Vol. 1 Issue 2

March 2019

CRUDE PRICE RALLY ON US-CHINA TRADE DEAL TO BE LIMITED

Benchmark crude futures averaged 7% higher in February compared with January, continuing to be buoyed by growing optimism over a US-China trade deal. However, by early March, the rally had stalled.

The path to a trade agreement has been tough and the negotiating teams have been working through major hurdles right into the final stages, especially around the structural changes Washington has demanded of Beijing and the implementation mechanism. However, the deal looks certain and as we wrote this report, was expected to be signed by presidents Donald Trump and Xi Jinping on March 27.

Meanwhile, the US Federal Reserve has continued to reaffirm its patient and cautious approach, after first signalling its dovish pivot in December, following a spate of interest rate hikes that had progressively unnerved investors through 2018.

Global stock markets have cheered both developments and by the end of February, had inched close to levels seen at the beginning of last October, before the start of the financial markets turmoil (see chart on page 7).

However, the rebound in oil has paled in comparison, and we expect it to remain so.

We believe the economic tailwinds anticipated from the US-China rapprochement, especially for the latter, the world's second-largest oil consumer and the biggest contributor to demand growth, have already been largely priced into crude. It is also becoming clear that the trade deal between the world's two largest economies is no silver bullet for the global economic growth deceleration forecast for 2019 and 2020.

China is facing a "graver and more complicated environment" and needs to get ready for "tough struggle" ahead, Premier Li Keqiang warned the inaugural session of the country's annual session of the National People's Congress on March 5.

Beijing has officially lowered its 2019 economic growth target to 6.0-6.5%, as widely anticipated. That follows last year's 6.6% GDP growth, which was the slowest since 1990. The latest stimulus measures from Beijing are not expected to jump-start the economy like the debt-fuelled boom after the Global Financial Crisis.

With the gloomy shadow of the US-China tariff war lifted, the oil market is turning its focus back to fundamentals. The overall supply-demand picture looks balanced for now, which is neutral for market sentiment and points to rangebound crude prices. However, geopolitical threats to oil supply have stacked up in recent months.

Venezuela tops that list, with its entire crude production of just over 1 million b/d potentially at risk from US sanctions against PDVSA imposed on January 28 and the possibility that opposition leader Juan Guaido's political challenge to embattled President Nicolas Maduro will disintegrate into a civil war. So far, it is a political impasse in Caracas, and the oil market is not factoring in the worst-case scenario.

In fellow OPEC producer Nigeria, incumbent Muhammadu Buhari clinched a second term in a controversial presidential election on February 23. The oil-rich southern states voted for his main opponent Atiku Abubakar, and may see a resumption of militant attacks on infrastructure, causing major, albeit erratic, disruptions to crude production.

OPEC has made a strong start to its pledged production cuts of 812,000 b/d, with the 11 members that agreed to lower quotas starting January 1 achieving 100% compliance in February, helped by Saudi Arabia cutting deeper than its commitment. With the remaining three members — Libya, Iran and Venezuela — under-delivering, OPEC will need to be cautious not to inadvertently over-tighten the market, as happened last year.

OPEC shrugged off a tweet from President Trump on February 25, exhorting the group to "take it easy" and not push prices too high. Saudi Energy Minister Khalid al-Falih stressed that OPEC+ was committed to draining surplus global oil stocks, though it would take a "slow and measured approach". That strategy will be tested in the coming months. The fact that OPEC+ is meeting more frequently than its earlier biannual schedule — the next ministerial is set for April 17-18 — is a good starting point.

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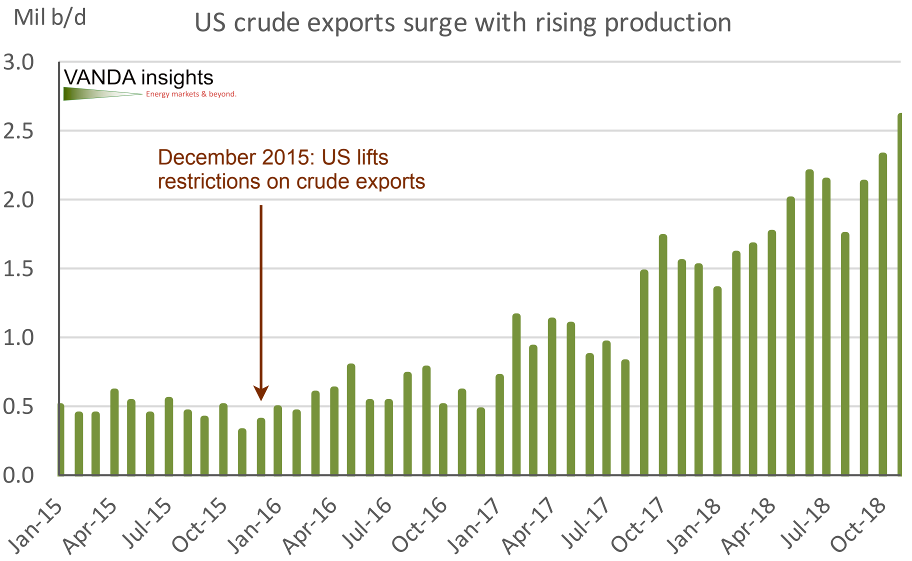
WTI HOUSTON REFLECTS US EXPORT ECONOMICS



Source: US EIA. Latest monthly data available is up to November 2018.

As a rising tide of crude from the Permian begins to flow to refineries and export terminals along the US Gulf Coast, the market needs a reliable and transparent value for the barrels at oil terminals on the USGC.

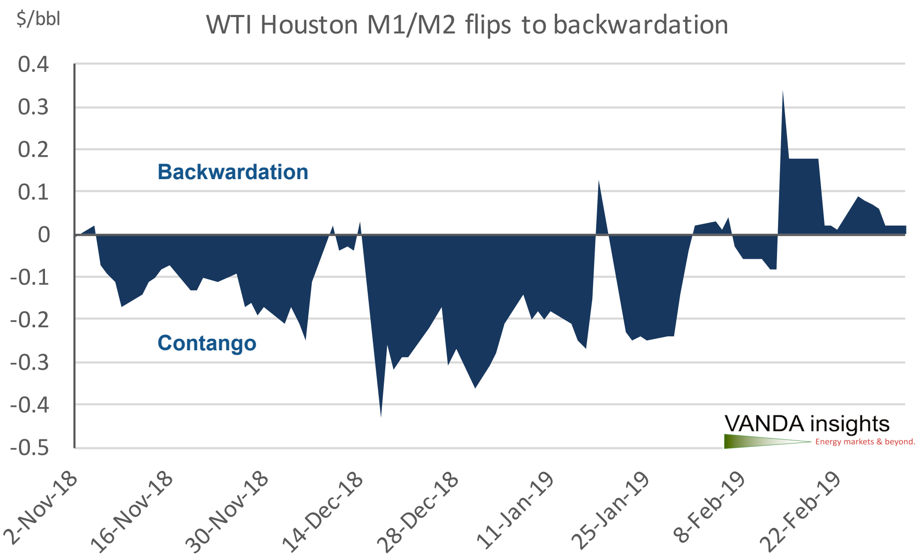
The recently-launched WTI Houston crude futures contract aims to serve that purpose.

The long-established NYMEX WTI futures, while still popular with physical market players as well as speculative traders, more accurately reflects the supply-demand fundamentals at the contract's delivery point of Cushing in Oklahoma. Its values come under pressure and its discount to Brent widens whenever Cushing inventories build up, as has been the case once again since September 2018.

Crude stocks at Cushing more than doubled between September last year and February, according to data from the US Energy Information Administration.

WTI's discount to Brent on a front-month futures basis widened to an average of $9.10/barrel in February, versus $6.57/barrel last August.

The spread between the front two months of WTI (Cushing) futures has been consistently in double-digit contango since October 19 last year. Meanwhile, the corresponding spread for Brent futures has been either in slight backwardation or a mild contango since mid-January, when crude prices began to rally on the back of optimism over a US-China trade deal.



Source: CME

Contango, a market state in which barrels for prompt delivery are priced lower than those further out in time, typically reflects an oversupplied market, and backwardation is the opposite state.

A look at CME's WTI Houston crude futures shows a close correlation and a tighter spread with Brent.

The contract, launched in November 2018, reflects barrels delivered at Enterprise's ECHO, Genoa Junction and Houston Ship Channel terminals in Houston, Texas.

The M1/M2 spread in WTI Houston futures ranged between a contango of 43 cents/barrel and a backwardation of 34 cents between last November and the end of February.

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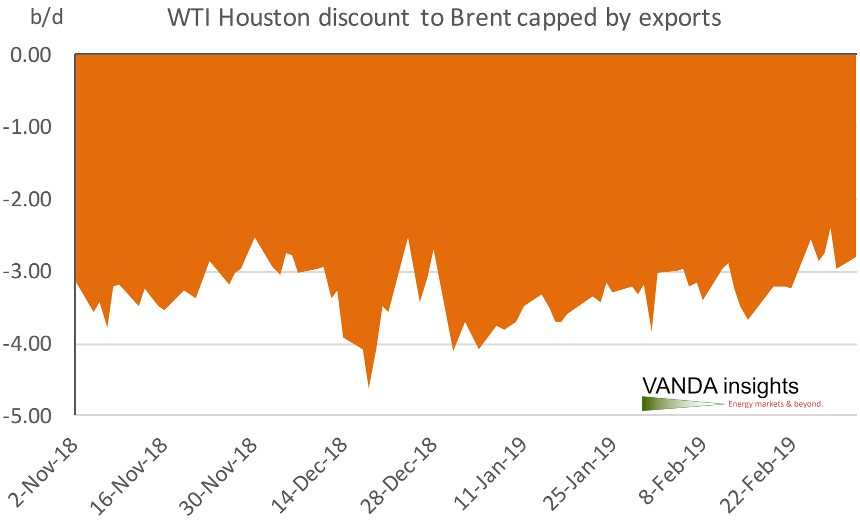


The spread was in backwardation through the second half of February, coinciding with a spike in US crude exports to an all-time weekly high of 3.6 million b/d over the period of February 11-15.

WTI Houston traded at an average discount of $3.08/barrel to Brent on a front-month futures basis in February, versus a discount of $3.56 in January.

This spread should tighten as US crude exports continue to strengthen in the coming months, as expected.

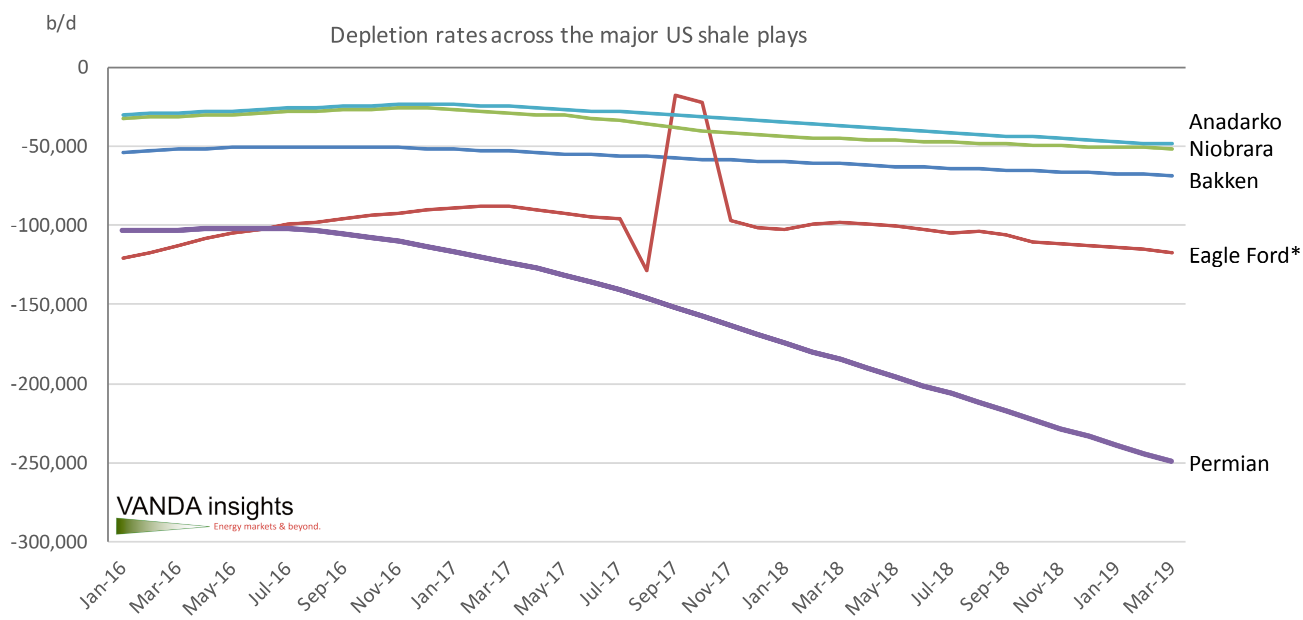
Source: CME (WTI Houston), ICE (Brent)

BEWARE SHALE'S SHORT TAIL

While factoring in global supply expectations for 2019, it is important of looking beyond the dazzle of the unprecedented surge in US crude production, especially the spectacular annual jump of 1.6 million b/d in 2018 to an average of 10.95 million b/d.

Tight oil from shale plays averaged about 7.31 million b/d, accounting for two-thirds of the country's total crude production last year, with the rest being conventional output.

A slowdown in activity in the US shale patch through the fourth quarter of 2018, prompted by plummeting crude prices, may not reverse anytime soon, especially as producers remain uncertain of the extent and sustainability of the recent price recovery and under pressure from shareholders to keep capital expenditure within cash flow. Most independents have lowered their 2019 planned capex from 2018.



*Source: EIA Drilling Productivity Report, Vanda Insights analysis *Anomalous behaviour in Eagle Ford around August and September 2017 is due to the impact of Hurricane Harvey-related shutdown of wells in the region. Figures for February and March 2019 are EIA projections.*

A recent deceleration in production growth rates in the Permian, a region that accounts for 48% of the oil produced from the major US shale basins, is likely to sustain until new pipeline capacity comes on stream towards the end of this year to help relieve the current transportation bottleneck.

In December, the Permian saw the first month-on-month reduction in oil rig count since May 2016, according to the EIA's latest monthly Drilling Productivity Report, issued in February. The number of rigs drilling in the Permian has continued to decline through January and February.

Total oil rig count in the five major US shale regions — Bakken, Eagle Ford, Niobrara, Permian and Anadarko — had slipped to 815 by the end of January from a peak of 828 in November.

Not surprisingly, the EIA is forecasting the smallest month-on-month rise in oil production of around 84,000 b/d from the country's seven shale regions in March, around 8.40 million b/d.

The monthly rate of growth has been steadily dropping since hitting a high of about 281,350 b/d last September.

A drop in shale rig count typically shows up in lower production numbers within two months.

Why the rig count is critical

The sharp depletion rates characteristic of the US shale sector make the pace at which new rigs are deployed a particularly critical component of sustaining production growth.

The 1.5 million b/d annual jump in average oil production from the US shale plays in 2018 is well-known. What is less known, is the amount of production that was lost from older wells that went dry that year: A whopping 5.55 million b/d!

In other words, shale producers achieved a **net** increase of 1.5 million b/d last year after offsetting a natural decline of 5.55 million b/d, according to our analysis of the EIA data.

The annual natural decline in 2016 and 2017 was about 3.8 million b/d and 4.1 million b/d respectively. That means the amount of production being lost from older wells, also known as legacy decline, is growing in tandem with rising output.

And it is a testament to the rate of decline seen in shale that a well is considered "new" only up to its first month of production.

Shale producers thus have to drill a minimum number of wells each month just to offset the inevitable loss of output from the older wells (unless they are dipping into their inventory of drilled but uncompleted wells, or DUCs, which is not the case with the Permian).

The rate of depletion as an absolute number is the highest in the Permian and also rising faster compared with the other shale plays, which is to be expected, given that it is consistently notching the strongest growth in output.

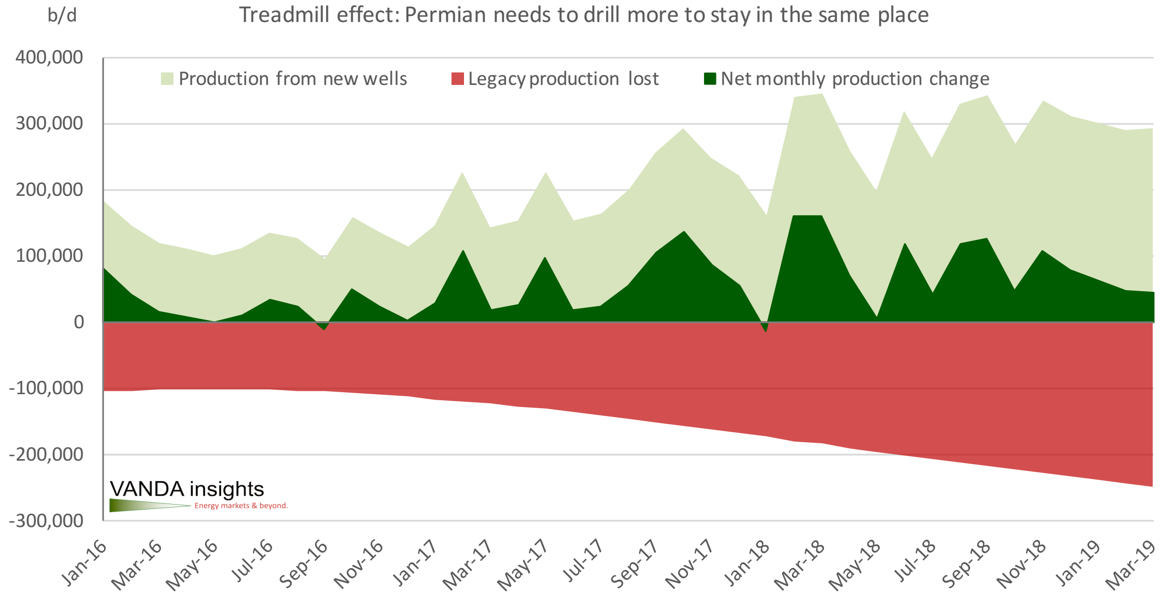
However, the rate of depletion as a **proportion** of the Permian's oil output has also been steadily rising, as the table below, derived from EIA raw data, shows. March 2019 figures are the agency's latest projections, data for the previous months is actual recorded numbers.

With one rig delivering about 598 b/d of production from new wells in in the Permian in February, of the 466 rigs deployed in the basin that

month, 409 would have been needed just to counter the legacy decline, or in other words, sustain the production level achieved in January.

Permian's vital statistics			
Month	Avg daily production (mil b/d)	Avg daily depletion (mil b/d)	Depletion as % of output
Mar 2016	1.983	0.103	5.20
Mar 2017	2.269	0.124	5.45
Mar 2018	3.169	0.185	5.83
Mar 2019 (e)	4.024	0.249	6.19

As the graph below shows, as production from new wells in the Permian (light green area) declines, while depletion rates (red area) continue to rise, the net increase in output (dark green area) is shrinking.



Source: Data from EIA's Drilling Productivity Report, extrapolated by Vanda Insights. Feb and Mar 2019 figures are EIA's latest estimates, while data for earlier months is actual production and depletion numbers.

Combatting natural decline a costly affair

In 2018, about 54% of US producers' capital spending went into drilling new wells to offset the steep decline from older wells. By 2021, that ratio is expected to jump to 75%, Paal Kibsgaard, CEO of major oil services provider Schlumberger, said in the company's Q4 earnings call in January.

He called it the "unavoidable treadmill effect" of shale.

Aside from the steep decline rates that will become costlier and harder to combat, there are other challenges. With an increasing number of wells being drilled in the shale basins, producers are steadily moving out of the most productive core of their acreages.

Meanwhile, problems of interference between "parent" and "child" wells in infill drilling persist, and the benefits of drilling longer lateral wells and injecting more proppants are starting to plateau.

The EIA projected a 1.46 million b/d annual rise in overall US crude production in 2019 to 12.4 million b/d in its February Short-Term Energy Outlook. That's slower growth than the 1.6 million b/d achieved in 2018, but could be revised lower, still.

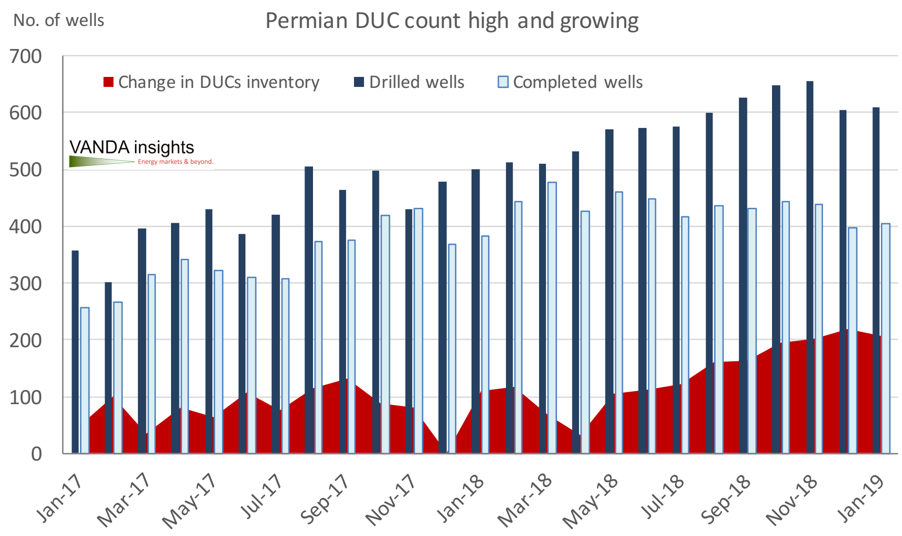
The EIA's 2020 output forecast calls for a rise of about 790,000 b/d over 2019. The growth incline is thus clearly easing.

Remember the "hypermania" over the Permian's prospects during CERAWeek, a major annual industry conference in Houston, in March 2017?

Some industry executives had suggested at the time that the rising star of the US shale industry, which was pumping around 2.27 million b/d at the time, could climb to as much as 8-10 million b/d in a decade or so.

The expectations have moderated considerably since then. Total production from US shale regions — not the Permian alone — "will probably" climb to about 10 million b/d by the middle of the next decade and then flatten out, John Hess, CEO of Hess Corp., told the World Economic Forum in Davos in January this year.

A Permian supply flood looks unlikely



Source: EIA Drilling Productivity Report

The expected start-up of around 2 million b/d of new oil pipeline capacity from the Cactus II, EPIC and Gray Oak projects, connecting the Permian to refineries and export terminals on the US Gulf Coast by the end of 2019, is prompting renewed attention to the DUCs amassed by producers in the basin straddling Texas and New Mexico.

The DUCs, or wells waiting to be put into production, numbered just over 4,170 in the Permian at the end of January, and accounted for around half of the total DUCs in the five major shale plays, according to EIA data.

Starting in the second half of 2018, Permian producers have been leaving on average every third well they drill uncompleted, for future production.

A simultaneous move by all Permian producers to put their huge inventory of DUCs into production would be fraught with problems.

Even if the requisite pipeline takeaway capacity is available, a spike in the hydraulic fracturing activity would cause cost inflation as well as bottlenecks in terms of proppants, fracking crews, fracking equipment and other supporting infrastructure.

Market economics would ensure that any sudden and big jump in production gets streamlined. If crude prices are supportive enough when the DUCs start to come on stream in large numbers, a spurt in production is bound to exert downward pressure on them, reducing the incentive to pump more.

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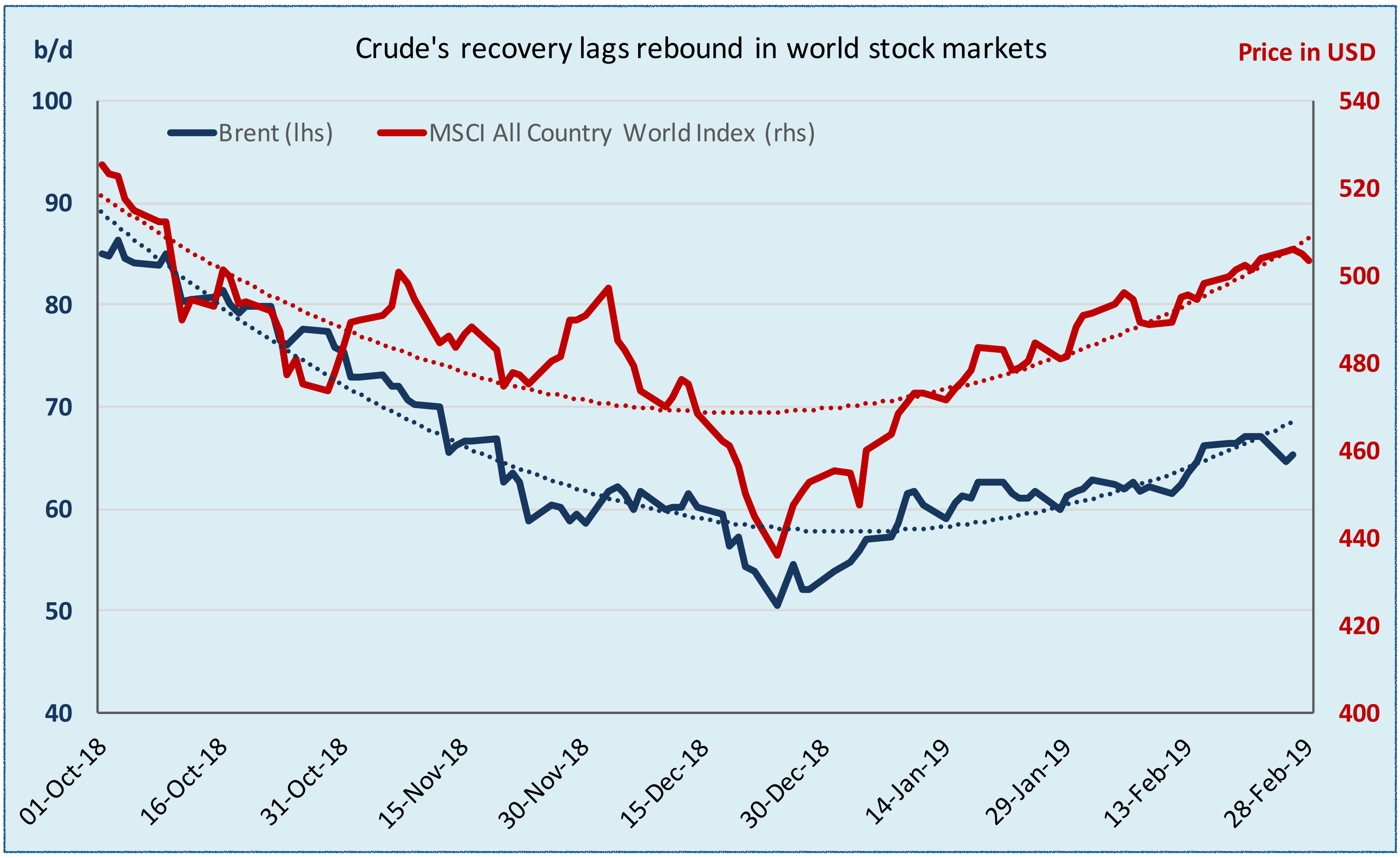

Source: ICE (Brent), Marketwatch (MSCI All Country World Index)

Crude slid in lockstep with the global equity markets between October and December last year, as the global financial markets turmoil sparked a sell-off across risk assets. The risk-off sentiment was triggered by a combination of signs of strain in the Chinese economy and other parts of the world, worries over rising corporate borrowing costs as the US Federal Reserve remained on an aggressive interest rate-hiking path, and despair over the US-China trade war (negotiations to end it were in a limbo, until being revived in January this year, after Trump and Xi met and agreed a 90-day truce on December 1).

However, as the chart above shows, though Brent has steadily recovered from its December 24 nadir, it remains well below its early-October levels and the rise so far this year is no match for the rebound in the stock markets. The MSCI All Country World Index, which is a good representative of global equities by virtue of capturing 23 developed markets and 24 emerging markets, was only 4% below its October 1 value on the last day of February.

Brent is highly unlikely to retrace its way to the $80s (the benchmark settled at a four-year high of $86.29/barrel on October 3) because in addition to coming under pressure from the financial market jitters, through the last two months of 2018, crude was also unwinding the “fear premium” that had built up on account of the US sanctions against Iran’s oil sector. Once the US granted more generous-than-expected waivers to importers of Iranian crude just ahead of the start of its sanctions on November 5, worries over extreme supply tightness melted away. Though hedge funds and other major speculators have been gradually returning to buy Brent and WTI futures contracts since mid-January after a big sell-off through Q4, their net length, an indication of bets on rising prices, remains at a fraction of the all-time highs reached in April 2018.