A review of the impact of Covid-19 corona virus on the oil sector

Balancing the downturn—how the oil sector, from major producers to refiners, is facing a temporary dip in demand of up to about 25 mn bpd (25%) as a result of virus containment measures, and how it is balancing this by filling storage and cutting supply, amid low and volatile oil prices.

A large portion of oil demand has been temporarily erased by measures related to the Covid-19 virus, and parts of the industry could need life support to ensure their survival through this period as prices tumble. The demand reduction must be balanced by lower supply, and the OPEC/non-OPEC agreement in mid-April taking 9.7 mn bpd off the market goes some way toward this. However, it was not enough, and subsequent falls in the oil price, particularly for WTI as storage fills, are leading to widespread shut-ins for commercial reasons or because a buyer simply cannot be found. It is currently unclear how deep these cuts will be, but another 5 to 10 mn bpd may need to go offline for a month or two at least to get close to balancing the market; with a significant portion of this from the North American onshore.

March and April have been tumultuous months for the oil markets. Prices have continued to fall, under pressure from falling demand associated with coronavirus travel restrictions and lockdowns, as well as a surge in OPEC supply. WTI dropped as low as minus $40/bbl for May delivery at the close on 20 April, albeit temporarily for technical reasons,¹ and Brent has fallen to the low $20/bbl (see Figure 1). This was despite the biggest ever agreed cut to crude supplies of 9.7 mn bpd, or almost 10% of the entire market, put in place by OPEC and an extended group of oil producers on 12 April. The cuts involve more countries than ever before, and while Mexico had been an early objector, its state company, Pemex, has since cut on commercial grounds.

Production cuts will have to eventually match or exceed the demand reductions to bring the market back into equilibrium, and the subsequent price falls were judgment that the market did not consider 9.7 mn bpd nearly enough. US President Trump had called for 15 mn bpd, and OPEC-plus had, in return, called on other producers to cut by at least 5 mn bpd. Meeting around the same time, G20 energy ministers promised to work together to stabilize oil prices, but did not make any specific commitments on production restrictions—leaving the cuts to market forces, which could take out well over 5 mn bpd (see non-OPEC-plus supply cut section below), according to latest (late April) estimates.

The OPEC-plus decision to cut came after a supply free-for-all in March, in which Saudi Arabia saw an opportunity to gain market share at the expense of lower cost producers after Russia failed to go along with cuts to balance the initial impact of Covid-19. But pressure from the United States (which still has considerable clout in Saudi Arabia due to the strong military support it provides), and the sheer scale of the collapse in demand, persuaded the Saudis and Russians back to the table.

But the pullback and attempt to balance the market were insufficient, even before the issue of compliance. This is partly due to the earlier supply surge, but mostly it is the dramatic crash in demand—which, with over a third of the global population under some form of lockdown, has fallen more sharply than ever before (see demand section below). The degree to which crude prices fall and their duration at low levels will be key in determining how much additional production gets shut in for commercial reasons. High-cost, unhedged output will be first to go, or that without easy access to storage or wider markets, with the Atlantic Basin likely to be worst affected.

The split of state-imposed cuts to cuts made on commercial/logistical grounds is not yet clear, but likely to end up around 60:40. The United States is expected to see a sharp fall, along with high-cost production in the Canadian tar sands, the North Sea (see non-OPEC supply section below) and even in countries like India, where Cairn has said it will cut expenditure and output. Even some OPEC members will see commercially driven cuts of this sort. Nigeria, for example, appears to be having problems selling March and April loadings, leaving multiple vessels without buyers, making shut-ins inevitable.

Because of high freight rates (due to a ballooning of floating storage and recent supply surge) and limited options to market, it is US onshore shale output, along with light sweet grades in the Atlantic basin that are
being hit hardest—as illustrated by the weakness of WTI and Nigerian situation—along with any other grades that compete with Saudi supply. Saudi Arabia remains the world’s lowest cost producer (at about $8/bbl) and has aggressively cut official selling prices (OSPs) in key markets in Asia and Europe in order to displace competing grades, such as Russian Urals in Europe and US light sweet shale oil and other Atlantic basin grades (including Nigerian and Angolan) in Asia.

With Saudi Arabia committing to the largest share of the OPEC-plus cuts (alongside Russia) through May and June (see OPEC-plus supply cut section below), its subsequent price discounts into Asia and Europe are intended to put pressure on other suppliers to cut prices and/or volumes further, pushing them to the limit and hopefully knocking out some higher-cost production, from which it can absorb market share once demand recovers.

Saudi crude flows to the United States are also up sharply, provoking calls for import bans or tariffs on crude imported into the United States to protect local producers. Refiners only have room for reduced deliveries, so some imported or local supply is having to be canceled or deferred. If too many US companies go under as a result of this Saudi competition, those arguing in Washington for a reduced military presence in the Gulf, largely in support of Saudi Arabia, will gain ground—something Saudi wants to avoid while still recovering market share it has lost since 2017; so it is still a balancing act for them. Whiting Petroleum, a major oil and gas producer in the Bakken Shale and Denver-Julesburg Basin, was the first US independent to file for bankruptcy in late April, and more are expected.

Saudi Arabia should be able to maintain this pressure for a while, given its low-cost production. However, it also requires among the highest oil prices to balance its books (about $80/bbl) and has few alternative sources of revenue. Russia requires a lower price of around $40/bbl but has been hard hit as prices fall below $25/bbl—especially in key markets where Saudi OSPs have been most heavily discounted. Non-OPEC producers, on the other hand, do not rely on oil revenue, and may be willing to support the sector temporarily during the downturn—and there have been indications to this effect in Asia and the United States. This could prevent much of the high cost oil being lost, leaving the market unable to clear without deeper cuts from OPEC-plus or less resilient/interventionist non-OPEC sources.

One support option being considered in the United States is a lending program for oil companies, which could provide essential cash to as many as 50% of the largest 60 independent US oil producers, which are likely to need it in order to stave off bankruptcy, according to lawyers Haynes and Boone. Major oil companies, on the other hand, remain relatively cash-rich, sheltered by their extensive mid and downstream sectors. They are likely to absorb the impact of low prices through capex and probably dividend cuts. For example, Exxon has reduced capex by 30%, similar to other majors, and Equinor cut its Q1 dividend by two-thirds (BP has not cut; others yet to announce).

There has even been pressure in the United States to join OPEC-plus in its top-down cuts. But while United States cuts were implicit in the mid-April deal, US president Trump did not say whether Washington would impose any on US producers, beyond those they are imposing on themselves for commercial/logistical reasons. At a state level, the Texas Railroad Commission (TRC) is still considering a top-down approach, encouraged by larger Permian Basin players such as Pioneer Natural Resources and Parsley Energy, although the majors and many other companies are against it, and there are considerations around US anti-trust laws that raise questions over the legality of such a move. The TRC used to enforce cuts and acted as an OPEC-style market
1 | DEMAND DECLINE—OVERALL FORECASTS

The scale of the demand decline due to the lockdowns and travel bans is so far difficult to quantify, with estimates ranging from 16 mn bpd to over 25 mn bpd through Q2 and dropping back to differing degrees after that.

Fact Global Energy said it sees global oil demand down by 7.9 mn bpd in 2020. The IEA expects global oil demand to collapse by 9.3 mn bpd over the year and said that 2020 would be “worst year” in history of global oil market. It expects non-OPEC supply will fall permanently by at least 2.3 mn bpd. By mid-April, Rystad Energy said global oil demand was on track to collapse by 9.4 mn bpd in 2020, or 9.4%, due to the lockdown measures—which it revised up to 10.3 mn bpd by the end of the month.

The worst month is expected to be April. Rystad said global fuel consumption is expected to drop almost 28 mn bpd in April to 72.6 mn bpd, and 21 mn bpd in May as a result of Covid-19 lockdowns and restrictions on travel. Goldman Sachs put the April number slightly lower at 26 mn bpd due to “lockdowns affecting over 90% of global GDP.” FACT put the April fall at 24 mn bpd year on year. Earlier in April, Platts said it expected oil demand to shrink by a record 16 mn bpd in April and May, with year-on-year demand falling at least 4.5 mn bpd in 2020—the lowest of the forecasters reviewed.

There are some signs of recovery already, with China slowly ending its lockdown and parts of Europe beginning to loosen restrictions. In fact, China has maintained strong demand for crude throughout the epidemic, although much of this went to storage (see below). There were moderate falls in consumption and refinery throughput in February and March, but that has now reversed. This is not yet the case in the United States and Europe, where demand remains (at end April) sharply down alongside refinery throughput.

Demand is projected to rebound sharply later this year and into 2021, although there are questions over whether it will ever return to the 100 mn bpd level, with key consuming sectors such as aviation and other travel likely to see long term impact from Covid-19. Longer term, the cheap oil could offset any virus-related decline by improving its competitive position relative to alternatives.

2 | DEMAND DECLINE BREAKDOWN—WHAT IS TAKING THE HIT AND WHERE

Rystad said it saw jet fuel being hit the hardest this year with global demand falling 31% year on year, or by at least 2.2 mn bpd. Total demand for road fuels will fall by 9.4%, or by 4.5 mn bpd, from estimated 2019 levels of 47.7 mn bpd.

In the United States, total product demand fell for six consecutive weeks by a total of 37% from early March amid widespread state and local stay-at-home orders (see Figure 2), although there was a rise in the week to 17 April of 306 000 bpd, putting consumption at just 14.10 mn bpd—the lowest on record, according to the EIA. The most recent value is 31% lower than the 2020 average from January through 13 March, or before many of the travel restrictions began.

In Europe, the demand situation appears even worse. The UK’s car use rate sank to about 20% or less in many places through April, with the country’s biggest fuel retailer, supermarket giant Tesco, reporting fuel sales down by 70%. In France, the demand drop is estimated between 70% and 90% for road fuels and 95% for jet fuel, according to FGE. Italy and Spain have been particularly badly hit, with demand slashed by up to 80% for gasoline.

Indian demand for refined products fell 17.8% year on year in March to 4.07 mn bpd, according to provisional data from the Petroleum Planning and Analysis Cell, due to a lockdown lasting 6 weeks, which was implemented 25 March; so the effect in April is likely
to be much more severe. Diesel was down 24.2% year on year in March and gasoline down 16.4%. Jet fuel demand slumped 32.4% year on year as flights were grounded. LPG demand however increased as more turned to home cooking.

The Middle East faces an economic downturn due to low oil prices, as well as the impact of the virus, so while it has yet to be as severe in this region, the drop in consumption of oil products could last longer. After being a driven of global demand growth for many years, demand for oil products there is expected to drop by 2.9% this year, with jet fuel/kerosene consumption down 15% and gasoline 6%, according to Platts mid-April.

China, on the other hand, has already begun to ramp up oil purchases due to the low prices, as well as the impact of the virus, so while it has yet to be as severe in this region, the drop in consumption of oil products could last longer. After being driven of global demand growth for many years, demand for oil products there is expected to drop by 2.9% this year, with jet fuel/kerosene consumption down 15% and gasoline 6%, according to Platts mid-April.

China’s January and February oil imports averaged 10.47 mn bpd, while its Q1 imports averaged some 10.2 mn bpd—a 5% year on year rise. This was despite a fall of 6.9% in GDP for the first quarter, indicating a high level of stock build—driven by the eagerness of Chinese buyers to snap up cheap cargoes, further enhanced by the Saudi OSP discounts.

3 | OPEC-PLUS COMMITMENTS

OPEC’s 13 members, along with their 10 partners in the larger OPEC-plus group, have agreed to reduce their supply by 9.7 mn bpd in May and June. There will be the normal caution over compliance levels, although given the weakness in demand, it may be difficult even to sell the allocated volumes. The cuts will then be eased to 7.7 mn bpd between July and December 2020, and then 5.8 mn bpd between January 2021 and April 2022, according to the agreement.

Russia and Saudi Arabia will use 11 mn bpd as a baseline for the reductions, which they will split evenly—unlike previous OPEC-plus deals, where Saudi Arabia has born the bulk of cuts and Russia very little. For other producers, the baseline will be their output in October 2018 (the basis for previous cuts), which is seen as an advantage for the world’s two biggest exporters, as the 11 mn bpd baseline is up on both Saudi Arabia’s October 2018 production of 10.63 mn bpd, and Russia’s 10.75 mn bpd.

The split of the cuts from the 11 mn bpd baseline includes 2.5 mn bpd for Saudi Arabia and Russia, which will bring their output down to 8.5 mn bpd each in May and June. Both countries will then ramp up output to 8.99 mn bpd for the second half of 2020, and then to 9.5 mn bpd for all of 2021 through to April 2022. It may be more difficult for Russia to control output to this extent for technical and commercial reasons, and a key challenge will be to ensure higher-cost, mature fields do not end up closing permanently.

However, currently (end-April) Saudi output is running well above both target and baseline. According to MEES, Saudi Arabia managed to reach its promised 12 mn bpd production figure (a target following the breakdown of OPEC-plus on 6 March) in early April, and is likely to average its highest ever of 12.3 mn bpd for the month as a whole—so the actual cut for May will have to be close to 4 mn bpd if the kingdom is to meet its deal commitment. Aramco confirmed on 17 April that this was its intent.

On the other hand, production in Russia, Iraq, and Venezuela had already been hit by the price collapse (and competition from discounted Saudi barrels) by mid-April—including falls of 300 000 bpd in Iraq and 235 000 bpd in Venezuela. Russia produced 11.25 mn bpd liquids in March, with 10.60 mn bpd of this being crude, and this is expected to be lower in April—so the actual cut it will need to make in May will probably be <2 mn bpd.
Another sharp cut amounting to almost 1.5 mn bpd has been pledged by the UAE, which also ramped up production heavily after the 6 March OPEC-plus breakdown, to a record 3.42 mn bpd in March, reaching over 4 mn bpd at the beginning of April. This will have to come down to below 2.5 mn bpd. Iraq also has a big cut of about 1.06 mn bpd (around a quarter) to make in May and June, with Kuwait and other OPEC members cutting a similar proportion.

Nigeria has to cut from around 2 to 1.4 mn bpd under the deal but may go lower still as it struggles to sell its oil. Up to 50 mn bbl of unsold Nigerian cargoes remained on the water in mid-April—this was not a deliberate cut by Nigeria, but a simple lack of demand for its crude—partly due to its high jet and gasoline yields and discounts among competing Saudi grades, as well as run cuts in Europe and Asia, and high freight rates on what is a long-haul route to market. So, Nigeria may have fulfilled its entire commitment under the deal without acting and before Saudi Arabia has even started reining in on record export levels.

Altogether, increases in output from Saudi Arabia, UAE, and Kuwait saw OPEC output at a 3-month high of 28.97 mn bpd in March, according to Platts, with compliance among the 10 OPEC countries with quotas collapsing to 13% from 120% in February. This was despite sharp declines among the three members exempt from quotas (Iran, Libya, and Venezuela), where production continues to fall, particularly in Libya due to civil war (see Looking Ahead).

Other countries not in OPEC that are cutting include Kazakhstan and Azerbaijan, where government-imposed cuts are being made to large projects operated by oil majors for the first time. These include the Azeri-Chirag-Guneshli project, which is led by BP alongside partners, Exxon Mobil, Equinor, Inpex, and MOL. Azerbaijan will need to cut its production for 2 months starting in May by 75 to 80 000 bpd, or about 15% of its output.

4 | SUPPLY REDUCTION OUTSIDE OPEC-PLUS

The April deal also includes Norway, Canada, United Kingdom, Mexico, and the United States, although most of the commitments here are likely to come as a result of commercial decisions to shut-in high-cost crude due to low prices or for logistical reasons, rather than government-imposed cuts; and the lower prices go, the more will be shut-in.

Energy Intelligence Group believes up to 7 mn bpd could be shut in for commercial/logistical reasons by June. Citi estimates that such supply curtailments because of logistical bottlenecks and low prices could force 10 mn bpd offline temporarily in April. Goldman Sachs put the figure at 5 mn bpd. The greatest impact will be in the Atlantic Basin, where low prices, high stocks and the longest travel time to customers will likely lead to production curtailments in the United States, Canada, Brazil, and West Africa.

In Mexico’s case, after initially not agreeing to formal OPEC-plus cuts (only offset when President Trump offered to cut on Mexico’s behalf), Mexico said later in April that it would shut down new wells because of low prices. “Now that oil has no value, we can shut down the valves,” said Mexico’s president Obrador. Argentina, which has long forced producers to sell domestically at discounted prices, plans to protect its producers including those in the Vaca Muerta shale patch, with a rise in domestic crude prices to $45/bbl.

The biggest falls outside OPEC-plus are expected to come from the United States and Canada, where WTI prices of $20/bbl puts roughly 5 mn bpd of high cost crude production at risk of being shut in, according to experts. In the United States, strong output growth reversed in March and will continue to fall sharply in April and for the rest of this year and into next. By July it will be declining at a rate of over 200 000 bpd per month, according to the EIA, and recent falls in WTI prices may accelerate this.

The falls will come from output declines as fresh drilling stops and from actual well closures. Rig numbers in the US shale sector have already tumbled (to 438 in the third week of April according to Baker Hughes; down almost 50% on April 2019), indicating a sharp reduction in fresh drilling, which, given the rapid decline rates at US shale wells, will see output falling quickly. A halving of rig numbers is expected to see output down by about 700 000 b/d by December 2020 and around 2 mn bpd by December 2021. The Canadian rig count has also dropped, reaching its lowest level since 2000.

The volume of US well closures is so far unclear, but the EIA expects an overall decline of 2 mn bpd by the end of the year, so that suggests the actual closure of about 1.3 mn bpd in output remaining to be cut after natural decline. More than 10% of US crude production comes from extremely low production stripper wells, which can come offline relatively quickly. Operator cash position, hedging, quality, access to markets, storage options and operating costs are between them likely to determine where the rest of the closures occur. Examples of companies cutting output include Continental Resources, which plans to curtail 30% in April and May, largely from its Bakken production. Similarly, Parsley Energy has begun shutting in about 400 of its less productive wells in the Permian.
In Canada a number of major closures have already been announced in the high cost tar sands in Alberta, while Canada’s Western Canada Select oil, a heavy, acidic crude grade, is under particular pressure as it trades at a discount to benchmarks and has few outlets. Tudor Pickering Holt estimates that as much as 20% or some 340 000 bpd of thermal oil sands production could be shut down due to the oil price slump, and by mid-April the country had already shut-in about 325 000 bpd.

Brazil and Norway were also on the way to cutting their share by mid-April, with Brazil down 200 000 bpd from mature fields onshore and in shallow waters, according to Petrobras. The UK has also made a commitment to cut, although reduced output due to staffing issues around the corona virus and upcoming maintenance may be enough.

Most of the commercial and logistical shut-ins will come from independents and majors, with some non-OPEC-plus Asian NOCs (PTTEP, for example) saying they will continue with existing output and spending plans unchanged. Majors are also exposed to quota-linked reductions among OPEC-plus members, with compulsory cuts being imposed at equity production, including in Iraq, UAE, Oman and Azerbaijan. Longer term, reductions of up to 30% in upstream capex announced by majors will have a significant impact on output from these big producers, putting upward pressure on prices and expanding OPEC market share in future years.

5 STORAGE CONTINUES TO BALLOON

The collapse in global demand and surge in April supply is rapidly filling up the world’s spare storage capacity—encouraged by a steepening market contango, where future oil prices are higher than prompt.

The IEA’s Fatih Birol said the filling of strategic stocks by countries would provide some relief to the oil market but would not be able to absorb all the supply surplus. “At least four countries, namely China, India, South Korea and the United States, have either offered their storage capacity to industry to store their barrels or are increasing their strategic stocks to take advantage of lower prices,” said Mr Birol in mid-April.

“This will provide greater headroom for the surplus supply peak in the coming weeks,” estimating these efforts could take out 200 mn bbl. “Assuming they happen in the next three months this could represent as much as 2 mn bpd of supply withdrawn from the market,” he said.

The US SPR looks likely to be filled by private companies leasing storage, rather than government purchases, with Congress not making public funds available. By mid-April, at least nine US oil producers were talking with the government over storing 23 mn bbl in the SPR, according to the US DOE. Most of the deliveries will be received at the four main SPR storage sites on the Gulf Coast in May and June. The SPR would still have about 55 mn bls of capacity.

Commercial US reserves are also on the rise. As of 20 April, they rose to 503.6 mn bbl, or about 6% above the 5-year average for this time of year, with further sharp rises to tank-top anticipated for both crude and products over coming months.

China and India are also filling their strategic reserves with cheap oil. India only has about 12 to 13 mn bls of spare capacity out of a total SPR of 39 mn bbl. China has a great deal more, with strategic reserves expected to reach 1.15 billion barrels this year, as the second phase of its strategic reserve development is completed. Chinese inventory levels have been rising at 2 mn bpd since the beginning of the year.

Floating storage is also a viable option. By mid-April, estimates suggested over 200 mn bbl of oil was already held in floating storage, including on 50 to 60 very large crude carriers (VLCCs) and smaller tankers typically found in the US Gulf of Mexico and Singapore. In theory, the global crude oil tanker fleet can carry up to 3 bn bbl, but realistically, only 300 to 500 mn bbl are available, according to EIG.

Some vessels have been booked to store crude for up to 3 years, potentially the longest ever duration for floating storage. Storage costs have surged, supported by the steepening market contango. This has put upward pressure on freight rates generally, making it more expensive to move oil around the world, which is adding to market access problems for crudes with long haul routes to market, such as United States flows to Asian refiners.

Russia’s storage facilities are limited, and are not designed for long-term storage. Russia’s state pipeline and storage operator, Transneft, is thought to have 422 000 bpd of capacity both for crude and products, including in the pipeline system, trans-shipment points and storage, according to Platts. Russia’s four key export outlets on the Baltic, Black Sea, and Sea of Okhotsk can store up to 55 000 bpd.

6 REFINERS CUT AS SALES TUMBLE

Refiners are responding to lower demand with run cuts. By 10 April, global refinery runs were down by about 14 mn bpd according to Platts, with European outages at record highs and US refiners considering further cuts—
although some cuts in Asia were already beginning to be reversed by end-April. Platts expects overall second quarter runs to be 10 mn bpd lower in 2020 than in 2019.

In the United States alone, run cuts peaked at 4.77 mn bpd of crude distillation capacity in mid-April, and are expected to hit 5 mn bpd by the end of the month; and continue to decline beyond that. BP’s US refineries were reported to be running at between 10% and 30% below normal in mid-April.

Asian refiners cut runs by 2.7 mn bpd in the first quarter of 2020 and are expected to cut throughput by at least 4 mn bpd in the second quarter, although they are likely to recover by June. China’s state oil companies began raising refinery utilization rates mid-April due to recovering demand as industrial production and transportation resume. Sinopec raised its run rates to 72% in March from a historical low of 64% in February and will further increase throughput in April, according to Platts. PetroChina’s refineries, most of which are in northern China and inland, have cut their average throughput plan from 78% in January to 66% in February to 64% in March.

Refiners elsewhere in Asia, including Japan, are considering more cuts. Japan is already facing excess crude supply of about 16 mn bbls in June, as storage fills up and refinery runs are cut 14% to 20% (500 000 bpd and over) to balance reduced demand, leading refiners to delay term crude deliveries. Indian refiners have also declared force majeure on some crude imports due to the lockdown there, with state-Indian Oil Corp cutting throughput at most of its refineries by 25% to 30%. Lockdowns in Malaysia, Thailand, and Pakistan have also led to sharp run cuts there.

South Korea has also cut, but has seen less impact on demand, although stocks are filling. Some of the cuts here will come from delayed commissioning and expanded maintenance. For example, SK Energy has delayed commercial production from its new 40 000 bpd vacuum residue desulfurization unit. GS Caltex has brought forward regular maintenance. European refining outages were around 2 mn bpd mid-month, with as much as 50% of downtime (about 600 000 bpd) linked to tanktop storage, despite strong margins as crude slumped.

The steep Saudi crude OSP discounts to Asian refiners mean they are likely to be protected to some extent compared to other regions, as well as ensuring Saudi grades retain market share among Asian refiners, at the expense of competing grades. Saudi Arabia has also left May 2020 OSPs to US refiners at relatively low levels, resulting in at least 20 Saudi VLCCs heading to the Gulf coast, putting further pressure on US producers. For Europe and the Mediterranean, April’s OSP cuts have been maintained, continuing the discounts against Russian Urals’ pricing, and making it difficult for Russia to compete for sales.

However the eventual supply cuts pan out, the industry is unlikely to ever be the same again, and Covid-19 may have further, as yet unforeseen implications for demand—although there is the possibility that supply adjustment will enable a fresh balance in the market by later in the year, and some price recovery from there on.

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