNOLOGY

Initially application of 48-volt mild hybrid technology: The auto industry believes that the emission targets are impossible and/or too costly to achieve with existing internal combustion technology. There is, therefore, no alternative to partially or wholly electrifying the fleet within a short lead time. Initially this can be achieved to a large extent by using relatively low-cost 48-volt mild-hybrid technology. This is capable of reducing fuel consumption by 10-15% for an installed cost of about $500 and no chassis redesign work.

Ultimately no alternative to adding BEVs to the sales mix: As emission regulations tighten, however, there will be no alternative to adding large numbers of BEVs to the sales mix. The question then becomes just how quickly the market is prepared to make the switch from internal combustion engine to electric vehicle propulsion systems. While BEV’s are suitable for short-distance commuting, particularly where re-charging facilities are available at both ends of a journey, they are not yet viable for those wishing to travel much more than 200-300 km/day.

RANGE AND RECHARGING TIMES STILL AN ISSUE ALONG WITH BATTERY LIFE

Limited range and long recharging times remain major drawbacks of BEVs for medium to long range applications. Note here that the times often quoted for rapid recharging of 30 minutes or so are only for an 80% charge. Full 100% recharging will take significantly longer than 30 minutes, a major disadvantage for long-distance driving.

Another drawback of BEV’s that is often over-looked is battery life. Users (particularly in China) quite often report a deterioration in performance at relatively low mileages. Interestingly, VW’s warranty on the ID3 only covers 70% of usable capacity for eight years or 160,000 km. Remember that batteries account for approaching half the cost of a BEV so we could be looking at around $15,000 to replace a battery even on a low-cost BEV. Modern internal combustion engines have a life to major overhaul of significantly over 160,000 km.

MAJOR POWER DISTRIBUTION AND GENERATION INFRASTRUCTURAL ISSUES

In addition to the product drawbacks, widespread use of BEV’s raises the question of electrical power generation and distribution infrastructure. Substitution on a large-scale of diesel and gasoline by electricity will undoubtedly require a major upgrade in electrical power distribution capacity, a conclusion that is particularly poignant assuming intensive use of rapid charging facilities. An increase in electricity consumption sufficient to replace existing diesel and gasoline usage will, in all probability, require substantially more power generation capacity, although this is denied by the environmental lobby. The claim is that this can be obviated by night time recharging. This is totally implausible in our view given the need in many instances to recharge during peak hours.

Re-charging station bottlenecks: Another point that is overlooked on the infrastructural front is that long recharging times are likely to create bottlenecks at recharging stations. Throughputs of vehicles will be considerably less than at traditional gas stations. Recharging times could therefore in practice be significantly longer than indicated.

Consensus forecasts call for BEVs and PHEV's to account for about 15% of the global light vehicle sales mix by 2025. This would imply sales of 16-17m units assuming global industry sales overall of 109m units. The balance of the mix will probably mainly be mild 48-volt hybrids and other hybrids in our view. We believe the BEV and PHEV share of the mix could increase to around 30% by 2030. From a fuel consumption perspective, however, new vehicle sales are only part the story in terms of emissions.

A large park of internal combustion powered vehicles is likely into the 2030s. Even with an increase in the BEV and PHEV share from 2% currently to 30% in 2030 there would still be a large park of internal combustion engine powered vehicles bearing in mind typical lives of 15-20 years. In practice, therefore, although the growth in gasoline and diesel usage is likely to tail away in the early 2020s, peak demand globally might not occur until the second half of the decade or even the first half of the 2030's. The question then arises as to what action will be taken by the politicos if this trajectory does not coincide with their emission objectives. Will they introduce a compulsory scrappage programme possibly without compensation?

TOYOTA POISED TO SHOW-CASE SOLID-STATE BATTERIES IN A PROTOTYPE VEHICLE

The holy grail for vehicle battery technology-----: Solid-state battery technology is the holy grail for electric vehicles. Conventional rechargeable battery cells contain a cathode typically made from a lithium-cobalt compound, a graphite anode and a liquid electrolyte which separates the two electrodes, thereby helping prevent short circuits. The electrolyte facilitates the electrical charge flowing between cathode and anode and vice-versa on discharge. The drawbacks are low energy density which limits range in vehicle applications and a propensity for fires due to high operating temperatures and the flammability of the liquid electrolyte. By contrast, solid-state battery cells use a lithium anode and a ceramic electrolyte. The former substantially raises energy density while the latter minimises the risk of fire.

------given the potential of solid-state to double range and drastically reduce re-charging times: Because of their higher energy density, solid-state battery cells have the potential to at least double driving range and reduce recharging times to a matter of minutes. Very approximately, we could be looking at an increase in range from about 500 km (300 miles) with conventional Li-ion batteries to 1,000 km (600 miles). The application of solid-state technology has been severely constrained owing to technical challenges in high-volume manufacturing. This results in a hefty cost penalty and unacceptably slow production rates by automotive industry standards compared with conventional Li-ion battery cells.

Toyota looking to introduce a solid-state battery prototype in 2020 and commence mass-production in 2025: For some time, it has been known that Toyota has an advanced solid-state battery research and development programme. Indeed, within automotive circles their programme is widely considered to be the most advanced. This would appear to be confirmed by a statement on October 22 that Toyota is planning to unveil a prototype vehicle using solid-state battery technology based on its e-Palette platform for the 2020 Olympics in Tokyo. Significantly, however, Toyota has stated that it does not expect to enter mass-production with the technology before 2025.

Others are also seeking the holy grail: Other automotive OEM's such as General Motors, BMW, Daimler Benz and Volkswagen are all known to be undertaking solid-state battery research and development programmes. However, given the technical challenges involved in producing solid-state batteries at high volumes, the widespread application of the technology would appear unlikely before 2030. It also needs to be remembered that vehicles using solid-state technology will initially, at least, probably sell at a substantial premium to those using conventional Li-ion battery technology. Given the long development lead time required, solid-state battery technology may not become a serious threat to diesel and gasoline fuelled internal combustion engines until the 2030's in our view. An early breakthrough in solid-state battery technology would have profoundly negative implications for the petroleum industry.

Disclaimer

Research Disclosure

Peter Dupont is the author of this research recommendation. Peter is employed by Allenby Capital Limited as an Equity Analyst. Unless otherwise stated the share prices used in this publication are taken at the close of business for the day prior to the date of publication. Information on research methodologies, definitions of research recommendations, and disclosure in relation to interests or conflicts of interests can be found at www.allenbycapital.com.

Allenby Capital, 5 St Helen's Place London EC3A 6AB, +44 (0)20 3328 5656, www.allenbycapital.com