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Middle East Oil Pricing Systems in Flux

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A QUARTERLY JOURNAL FOR DEBATING ENERGY ISSUES AND POLICIES

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INTRODUCTION

This issue of the *Oxford Energy Forum* is devoted to analysing the recent shifts in oil trade flows and the major developments in pricing benchmarks in Middle East crude and products markets.

The region is experiencing a series of dramatic structural changes that are transforming crude and products flows, as well as leading to an increased focus on the price benchmarks used to underpin activity in the region.

The Gulf countries traditionally exported crude oil, while also importing much of the refined products that they required. The construction of several major refineries around the Gulf has changed this model, turning the region into an exporter of refined products. This new focus on refined products in part reflects the increased domestic demand within the region, as local populations grow and as energy-intensive industries develop.

Meanwhile, the impact of the COVID-19 pandemic on energy demand has weighed particularly heavily on the Gulf as one of the world's major suppliers of hydrocarbons, exposing some of the cracks in existing oil benchmarks, oil price assessment processes, and the relationship between the different benchmarks.

The pressures on governments and the region's national oil companies to ensure they are maximizing their revenues from their crude oil and products exports is leading to a new focus on the trading activity and pricing mechanisms that underpin the Gulf's exports, with recent months seeing some major changes—such as ADNOC removing destination restrictions on its crude grades and moving from a retroactive to a forward-pricing model. With the launch of the ICE Futures Abu Dhabi (IFAD), the region now has two exchanges (IFAD and the Dubai Mercantile Exchange (DME)) and two crude oil futures contracts, while the incumbent benchmark (Platts Dubai) continues to attract liquidity and remains dominant in pricing crude going out of the region. And the COVID-19 demand shock gave Shanghai International Energy Exchange (INE) oil futures contracts a boost, as excess supply of oil naturally gravitated to China, the biggest oil importing country in the world, increasing spot activity in delivered barrels into the country. As Middle East–Asia crude and products trade flows become more important over time, and as the role of Asia as the most important demand centre consolidates further, the role of Asian players in pricing crude and products will only increase and the desire to turn regional benchmarks into global ones will only intensify.

But as trade flows between the Middle East and Asia consolidate, the nature of the relationship will continue to evolve, with consequences on the pricing of crude and products. While Asia will remain the main importer of Middle East crude, refiners in the Middle East and Asia will increasingly compete on products markets and petrochemicals, as both have very ambitious plans to expand refining capacity and integrate refining assets with petrochemicals.

In the first article, *Adi Imsirovic* sets the scene for the *Oxford Energy Forum*, noting that there has probably never been such an exciting time for crude oil benchmarks. Due to changing flows, and accelerated by the demand shock resulting from the pandemic, the established oil benchmarks are changing, and new ones are emerging.

Imsirovic reviews the contenders for the primary Gulf crude oil benchmarks—Platts Dubai, DME Oman, INE Medium Sour, IFAD Murban—before ultimately concluding that the most important benchmark for the region remains Brent, which itself is in need of reform.

In the second article, *Reid l'Anson and Kevin Wright* note that the Middle East has proved to be one of the major beneficiaries from sharply growing Asian demand for both crude oil and refined products. Asia has overtaken the US as a key demand centre for Gulf oil, with China and India emerging over the past decade as the region's most important trading partners.

But the authors warn that the US has turned from a consumer of Gulf crude to a competitor, with US crude oil exports now competing to a certain extent with Middle East producers to supply East Asia.

After these two overview articles, the *Forum* turns its attention to the individual crude oil benchmarks that are competing to dominate the 'East of Suez'.

The oldest and best-established regional benchmark remains Platts Dubai, and *Dave Ernsberger* notes that Dubai is experiencing a surge of fresh vitality as it turns 41.

Abu Dhabi's decision to remove destination restrictions means that there has never been more spot crude oil available for physical delivery into the Dubai benchmark, while volumes of Dubai derivatives trade have hit fresh record levels throughout the past year.



Paul Young suggests that Oman proved its worth as a benchmark during 2020, when the benchmark held up well during the pandemic, while other regional and global benchmarks experienced challenges.

Young also argues that Oman, as a medium sour crude oil, is the most representative grade as its quality best reflects the majority of regional production.

The latest benchmark contender—Murban crude oil as listed on ICE Futures Abu Dhabi (IFAD)—has a strong chance of becoming a major reference point for the region and beyond, argues *Mike Wittner*.

Murban has high, reliable, and stable volumes of both crude production and exports, and is expected to increase its production and its ability to export more. Murban's light sour characteristics are different to the majority of Gulf production, Wittner notes, but it matches more closely UK Forties (part of the Brent assessment) and US WTI. Murban also has a diverse pool of buyers and sellers and good storage availability.

Jorge Montepeque is less convinced that the Middle East can support a major benchmark, arguing instead that the oil world revolves around CME WTI and ICE Brent and that any other pricing points will, at best, be mere regional spreads to the two main global contracts.

Montepeque reviews the first few weeks of IFAD Murban and finds reasons for concern in the product's design, its performance, and its liquidity, although acknowledging that the contract is still in its early days and may evolve further. Montepeque argues that IFAD, like DME, should moderate its expectations, given the challenging nature of establishing a new benchmark.

Evolution in the face of market challenges has been a hallmark of Iraq's Basrah crude oil exports, suggests *Ahmed Mehdi*. In January 2021, Iraq launched a new grade, Basrah Medium.

This was the second time that Iraq had split its Basrah crude stream, the first being in 2015 when it split its key grade into Basrah Light and Basrah Heavy. The splits reflect the evolving nature of Iraqi production, and Iraq's need for greater consistency in its export grades.

The changes mean that the grades now better reflect the country's upstream realities, Mehdi notes, but will require Iraq to pay close attention to the pricing of its various grades in order to ensure that official selling prices reflect market realities.

The final article on the East of Suez crude oil markets covers China's launch of a medium sour crude oil futures contract as listed on Shanghai's International Energy Exchange (INE). The futures contract has attracted strong interest from financial and speculative traders, writes *Tom Reed*, but has so far failed to gain traction either as a benchmark or as a physical procurement mechanism.

The impact of the pandemic led INE to add additional storage to the contract, to its benefit, and Reed notes that physical delivery from the INE futures increased in 2020, even though the delivery process remains complex and potentially risky for all but the largest players. The addition of Murban to the basket of INE deliverable crudes from June is another positive new development, although it remains unclear whether INE will take off as a significant physical benchmark.

The focus of the *Forum* then turns to infrastructure and to the other energy markets in the region: both refined products and condensates.

The port of Fujairah has emerged as the key hub in the region for oil trading, storage, bunkering, and price benchmarking. In their article, *Captain Salem Al Afkham Al Hamoudi* traces the development of Fujairah, which has changed from a sleepy fishing harbour to become a rival to Rotterdam and Singapore.

The next evolution of Fujairah is likely to be increased crude oil storage and trading, Al Hamoudi suggests, on the basis of strong support from ADNOC commitment and the launch of IFAD Murban. Fujairah is also striving to further diversify its portfolio by developing LPG and LNG infrastructure, as well as playing a key role in the renewable fuels landscape.

The development of Fujairah as a trading hub, and the increasing importance of the Middle East as a producer as well as a consumer of refined products, means it is time to examine the netback mechanism that underpins Gulf price benchmarks, argue *Ahmed Mehdi* and *Iman Nasser*.



Calculated as freight netbacks that derive their value from Singapore product prices, Means of Platts Arab Gulf (MOPAG) price assessments remain at the heart of the Middle East product pricing complex, but pressure has come from Gulf refiners in recent years to switch to flat-price assessments in order to capture changing regional dynamics.

Outright assessments based on Fujairah have tended to be higher than netback prices, Mehdi and Nasser note, but the industry continues to use the traditional netback model to price their products, in part because of the liquidity and familiarity of the incumbent, as well as concerns around concentration risk among the participants in the Fujairah market.

The jet fuel market is one of the most vibrant and rapidly evolving energy markets in the region, despite the enormous impact that the pandemic has had on demand, notes *Julien Mathonnière*.

Jet fuel demand growth prior to the pandemic spurred major refinery upgrades, which expanded the region's jet fuel surplus even as local usage continued to grow. The most significant excess capacity globally is forecast for the Middle East, writes Mathonnière, with recovery in demand likely to be a slow process and dependent on the resumption of the long-haul flights in which the Middle East airlines specialize.

Condensate remains a challenging commodity to evaluate, given that some traders view it as a refinery feed that competes with crude, while others see it more as a petrochemical feedstock that competes with naphtha.

Thomas Olney says it was no coincidence that the modern condensate market developed in the 1990s, based on two factors: the development of the South Pars gas condensate field (first production, 1989) and the adjoining Qatari North Field (first production, 1991), combined with the growth of Asia's petrochemical industry from the 1990s onwards.

Olney notes that much condensate is priced versus crude oil benchmarks, such as Brent, WTI, or Dubai. Olney wonders whether the emergence of IFAD Murban may provide the industry with an alternative benchmark for condensate, although he suggests that the greater liquidity of Brent and Dubai may make any switch to Murban a challenge.

Andy Laven agrees that condensate is a complex product that 'flies under the radar'. Condensate production in the Middle East is increasingly being used within the region, reducing exports, while those that do take place are generally into Asia, where Gulf exports face competition from growing US production.

In the Middle East, there is an increasing alignment between production of condensates and regional demand, which should be supportive of the need for a Middle East benchmark, Laven argues. However, the Gross Product Worth (GPW) of Qatar condensate will be very different from any likely Middle East crude-based benchmark; for blending into gasoline a gasoline-based price would be ideal, but for use in a splitter to produce distillates a price based on gasoil would be better, he points out. Unfortunately, the condensate market is quite fickle and slow to change, and the momentum which supports WTI and Brent pricing is difficult to overcome.

The final article in the *Forum* addresses the shipping market that is so crucial to a region that is so heavily dependent on import and export activity.

The last decade saw the emergence of the shale industry transform the energy landscape in the US, altering global flows of crude and boosting the crude tanker market. This coming decade will bring the construction of new refineries in the Middle East and Asia, feeding demand growth for oil products East of Suez and potentially boosting demand for refined products tankers.

Between 2009 and 2019, the volume carried by products tankers grew by 2.3 per cent per annum; this is higher than the growth rate of crude production (1.2 per cent), refinery throughput (1.3 per cent), or end-user demand (1.6 per cent), notes *Tony Foster*. The pandemic has clearly impacted on global demand, and in mid-2021 the market for both crude and products tankers remains depressed and dependent on a rebound in oil demand.

Over the medium term, the rising tide of demand in Asia will support growing volumes of both crude and oil products trade, but only the latter is likely to see an additional boost from increasing average haul. As a result, products tankers could begin to outperform crude tankers, Foster suggests.



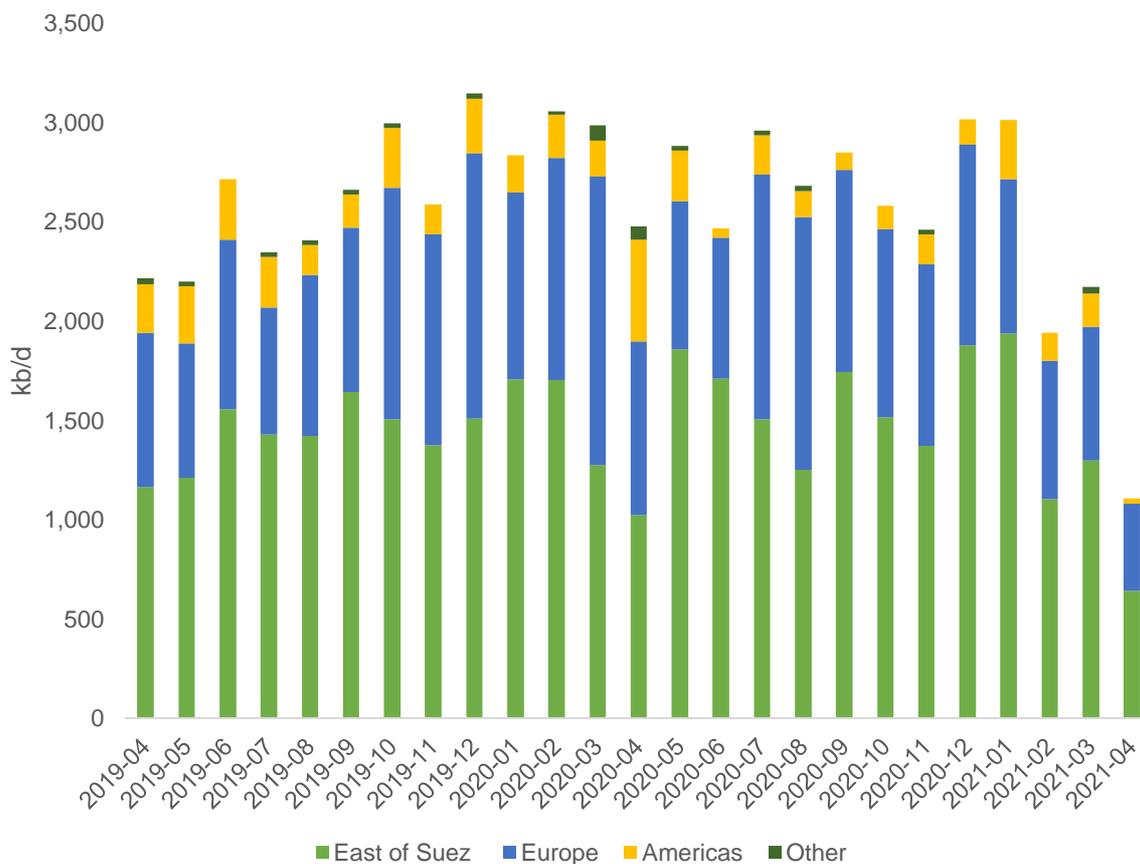
THE GULF/ASIA BENCHMARKS: SETTING THE SCENE

Adi Imsirovic

There has probably never been such an exciting time for crude oil benchmarks. Due to changing flows, and accelerated by the demand shock resulting from the COVID-19 pandemic, the established oil benchmarks are changing, and new ones are emerging.

In the last decade or so, two key changes have impacted global oil flows. Firstly, the centre of gravity of the oil demand has been firmly established 'East of Suez', with China and India dominating the world's incremental crude imports. Secondly, as can be seen in the chart below, the advent of shale oil and the lifting of the US export ban at the end of 2015 has seen freely traded United States (US) produced crude oil becoming an important marginal supply in virtually all corners of the world, impacting the key demand centres in Asia and Europe.

US crude oil exports by regions (2019–2021)



Source: Kpler.

What is more, the COVID-19 pandemic, and the demand shock it created, exposed some weaknesses in the global oil pricing system ([Fattouh and Imsirovic, 2020](#)) and showed us what the markets might look like after the oil demand has peaked.

While the two key global crudes—Brent and WTI—are not strictly Middle Eastern and Asian benchmarks, their evolution is closely linked to these markets, and will be addressed first.

With the growing importance of US oil exports to Asia and the rest of the world, the focus of the WTI price has gradually been shifting to the US Gulf Coast, the most important pricing point for end users shipping their own oil. As a result, the two biggest PRAs and the two major oil exchanges developed price assessments there: Argus Media (Argus) and CME Group focused on the WTI Houston (Permian), while S&P Global Platts (Platts) and the Intercontinental Exchange (ICE) focused on WTI delivered in the Magellan East Houston (MEH) terminal. Also, in 2020, Platts and Argus both started publishing the American Gulf Coast



Select (AGS) assessment of waterborne light sweet crude oil loading 15–45 days forward from the US Gulf Coast including Houston, Corpus Christi, Beaumont, Nederland, Texas City, and Port Arthur with, in Platts' words, the 'most competitive location on an Aframax cargo-size basis setting the price assessment.'

These prices have generally started as differentials to the WTI benchmark in Cushing, but their introduction has facilitated price discovery similar to that of the other competing seaborne grades of oil popular with the Asian buyers and globally.

Most Asia Pacific 'regional sweet' crude oils produced in Australia, Malaysia, Vietnam, Indonesia, and other countries are priced on the basis of Dated Brent. What is more, large volume of Dated Brent-related oil, such as West African grades, are imported into Asia. The Chinese independent refiners generally price their oil purchases using Brent futures as the most liquid instrument for managing their refining margins. Finally, given Brent's major influence on the price level of Dubai, the benchmark is essentially a key barometer of prices in the Middle East and Asia.

Falling production of deliverable grades into the Brent basket, and the establishment of the US crude exports as the base slate for many European refiners, have shaken the most important global benchmark. In 2020, US crude imports into Europe exceeded the production of North Sea oil. It naturally follows that the ample supply of a stable quality of WTI Midland should be included into the Brent benchmark.

This inclusion would result in a more seamless arbitrage between the two markets, benefiting both key global benchmarks. However, engineering such an inclusion is far from easy. Due to the lack of published loading programmes for WTI Midland and the complexity of the Brent market (based on forward, Dated, and futures contracts, as well as a plethora of derivative instruments), both Dated and forward or cash Brent need to be assessed on the same delivery basis. Any difference between the two would cause poor convergence during the expiry of the contract and a decoupling of the values of key derivative contracts—such as contracts for difference (CFDs), dated-to-front line swaps (DFLs), and exchange for physicals (EFPs).

One viable option was to assess both cash and Dated Brent based on a wide delivery location such as the Amsterdam–Rotterdam–Antwerp (ARA) area. However, the oil industry vocally rejected this, with some justification (see [Imsirovic, 2021](#)), as it would be too disruptive for the existing futures and derivatives contracts. Having recognized the extent of the effort required and the potential consequences of these changes for the whole industry, Platts have started a series of discussions with industry participants. However, the volume of oil in the Brent basket is dwindling fast, and WTI Midland is the obvious choice from both a volume and quality point of view. The inclusion of the grade into the forward Brent contract, while retaining the existing or similar nomination procedures, remains a challenge that needs to be resolved soon. The way in which the inclusion may be resolved will have an impact on the pricing of oil in the Middle East, Asia, and globally.

China is the world largest oil importer and is expected to become the world's largest oil consumer before 2040. As a part of the country's economic ascent and a shift of the market gravity towards Asia, the Chinese Communist party leadership has made a conscious decision to 'compete for oil pricing power'. Part of this effort was the establishment of an oil futures contract, seen as way of strengthening China's pricing power in the international oil markets.

Established in 2018, the Shanghai International Energy Exchange (INE) and its crude oil contract have been a success, becoming an important source of price discovery for delivered oil crudes to China. In the process, it has become the third crude oil futures exchange contract in the world. Coupled with a number of other delivered price assessments for China and India by the price assessment agencies (PRAs), the INE oil contract has greatly contributed to increasing transparency in these markets. However, the yuan-based contract has remained being traded primarily by retail and financial participants, with limited access to the international oil markets. The lack of participation by independent refiners, together with some infrastructure issues and, most importantly, the slow pace of the market liberalization process, make the contract an unlikely regional, let alone global, benchmark.

However, the contract has the potential to grow substantially. For example, if the INE price settlements were adopted as a part of the domestic, government guaranteed, refinery margin floor, independent refiners, as well as the Chinese majors, would be forced to use it as a hedging tool for at least a portion of their crude oil purchases. The exchange has shown its ability to adapt quickly (see [Imsirovic and Meidan, 2020](#)) and the oil contract may continue to evolve over the coming years into an important trading instrument.

The Middle East oil producers have responded to the shift towards greater transparency by moving away from opaque, retroactive pricing, towards a more predictable 'forward' pricing. Oman has been a pioneer in delegating the official selling



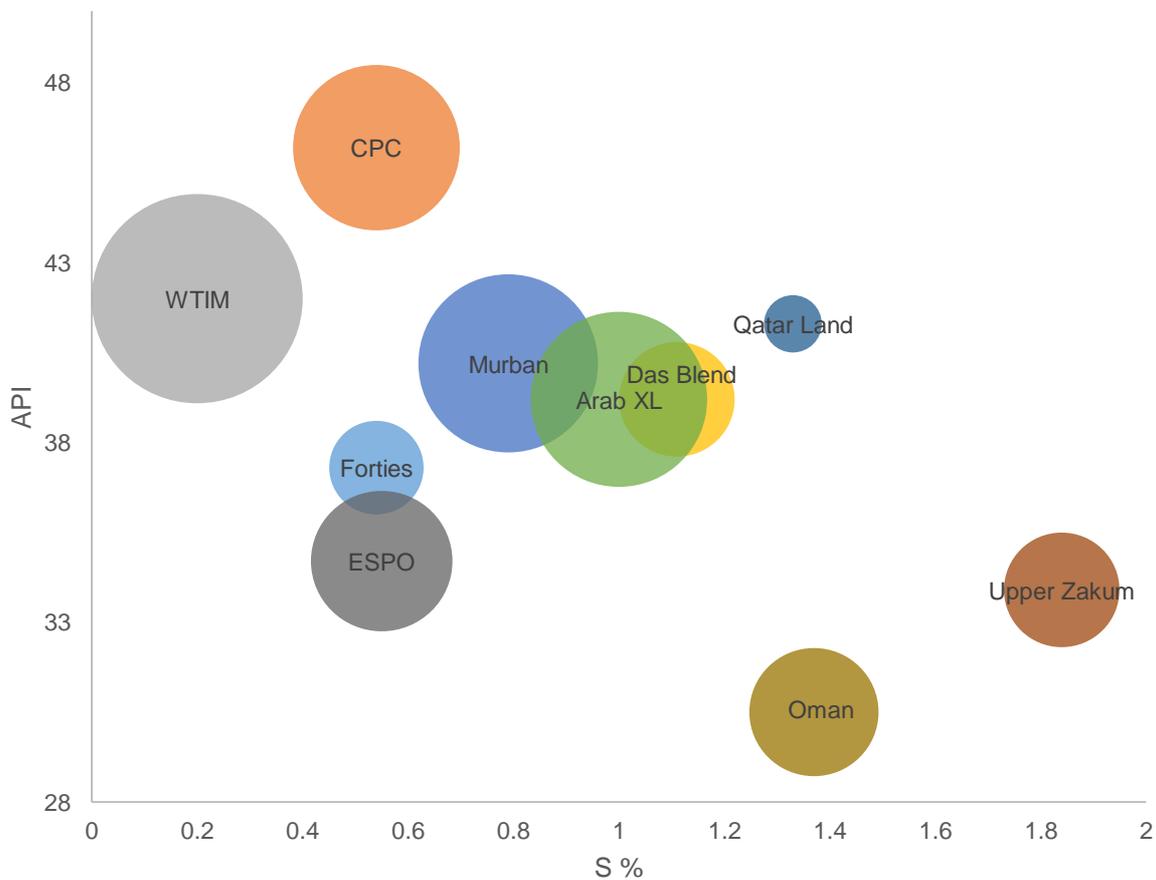
prices (OSPs) to the market, following the launch of the Dubai Mercantile Exchange (DME) in 2007. Now both Qatar and the UAE have aligned their pricing with the rest of the Middle East market, making it easier for refiners throughout Asia to choose the most profitable grades of oil for their systems.

For well over a decade, the DME exchange has functioned reasonably well as a vehicle for facilitating the physical delivery of Oman crude and setting its official selling price. It has been far less successful as a financial instrument for hedging and speculation. The DME Oman continues to suffer from poor liquidity outside the settlement ‘window’, and towards the expiry of the contract. These problems could be fixed by introducing an alternative delivery mechanism and other measures (see [Imsirovic, 2018](#)), but the contract is an example of the old adage that liquidity trumps basis risk—traders are more likely to use a more liquid contract in spite of higher basis risk associated with it. Still, DME Oman will remain an important instrument in price discovery in the Middle East.

By launching the IFAD Murban futures contract with the ICE exchange, the UAE has joined Oman in leaving the OSPs to be determined by the market. The contract came into life with a big fanfare and predictions that ‘the attention of global oil traders and speculators is likely to turn rapidly to the Murban contract as a substitute for Brent and possibly WTI’. ([Philip Verleger, World Energy Opinion, Energy Intelligence, 17 March 2021](#)) These views were grossly exaggerated.

The contract does have a few very attractive features (see [Mehdi et. al., 2019](#)). Murban is one of the largest crude streams in the Middle East, and ADNOC’s plans to significantly raise the production capacity in the next decade make it a highly fungible, long-term grade of oil for setting prices. Delivered crude to Asia has been getting lighter and sweeter, and Murban quality is not unlike the other competing grades in the region—such as North Sea Forties, Russian ESPO, and US WTI. In terms of gravity and sulphur content, Murban quality (see the chart below) sits comfortably in the middle of the existing grades of oil influencing the East of Suez markets.

Crude oil qualities (API, sulphur (S) %, volume)



Source: various crude oil assays.



Murban is widely accepted by refineries throughout Asia and the loading port, Fujairah, has excellent and expanding storage and loading facilities outside the Strait of Hormuz. A successful Murban contract would facilitate hedging a portion of the LNG price risk based on the Japanese Customs-cleared Crude benchmark (JCC), normally an unhedgeable pricing formula.

However, the history of oil markets teaches us that few crude oil contracts have been able to achieve the status of regional, let alone global, benchmarks. The essential quality of a good benchmark is not just liquidity, but a lack of government intervention in the market (liberalized market policies), and the absence of undue influence from any large player or group of players. The new IFAD Murban contract still does not satisfy these conditions. Abu Dhabi is an OPEC member, subject to joint output decisions which may well impact the supply of oil in the contract. ADNOC plays a major role on the exchange as an owner and market maker, and also as an exporter of crude. The huge ADNOC Ruwais refinery is capable of running a good share of the Murban production. While they have tried to run alternative grades, it is hard for imported grades to compete, given the freight advantage of Murban.

It is quite possible to mitigate some of these issues, but like the Shanghai INE contract, a large number of varied international players are unlikely to be active participants until it is absolutely clear that the contract offers a level playing field for all. It is way too early to judge IFAD Murban. Before getting overambitious about its global role, the exchange will first have to prove that its physical delivery can work seamlessly, a lesson that DME learned the hard way.

Dubai, the key benchmark East of Suez, continues to perform reasonably well, partly because of its strong link to the liquid Brent complex. During the demand shock of 2020, it had some issues, linked to the value of Murban (see [Fattouh and Imsirovic, 2020](#)), a deliverable grade in the Dubai basket. However, the problem can be fixed and was most likely a one-off event, caused by the massive collapse in the demand for mobility during the pandemic. With ample liquidity during the Singapore window, Dubai is likely to remain the key benchmark for Asia. For most regional refiners, it is a common denominator for comparing netback values of different grades of crude for procurement purposes. For this reason, a move from Dubai to an alternative benchmark such as Oman or Murban would require a tectonic shift in the marketplace.

Such a shift could come from a failure to increase the volume of deliverable oil in the Brent benchmark, which sets the absolute price for Dubai. For this reason, fixing the Brent benchmark is of utmost importance for oil pricing East of Suez and globally.

THE SHIFT IN CRUDE AND PRODUCT FLOWS

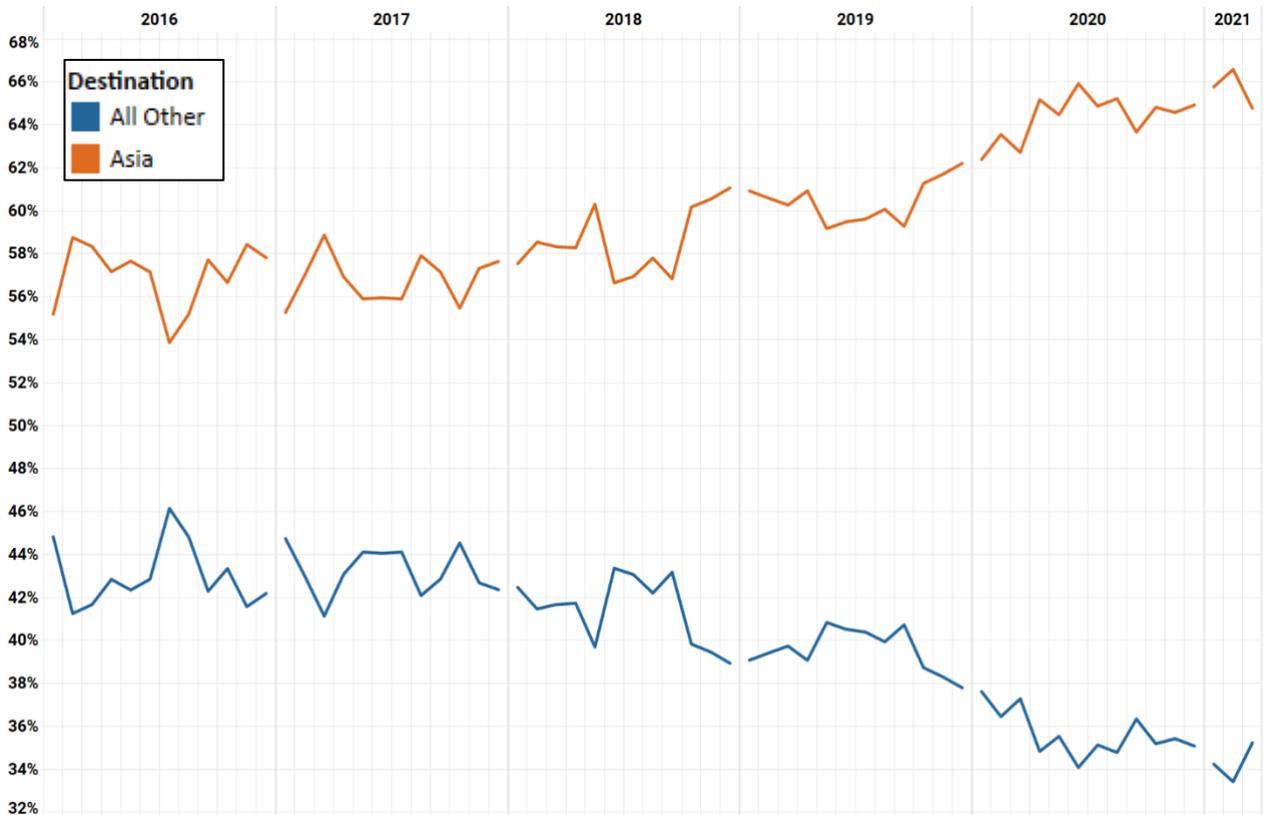
Reid I’Anson and Kevin Wright

It is undeniable that Asian markets east of the Arabian Sea have been the linchpin supporting continued oil demand over the past decade. China alone has garnered much attention for procuring an ever-growing quantity of total seaborne oil, which has primarily satisfied growing local demand, but which has also subsequently helped to drive more clean product exports leaving the country. This is a notable change in a market long dominated by crude oil flows into the US, specifically to the US Gulf Coast with its highly complex refinery infrastructure. The rise of domestic US shale oil, even in a post-pandemic world, is set to continue to play a key role in limiting US dependence on foreign oil, while exports of US surpluses will simultaneously compete with Middle Eastern producers into East Asia. Lastly, there are the issues of European refining and the knock-on effects of an ageing system hamstrung by capacity constraints and logistical challenges. The Old Continent has had an onerous time of ensuring profitable returns on largely medium-complexity refineries, pushing oil producers to focus on East of Suez markets.

On a market share basis through 2020, Asian purchasers (including the subcontinents of the Middle East, South Central Asia, and South East Asia) took more seaborne oil than at any point in the past. Imports finished the year at 23.9 mb/d, accounting for 63 per cent of offtakes, up seven percentage points from the levels of five years earlier (see chart below). Unsurprisingly, the bulk of this gain came from China, with a market share finishing 2020 at 27 per cent, nine percentage points higher than 2016. Of course, some of this Chinese demand was skewed to the upside in 2020 following record crude purchases in the April/May period amidst record low spot prices. Much of this purchased volume went into onshore storage, with inventories increasing by 161 million barrels by September 2020, although these stocks have since drawn slightly, down 25 million barrels. Nonetheless, even when examining China in 2019, the country accounted for 23 per cent of all seaborne arrivals, up five percentage points from 2016, so the upward trend narrative remained valid, even before the outbreak of COVID-19.



Global seaborne exports by region in market share terms



Source: Kpler.

'Asia' includes the Middle East, South Central Asia, South East Asia, and East Asia

The increase in Chinese demand comes alongside a historic expansion in refinery throughput capacity. In 2020 alone, total crude runs, as reported by the Chinese National Bureau of Statistics (NBS), finished at 13.8 mb/d, a gain of 25 per cent over a five-year period. All this new refinery capacity needs crude sourced from abroad—this issue being magnified by the fact that domestic oil production has declined significantly since 2015, off by some 400 kb/d. The increase in refinery capacity has gone far beyond the needs of the Chinese market, driving a robust clean products export market. On a market share basis, Chinese refiners exported 5.9 per cent of all seaborne clean barrels in 2020, a one percentage point increase from 2016 levels.

India, the other large oil importer in Asia, has underperformed compared to expectations in recent years, at least when it comes to oil demand. As a percentage of global imports, Indian seaborne oil imports have held relatively constant, within a range between 10.5 per cent and 11 per cent, since 2016. Indian oil imports in 2020 finished at just 3.9 mb/d, 270 kb/d below the total for 2016. This was primarily the result of COVID-19 demand destruction, but even in 2019, oil imports finished at just 4.35 mb/d, down 90 kb/d year-on-year, marking the first such decline in at least the previous half decade. The situation has since improved into 2021, albeit imports remain below 2020 levels as a fresh wave of COVID-19 infections sweeps through the country. India is unlikely to manage a return to oil demand growth until late-2021 at the earliest.

South East Asia (specifically Vietnam and Thailand) has also helped to buoy crude imports into the Asian region. Both countries managed to grow market share for oil imports by a combined one percentage point over the past five-year period, a relatively limited gain when considering places like China, but still notable considering that these countries are vastly smaller in terms of net product consumption. On an absolute basis, oil imports into Vietnam and Thailand finished 2020 at 1.05 mb/d, marking a gain of 330 kb/d against 2016.

US oil producers claim market share from Middle Eastern producers

US oil producers have benefited from an OPEC+ organizational stance that has emphasized production restraint in a bid to support prices over the past several years. US producers have largely filled the gap. Even in 2020, US seaborne oil exports managed a market share position of 7.4 per cent, an all-time high and well above near nil levels in 2016 when the US first lifted



a longstanding export ban (December 2015). In total, this translated to absolute export volumes near 2.94 mb/d through 2020, up nearly 2.6 mb/d against volumes from a half decade earlier. Such elevated export levels, despite the persistence of COVID-19, were driven, in part, by Chinese demand. After holding at near zero between October 2019 and March 2020, US shipments towards China exploded, topping out at a record 1.3 mb/d in May and averaging nearly 515 kb/d above the previous 13-month period, pushing US market share in China to levels above 4 per cent.

A resumption in the US to China oil trade is notable and marks a reversal from previous Chinese governmental policy. This was the result of two factors.

- Given OPEC+ production cuts, US oil was a viable alternative. Departures of light sweet Midland (148 kb/d) and WTI (80 kb/d) grades dominated the trade of US oil into China, albeit Mars (78 kb/d), a heavier, offshore alternative, was also popular.
- The Chinese wanted the appearance, at least in part, of complying with the Phase I trade deal originally agreed between the two countries in January 2020. This agreement saw the Chinese government spending a total of \$18.5 billion on additional energy commodities against a 2017 baseline. Unfortunately, while US oil exports towards China hit a new all-time high during 2020, this did little to fulfil actual obligations, given record low oil prices.

Inversely, OPEC+ producers have lost significant oil market share, at least on the seaborne side of the trade. In 2020, OPEC+ shipped 26.37 mb/d, which equated to a market share of 67 per cent, an eight percentage point decline against 2016 levels. This is a somewhat unfair comparison given the prevalence of COVID-19, but even before the pandemic, OPEC+ had undergone a big degradation in the overall trade of seaborne crude. In 2019 alone, market share finished down four percentage points against 2016. The five-year decline in share has had varying effects based on destination. Exports towards China finished up 1.7 mb/d, but this was not enough to prevent a decline of more than eight percentage points in the share of total barrels entering China. It is worth bearing in mind that China took on record amounts of crude in 2020, and thus non-OPEC producers were the biggest beneficiaries. Interestingly, US oil imports, which are still above 2 mb/d, are down by half against 2016 levels, with the bulk of this loss being a result of OPEC+ barrels.

European refiners struggle amid a general flattening in European clean product demand

Seaborne oil imports to Europe were predictably anaemic in 2020, finishing the year at just 10.3 mb/d, a decline of one percentage point against levels from five years earlier. In other words, European oil demand is slowly but surely giving way to demand in Asia. Even in 2019, before COVID-19 had taken hold, seaborne oil departures towards Europe were less than impressive, finishing at 11.84 mb/d, up just 500 kb/d against 2016. OPEC+ has borne the brunt of European demand weakness, with exports towards the region down 1.79 mb/d over the five-year period ending in 2020. The relative lack of growth in the European market is helping to drive oil towards Asia.

The steady increase in oil volumes sold into East of Suez markets is a clear result of strong multi-year growth, especially within East Asia, and of a US market that continues to flirt with net export status, which is a significant change from its position as the largest oil importer just half a decade earlier.

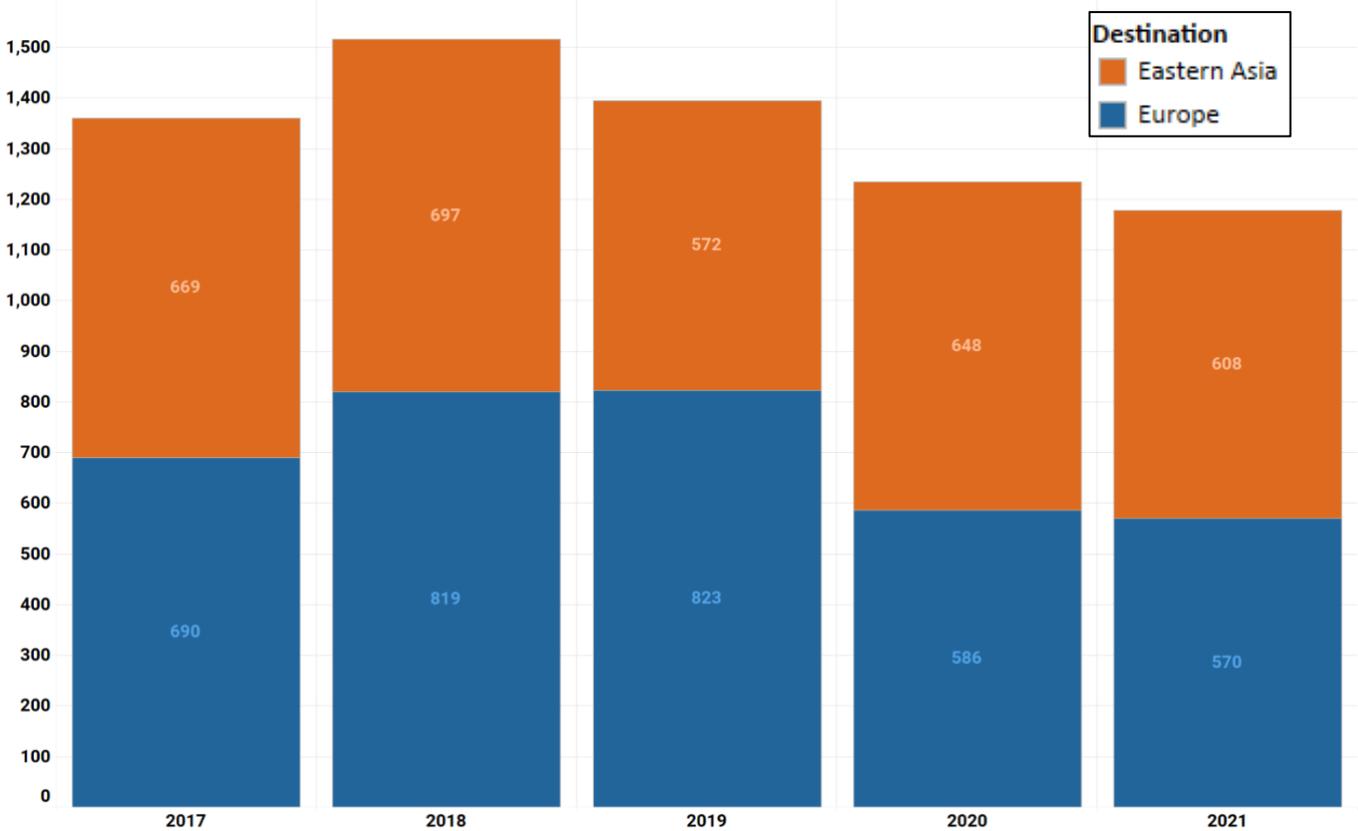
The increase in refining capacity within East Asia, namely China, has helped to shift Middle Eastern clean products exports towards West of Suez markets

In the years leading up to the COVID-19 pandemic, East Asia was the clear growth region for seaborne exports of clean petroleum products. During 2019, exports finished at 2.95 mb/d, up 620 kb/d against levels from just two months earlier. In total over the year, East Asian exporters captured some 16.6 per cent of the seaborne market, higher than any other region and up by three percentage points from 2017 levels. This largely came at the expense of North West Europe, which realized a near one percentage point decline in share over the same period. The Middle East and North America also combined for a smaller 60 basis point decline against 2017 levels.

Most of the gains in the East Asian share were driven by China, which has managed to grow domestic refining capacity by just under 3 mb/d over the past three years. These gains have allowed the country to rapidly increase seaborne clean product exports. In 2019, seaborne departures leaving the country finished at a record 1 mb/d, up 367 kb/d from two years earlier, by far the largest increase of any country globally. Only Russia (+205 kb/d) and South Korea (+179 kb/d) even came close to rivalling the increase in volume leaving China.



Middle East seaborne clean product exports towards East Asia and Europe, kb/d



Source: Kpler

The Middle East is one of the largest exporting regions for clean products globally, an unsurprising reality given the intensity of oil production and refining within the region. In 2019, seaborne clean product exports of Middle Eastern origin finished the year at 2.69 mb/d, accounting for 16 per cent of the global total. The rise of East Asia as a dominant clean products exporter is a distinct problem for Middle Eastern producers who have long relied on purchasers in China, South Korea, Taiwan, and elsewhere to take on clean product volumes. In 2019, Middle Eastern producers exported 544 kb/d in clean product barrels towards East Asia, a notable decline against levels from 2017 and 2018.

As a result, Middle Eastern clean product exporters have adjusted by shipping more volume towards West of Suez markets. In 2019, departures headed for Europe and the Mediterranean finished at 800 kb/d, up by some 117 kb/d against 2017 levels. This was especially pronounced in Western Europe with loadings headed towards the subcontinent managing 344 kb/d in 2019, 66 kb/d higher than two years earlier. Interestingly, this trend was not maintained into 2020 given the spread of COVID-19. Middle Eastern shipments towards Europe and the Mediterranean ended at just 575 kb/d, with product departures once again prioritizing East Asian markets, which recovered to 629 kb/d, itself a significant increase from 2019 levels. Clearly the likes of Saudi Arabia and the UAE leaned heavily on East Asian partners to store excess products through a pandemic period that dragged on consumption across the globe. This short-run boost in product flows to East Asia is unlikely to be sustained as the demand for gasoline and diesel elsewhere slowly returns.

Middle Eastern clean product exports and a market-based approach for ME IOCs

Saudi Aramco, via ATC (Aramco Trading Company), is keen to establish a trading presence to capture more value from its crude and product outputs. The strategy implemented by ATC represents a significant change in operating model for the supplier. Rather than selling refined products (in particular) on a free-on-board (FOB) basis the firm, working alongside India's Reliance, now prefers to sell delivered cargoes to its buyers and take advantage of changes in geographical, temporal, and chemical arbitrage economics. This change of control over delivery means that Reliance and ATC can optimize their output far more effectively, while simultaneously enjoying a higher percentage retention of said optimized trading profits for themselves.



Reliance, for example, will contract to supply a gasoline short in New York harbour, but the barrels may never actually come from Jamnagar. Similarly, ATC may contract to supply Ultra Low Sulphur Diesel to Australia, but the molecules themselves may well come from South Korea (where they have a majority stake in refiner and marketer S-Oil), or from any other profitable supply source, and not necessarily from Yanbu or Jubail.

By expanding its reach into delivered products markets via its recently established trading arm, ADNOC Global Trading (AGT), ADNOC aims to emulate Reliance and ATC in controlling more of the optionality that has historically been given away to traders. If this activity is to expand into ADNOC's crude supplies as well, it will indicate a significant shift in market dynamics, precipitating a further change in East of Suez flows.

It is likely that other NOCs within the region will follow suit after witnessing the increased presence and enhanced revenues of these pioneers. Companies like Kuwait Petroleum Corporation (KPC) in Kuwait and the State Organization for Marketing of Oil (SOMO) in Iraq are likely to develop or recruit their own trading capability in an effort to take a larger share of the value in the supply chain. Product flows will continue to evolve according to the market needs of supply and demand, but in years to come the control of those flows may be in different hands.

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THE DUBAI BENCHMARK: EVOLUTION AND RESILIENCE

Dave Ernsberger

The Platts Dubai benchmark is entering its fifth decade in 2021. As it turns 41, Dubai is experiencing a surge of fresh vitality. In its entire history, there has never been more spot crude oil available for physical delivery into the benchmark than in mid-2021, when the removal of destination restrictions on UAE crudes from Abu Dhabi ensured full deliverability of Upper Zakum and Murban into the benchmark. In addition, volumes of Dubai derivatives trade have hit fresh record levels throughout the past year. As the Middle Eastern crude oil markets grow more diverse and competitive, mainstay benchmarks like Dubai become more relevant and necessary to understanding market dynamics.

Dubai's evolution as a medium sour crude benchmark has ensured that it constantly adapts to new market realities, like those we now find in 2021. For example, Murban is a new physically delivered futures contract in the market but Murban, as a crude oil stream that saw some of its volumes trading freely in the spot markets, has been a core component of the Platts Dubai and Oman benchmarks for half a decade already. While lighter and sweeter than other grades delivered against Dubai, Murban has been a deliverable grade of crude for both Platts Dubai and Platts Oman benchmarks since 2016, usually with a Quality Premium to be paid by the buyer to the seller to account for the quality difference when necessary. This ensures substantial deliverable volumes for both Platts benchmarks.

The new Murban contract's likely relationship with the Dubai benchmark is not only already well known through observation and analysis, it has also been the subject of informed research and debate, including previous papers by various authors at the Oxford Institute of Energy Studies.

Dubai's ability to respond effectively to new market norms, and its resilience in the face of constant market unpredictability, are the true source of its value to producers, refiners, traders, and derivatives markets around the world. It is the incumbent reference value in the Middle East and further afield for good reasons, and it is the benchmark against which most new crude contract initiatives are likely to be compared. But also, the Dubai benchmark itself is always on its toes, and has a long history of adapting to market trends so that it is strengthened, not weakened, by every new pool of physical crude trading that emerges in the region.

Open-source benchmarking

Crude production in the Emirate of Dubai dropped drastically in the 1990s, presenting the Dubai benchmark with its first true existential threat, and the formative experience that ultimately gave shape to its very strongest attribute—an ability to reflect not just one grade of crude from a single supply source, but the potential delivery of different grades of crude from across the region. The fullest history of Dubai's evolution on record is available in ['Yields vs. sulphur: What is driving crude benchmarks in 2020?'](#), a paper published with OIES in 2020 by Jonty Rushforth and Vera Blei from Platts.

When contemplating Dubai's likely success in the newly competitive markets, it always strikes me that its ability to incorporate relevant crudes from across the region is its very strongest asset. The five crude grades included in the Platts Dubai basket are:



Dubai, Oman, Abu Dhabi's Upper Zakum and Murban, as well as Qatar's Al Shaheen. Together, they now represent more than 3.5 mb/d of destination-free crude production available to the spot markets (see the illustration below).

Five deliverable crudes into Platts Dubai



Source: S&P Global Platts

When first confronted by plummeting volumes of production of Dubai crude oil, markets sought to handle the associated volatility risk by creating a formula of reference prices. The value of Oman crude was brought in alongside Dubai into a price basket, in particular for the Official Selling Prices for National Oil Companies, so there would be two reference prices, in a bid to shore up the total physical crude oil volume underpinning the resulting reference value.

But the limitations of such formula pricing become apparent very quickly—the more price components in an OSP, the less readily hedgeable it becomes. Even with just two price components in a formula, the complexities of managing price risk become challenging for the market; adding more beyond that would make reference pricing exponentially more difficult. Every price component needs its own derivatives market to allow for an effective hedge, something which self-evidently fractures liquidity and slowly undermines market confidence overall, rather than building on it.

A far better solution quickly emerged at the turn of the century. Rather than add more and more reference prices to a create an unwieldy mix of prices (and price risks), it was clear that it would be far better to strengthen a single, core price benchmark by including multiple streams of crude as being deliverable against the reference price. A *single reference price* supported by many crude inputs has reduced the risk of supply side disruption and built confidence, which in turn has allowed a deep derivatives market to develop, and also ensures that Dubai is consistent with both Brent and WTI, two other crude benchmarks that have, over their own histories, allowed for delivery of multiple crude grades to ensure that total physical volume in the benchmark is substantial and suitable for broad market use.

More than 20 years after Oman was introduced as a deliverable crude into Dubai, the Dubai benchmark is the only medium sour benchmark in the region that brings several relevant spot crudes into a single reference price. The only other medium sour crude contract in the world that has successfully mirrored this concept is the INE's crude futures contract in China; this raises the intriguing possibility that the Dubai benchmark, and the domestic futures contract serving the world's biggest seaborne crude buyer, could in time evolve to share broadly commensurate characteristics in a way that single-source benchmarks, especially if they prioritize national ambitions above broad market acceptability, won't.



Dubai’s open-source genetic code is a vital differentiator to other potential reference price offerings in the region. Before the Dubai benchmark itself can become stressed, every other component would have to become stressed, whether by a surge in buyer appetite, a shortfall in production associated with planned or unplanned maintenance, or by another logistical challenge. For Dubai to become challenged, the availability of every input into the benchmark—including Oman on the Dubai Mercantile Exchange and Murban on ICE Futures Abu Dhabi—would also have to have become challenged. By sharing market supply/demand risk among multiple grades, the core reference value at the heart of Dubai can remain relatively stable.

Other reference prices rely exclusively on a single grade of crude, with the aim that this will bring stability, but this in fact creates a false sense of security, a lesson learned by the Dubai benchmark more than 20 years ago. No matter how large a stream may be, a single grade of crude is never invulnerable, on its own, to anomalous events.

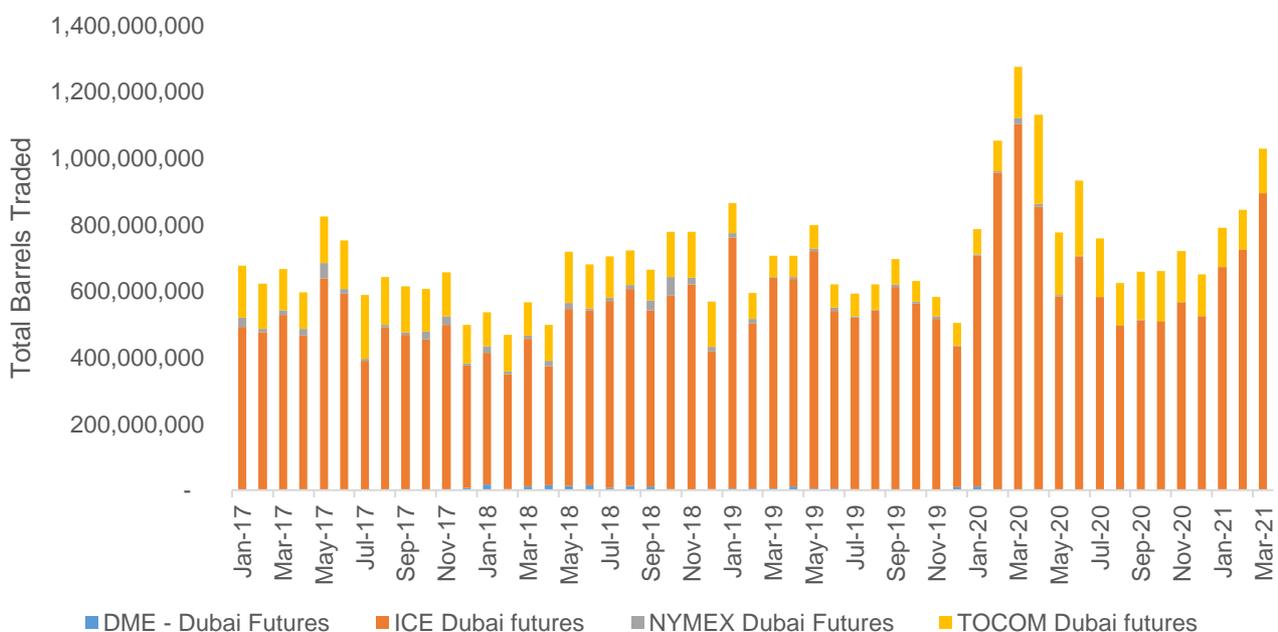
Open-platform hedging

One criterion often used to measure the success of a benchmark offering is liquidity in the associated futures markets. This is more meaningful than simple bragging rights. In fact, there are actually two key components of success in derivatives markets—liquidity and open interest, or depth, in positions held in forward contracts. Deep, liquid futures markets extending throughout a meaningfully long forward curve, are essential for any market participant to manage price risk along the supply chain that stretches from original producer to final consumer.

The Dubai benchmark has built a substantial amount of liquidity over the years, and trading volumes in Dubai futures regularly run at between 800 million and a billion barrels each month (see the chart below). Dubai futures volumes exceeded a billion barrels a month three times in 2020, and as recently as March 2021. While this is still a way off the volumes in Brent and WTI futures, these substantial volumes dwarf volumes in other medium sour crude futures, and allow for the ready hedging of medium sour crudes not just from the Middle East, but also from Russia and Latin America. In recent years, crude arbitrated from the US Gulf Coast to Asia has been benchmarked against Platts Dubai and then hedged using Dubai futures.

One of Dubai’s strengths, particularly looking ahead to the coming decade, is that it is available for trading on more than one futures venue. The lion’s share of Dubai futures trade on, or are cleared through, ICE Futures Europe, but volumes of Dubai futures also move through the DME and the CME Group. The second-largest volume in Dubai futures actually trades on Japan’s Tokyo Commodities Exchange through a Yen-denominated futures contract.

Trading volumes for Platts Dubai futures by exchange (total barrels traded by month)



Source: S&P Global Platts

Being openly available on multiple exchange venues is also core to Dubai’s continued relevance into the future. Market participants are often managing direct price exposure to medium sour crudes when dealing in Dubai futures, but even more



typically they will be managing spread differences between Dubai and other crudes (the Brent/Dubai spread is at the heart of global crude balancing), or Dubai-linked crack spreads at refineries. By being available at multiple venues, Dubai futures can be used by any number of market participants managing diverse futures portfolios with other crude and refined product futures, making margin calls increasingly manageable for market participants who may already hold positions at one clearing house or another.

The importance of hedging shouldn't be underestimated when evaluating the likely evolution of crude benchmarks in 2021 and beyond. For those studying these questions closely, it is often the most studied visible signal that there is.

This has observable impacts on benchmark pricing. On 14 April 2021, the first spot trades observed in the market for June-loading Murban and Das Blend cargoes were reported at Dubai plus 1.80 \$/bbl and Dubai plus 1.50–1.60 \$/bbl, just a few weeks after the Murban futures contract launched.

In March 2021, both Murban and Das Blend were reported by traders as traded for May loading in the spot market at OSP plus 20 cents/bbl each. The shift from OSP-based pricing for May loadings to Dubai-based pricing for June loadings came as ADNOC's OSPs themselves switched to become fully based on the futures contract, which settles two months in advance.

The associated disconnects in time, pricing, loading, and hedging meant it became more efficient for spot deals to be done on a Dubai basis, which can be efficiently hedged for both crude pricing and crack spreads, instead of the traditional OSP basis, which for now at least, can no longer be.

Looking ahead

With a new exchange contract arriving on the scene and vying for attention in the Middle East crude market, this decade will bring another competitive period for reference pricing and derivatives trading. Competition is good, and that maxim is as true for benchmarks as it is for any other industry. Those who have long said that the region needed an exchange of its own must be thrilled that the region now has not one, but two venues for crude contract offerings.

The Dubai benchmark benefits from exchange trading in both Oman Blend on the DME and Murban crude on IFAD, and indeed serves as a vital counterpart to those exchange contracts, by providing a possible further delivery mechanism for physical crude bought on the exchanges, should exchange participants need to offset or deliver those positions into the wider spot market in general. The Dubai benchmark brings both those crudes together into a single marketplace, along with other freely traded crudes from the region.

Dubai will adapt and evolve to make the most of these new market conditions—as it always has—to ensure that it continues to provide the markets with a reliable, accessible, and hedgeable reference price for medium heavy sour crude oil. Even in the few short weeks since IFAD launched its new Murban futures contract, we have seen trading patterns evolve to adjust to this new market reality, demonstrating how markets crave certainty in times of unpredictability.

To look back over Dubai's evolution since we first published a Dubai crude oil assessment from New York City in 1980 is a useful lens for observing the history of Middle Eastern crude markets in general, particularly the ebb and flow of national interests in pricing economics. These days, our Dubai benchmark reflects real-time market data provided by market participants in Singapore, Dubai, Geneva, London, and all around the world. The story of Platts Dubai also illustrates how benchmarks must be ready to adapt to the rising and falling fortunes of those who produce crude, and make it available for free trade and export.

MIDDLE EAST AND ASIA OIL PRICING—BENCHMARKS AND TRADING OPPORTUNITIES

Paul Young

Evolution of oil trading in the Middle East and Asia

Since the 1970s the Middle East has been a key power in terms of oil politics, production, and reserves, but it had more of a backseat role when it came to day-to-day price discovery, or in developing the region as a major trading hub along the lines of North West Europe, the US Gulf, or Singapore.

The last few years, however, has seen something of an overhaul of the way in which companies price and trade oil. National Oil Companies (NOCs) are increasingly looking for innovative ways of pricing and trading crude oil, including a much broader endorsement of oil futures contracts which are taking a central role in the trading of crude oil and refined products. Additionally,



Fujairah is developing into a major oil storage and trading hub, while Oman's Duqm refining/storage project will further underpin the region's infrastructure from 2022.

The growing adoption of futures benchmarks for crude oil sales into Asia has been underway since 2007, when Oman's Ministry of Oil and Gas (MOG) switched its Official Selling Price (OSP) to the monthly average of Oman futures traded on the Dubai Mercantile Exchange (DME). Since then, Saudi Arabia, Kuwait, Bahrain, and Dubai have also switched and use DME Oman oil futures in the underlying pricing formula.

A number of NOCs have also formed trading companies, with the likes of Aramco Trading Company, ADNOC Trading, Qatar's QP, and Oman's OTI now being major participants on global oil and gas markets.

More recently, ADNOC became the latest to fully endorse oil futures, listing its flagship light sweet Murban crude as a futures contract on the IFAD Exchange; this will be used as the underlying price for all its production. ADNOC's switch to 100 per cent pricing against Murban futures firmly tips the Middle East balance towards futures markets, with Iraq and Iran now the only major regional oil producers not fully, or partially, using a futures contract to construct OSPs.

Crude oil quality and pricing

Oman Blend is a medium sour crude, representing the majority of Middle East crude oil production, which is typically on the heavier side. Oman has been a key benchmark crude and reference price in the Middle East for several decades, with NOCs using Oman in pricing formulas since the 1980s. Additionally, Oman is a major component of Dubai pricing, while the DME has played host to the Oman futures contract since 2007. Oman is also a deliverable grade into Shanghai's INE sour crude contract, broadening its range in Asian benchmark pricing.

The grade is one of the largest freely traded crude streams in the region, with a production capacity of around 1 mb/d and exports of over 800 kb/d.

Broadly speaking, North Sea crude is predominantly light sweet, while in the US most onshore production is light sweet and the Gulf of Mexico offshore production is sour crude. When choosing a benchmark, buyers and sellers will look for a close match in terms of quality, but also consider other factors such as geographical proximity.

Historically, lighter crudes have commanded a premium over heavier Middle East barrels, but that premium has been steadily eroded in recent years as light sweet crude becomes more abundant due to burgeoning US production on the light sweet side, while sanctions against Iran and Venezuela have tightened supplies of sour crude. More recently, the OPEC+ producer group has held barrels back until demand returns and markets look more balanced.

Over the last two years the price of Brent futures has often dipped below Oman futures (and even Dubai), especially during the COVID-19 pandemic when demand for road transport fuels declined sharply. Light sweet crudes have higher yields of gasoline and diesel and therefore less need for additional processing. The balance has tipped back towards Brent in 2021, but is likely to remain unpredictable going forward, with many factors in play.

Futures markets and arbitrage

The expansion of derivatives, particularly futures contracts, has been a major factor in driving arbitrage; it also allows refiners greater opportunities for hedging and for comparing the broader array of crudes on offer.

One such example took place in the second quarter of 2020, coinciding with the height of the pandemic and oil prices collapsing to 20-year lows.

China led the demand recovery not just for Asia but globally, as it imported record volumes of crude oil over the summer months. At one point there was a spread of around 10 \$/bbl price difference between Middle East medium sour crude and China's INE sour crude contract.

DME Oman can also act as a proxy hedge for other Middle East medium sour grades—such as Basrah Light, Upper Zakum, or Qatar Marine—and some 40 million barrels of Middle East medium sour were delivered via INE. Around half was Iraq's Basrah Light, with the balance made up primarily of Oman and Upper Zakum.

Having the ability to lock in a pricing differential between the producing and consuming region via futures markets is a major enabler of such arbitrage opportunities.



Likewise, refiners can also compare and hedge crude oils priced on a different basis. Asian refiners sourcing global crudes can easily contrast and compare values of DME Oman against WTI or Brent futures, calculating which grades represent the best value. US export grades, in particular, have made waves in Asia, with South Korea, China, and India all major buyers.

Evolving crude oil benchmarks

While there is no agreed figure on the quantity of production a crude oil grade needs to be considered as a benchmark, generally the higher the volume the better—but only if the grades are consistent.

The US WTI benchmark was the first to allow delivery of alternative grades, but other pricing benchmarks, including Dated Brent and Dubai, have been transformed into a basket of crudes with multiple grades available for delivery. As these work on a seller's option basis, the choices of alternative delivery grades are critical for the market, since the lowest-priced grade will set the value of the benchmark on any given day.

Dubai production has declined from around 400 kb/d to less than 50 kb/d now, but has been supplemented over the years, initially with the similar-quality medium sour grades Oman and Upper Zakum, and followed later by another medium sour, with Al Shaheen and the light sweet Murban crude.

Although Murban is a different quality crude, it was not seen as contentious when introduced as a deliverable grade into the Dubai basket; at the time Murban commanded a healthy premium over medium sour grades, so it was envisaged there was little possibility of Murban ever being the lowest of the five grades. Fast forward to 2020 and the COVID-19 pandemic—Murban became the 'price setter' for Dubai.

The 2020 demand collapse was primarily in transportation fuels (jet, diesel, and gasoline), which light sweet crudes are geared towards producing. Light sweet crudes moved to a steep discount against medium sour grades, and this included Murban falling to multiple-dollar discounts against Oman. At the peak of the demand/price collapse Murban was trading at a discount of more than 5 \$/bbl to Oman—therefore valuing Dubai at 5 \$/bbl below DME Oman.

The Murban disconnect coincided with oil prices trading at 20-year lows, so a 5 \$/bbl disconnect on 20 \$/bbl oil would potentially lead to a hedging position being 25 per cent off market.

This highlighted the importance of matching hedging to the underlying exposure, rather than against a different benchmark. In short, to fully mitigate price risk, buyers and sellers should choose the correct underlying benchmark, which for Oman, or grades priced against Oman, is the DME futures contract.

The alternative-grade conundrum

This disconnect between light sweet and medium sweet crude caused the market to pause for thought, and feedback from DME stakeholders was that Murban should not be considered as an alternative delivery grade for Oman, or certainly not in a 'lowest-price-wins' methodology.

Oman as a benchmark has been fortunate in that production has been maintained around the 1 mb/d mark, but this does not mean that alternative delivery grades should not be considered. In recent years DME has engaged in many detailed discussions with stakeholders, who made it clear that any such action needs careful consideration.

Market evolves towards spot trading

One of the biggest changes in crude oil markets in the Middle East and Asia in recent years is the transition from a largely term-contract driven marketplace to one with highly liquid spot markets and key price-discovery centres at both export and delivery hubs, all supported by sophisticated derivative instruments.

As East of Suez refiners embrace these changes, spot crude trading and variable refining slates have become a major feature of the market. Refinery buyers these days typically consider a much broader array of crudes, factoring in pricing differentials and crude yields to maximize efficiencies.

While baseload refinery demand will still typically come from reliable and favoured suppliers, with a high value placed on security of supply, refiners are increasingly looking to the spot market to supplement baseload grades. On the broader picture, refiners and traders will factor in crudes from all around the globe, with the underlying benchmarks playing a key role.



As markets evolve, price discovery becomes an increasingly important element, and among Middle East grades, buyers will work out pricing differentials and product yields. Price discovery around Middle East crude has primarily centred on medium sour grades, which represent the critical mass of production capacity of more than 25 mb/d in the region.

Introducing ACE—an alternative-delivery grade solution

Protecting the integrity of the key reference price is a major consideration when introducing another grade into a benchmark. The obvious choice is to add a grade very similar in quality and value, so the price is reflective of the base grade. Otherwise, a formula needs to be applied to realign the alternative delivery grade with the base grade—but the greater the differences between the grades, the more potential there is for price volatility.

In order to avoid the potential for price distortions, DME will take a new approach to introducing alternative grades into the OQD Oman contract, whereby the value of the base grade will not be distorted.

The Alternative Crude Ecosystem (ACE), launched by DME in the second quarter of 2021, is a bilateral trading platform which enables transactions between other Middle East crude grades and Oman, with price differentials against DME Oman crude futures. The majority of East of Suez refiners/traders already have DME Oman pricing exposure, with over 5 mb/d of FOB Middle East crude priced directly against DME Oman.

The initial batch of grades selected for the ACE platform are Dubai, Upper Zakum, Murban, Basrah Light, Basrah Heavy, and Al Shaheen, but other grades will be considered going forward. The new ACE platform allows participants to trade between the grades on an Over-the-Counter (OTC) basis, with price discovery available on a transparent platform.

ACE will utilize well-established pricing mechanisms derived from the DME Oman futures market. This pricing will offer a common and transparent baseline price for the market to price differentials against other bilateral Middle East grades, with the backing of a cleared futures transaction via a regulated Clearing House. Crucially, the price of DME Oman will always reflect the value of Oman, as the differentials versus other grades will not in any way alter the Oman base price.

While trading between different types of crude and grade substitution is a growing trend in East of Suez markets, typically such transactions are conducted directly between the two parties. Even physical oil brokers are rare in Asia, and near non-existent in crude, so the ACE platform will add a new dynamic in transparent pricing for grades that historically have traded in relatively opaque markets.

The ACE platform is the first of its kind and will consolidate Oman’s role as the key medium sour crude pricing reference for the Middle East and beyond. The Oman benchmark fully reflects the fundamentals of East of Suez crude markets, and as refiners broaden crude slates, regional benchmarks become increasingly important on a global basis.

So, while comparing Oman in the Middle East against Brent or WTI Midland is already an industry standard with easy price discovery, DME’s ACE platform will open up pricing differentials between Middle East grades and bolster Oman’s role in price discovery on global crude markets.

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THE PROSPECTS OF MURBAN AS A BENCHMARK

Michael Wittner

On 29 March 2021, ICE Murban crude oil futures began trading on the new ICE Futures Abu Dhabi (IFAD) exchange. Nine of the world’s largest energy traders have joined ICE (the exchange operator and majority shareholder) and ADNOC as founding partners in IFAD; these partners include BP, GS Caltex, INPEX, ENEOS (formerly JXTG), PetroChina, PTT, Shell, Total, and Vitol.

This article will examine the fundamental characteristics of Murban that should make it a successful benchmark. In addition, we will cover some of the key technical aspects of how the futures contract works. We will also discuss the uses of ICE Murban crude oil futures, how it fits into the global oil market, and its trading dynamics since launch.

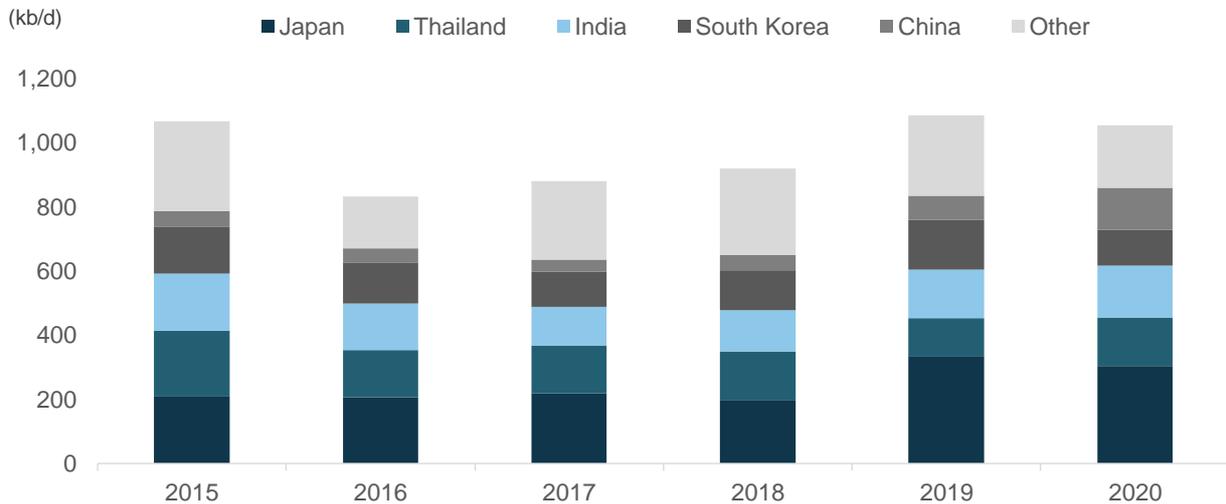
Fundamentals that support Murban as a benchmark

- High physical volumes: Murban has high, reliable, and stable volumes of both crude production and exports. Total UAE crude production capacity is currently over 4 mb/d. Of this, Murban production capacity, operated by ADNOC



Onshore, is around 2 mb/d. Murban exports averaged approximately 1.1 mb/d in 2019 and 2020, as shown in the chart below. Importantly, these volumes will provide physical liquidity to underpin ICE Murban crude oil futures and will be available for sale through the contract.

Annual Murban crude exports by destination (kb/d)



Source: Kpler

- **Future growth plans:** ADNOC plans to increase crude production capacity by 25 per cent to 5 mb/d by 2030. Murban production capacity is expected to remain about half of the total, and should grow from 2 mb/d to 2.5 mb/d. Murban exports should increase in line with production.
- **Ruwais refinery upgrade:** In addition to increasing production by 2030, a \$3.5 billion upgrade to the 817 kb/d Ruwais refinery is due for completion next year. Ruwais currently processes mainly Murban crude, but the upgrade will give it the flexibility to refine around 400 kb/d of heavier and more sour crude grades, including imports. This will increase the volume of Murban available for exports.
- **Transparent export plans:** In order to provide greater transparency and visibility on Murban exports, ADNOC now publishes monthly [‘Murban Export Availability Reports’](#), available on ADNOC’s website. This provides projected volumes of Murban available for export in the 12 months ahead.
- **High quality crude:** Murban is a consistently high-quality light sour crude, with API gravity of 39.9 degrees and sulphur content of 0.78 per cent. It is lighter and sweeter than most Middle East crudes, which are medium and heavy sour grades. Indeed, Murban is closer in quality to UK Forties (part of the Brent assessment) and US WTI.
- **Diverse group of sellers:** Importantly for the proper functioning of a benchmark, production and sales of Murban are diverse and not dominated by a single player. Alongside ADNOC (60 per cent equity production), other partners in ADNOC Onshore include BP, Total, CNPC, Inpex, Zhenhua, and GS Energy.
- **Diverse group of buyers:** Of equal importance, buyers are also diverse. Due to the high quality of Murban, it is attractive for refiners. As shown on the Murban exports chart above, essentially all Murban flows to refiners in Asia (including the ‘other’ category). Approximately 30 per cent goes to Japan, with roughly 15 per cent each going to China, South Korea, Thailand, and India.
- **Strong terminal/port infrastructure:** Murban crude is exported from Fujairah and Jebel Dhanna, near Ruwais. The majority of the current 1–1.1 mb/d of exports is from Fujairah, at around 840 kb/d. We focus on Fujairah here, because that is where physical delivery of Murban through the ICE Murban crude oil futures contract will take place. At this oil trading hub, three single-point buoy mooring points allow near-simultaneous loading of very large crude carriers (tankers).



- **Ample crude storage at Fujairah:** Another important factor for a crude benchmark is storage capacity at the physical delivery point. Existing crude storage capacity at Fujairah is 8 million barrels. However, ADNOC is currently building a new 42 million barrel underground crude storage facility, located next to Fujairah in the UAE's Hajar mountains. This facility, which will bring total Fujairah-linked crude storage to 50 million barrels, is due for completion in 2022 and will be connected to Fujairah by overland pipeline. The ample storage capacity at Fujairah will give ADNOC the ability to ensure uninterrupted physical liquidity for deliveries into the ICE Murban crude oil futures contracts; it also allows ADNOC to mitigate any impact from possible OPEC production cuts (more on this below).

Key changes to the Murban market

The launch of trading for ICE Murban crude oil futures was combined with two important and fundamental reforms in physical Murban pricing and physical trading.

On **pricing**, starting in June, the official selling price (OSP) for Murban will no longer be set as a differential to Platts Dubai assessments. Instead, it will be a transparent, market-driven, prospective price. Going forward, the OSP for Murban will be based on the monthly average of daily front-month Singapore Marker prices of ICE Murban crude oil futures in month M-2, where M is the month of loading.

For example, the price for Murban loading in June 2021 was based on the June ICE Murban crude oil futures contract, which was the front-month contract during the month of April 2021 and expired at the end of April 2021. The OSPs for ADNOC's other export grades—Das, Upper Zakum, and Umm Lulu—will be set as differentials to Murban; therefore, all of them will be based on ICE Murban crude oil futures.

On **trading**, ADNOC has removed destination and resale restrictions on all its crude, also starting in June 2021. They will be able to be freely traded and delivered in the global market.

These two reforms are designed to work with each other and also to work hand-in-hand with ICE Murban crude oil futures. The removal of destination and resale restrictions will boost physical trading in Murban and other ADNOC crudes, while the move to pricing based on ICE Murban crude oil futures will facilitate the use of those futures to hedge those trades and build trading volumes and liquidity in the new contract. In short, the market will freely determine the price based on the forces of supply and demand, and market participants will be able to hedge their price risk.

Features of the ICE Murban crude oil futures contract

Some key features of the new ICE Murban crude oil futures contract are described here. ICE Murban futures are screen-traded, physically deliverable at maturity, and currently cover up to 48 consecutive months. Each 1,000-barrel contract is priced in US dollars and quoted to 0.01 \$/bbl, the minimum price fluctuation. Trading of contracts ends on the last trading day of month M-2; again, the example we use is the June 2021 contract that expired at the end of April 2021. Traders holding contracts at maturity must deliver or receive Murban crude FOB (free on board) at ADNOC's Fujairah terminal during the delivery month M (June 2021 in our example); the volume tolerance for a Murban cargo is +/- 0.2 per cent.

A solid start for trading in ICE Murban crude oil futures

Due to the attributes of Murban discussed above, and its utility for hedging, as well as some early interest from financial investors, the first month of trading since the launch on 29 March has been a success. Daily open interest by tenor (in other words, contract maturity) is shown on the chart below. Since the launch, open interest has grown to over 40,000 contracts, spread over the first seven months of the futures curve (at the time of writing, M1 is the June 2021 contract and M7 is the December 2021 contract). Daily trading volumes since the launch have averaged 6,937 contracts.

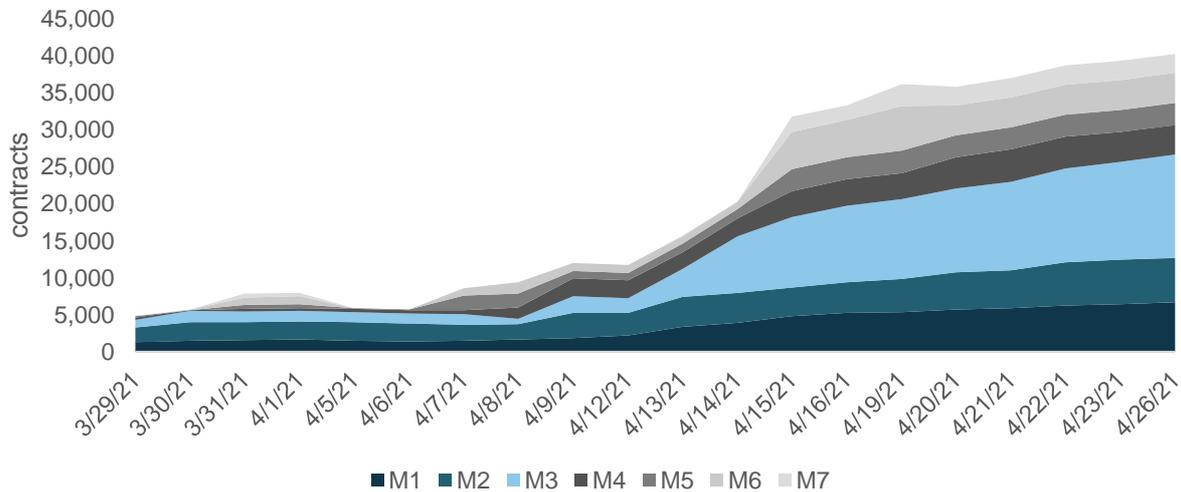
There are currently 49 participants trading ICE Murban crude futures on ICE Futures Abu Dhabi, of which 37 are commercial customers—producers, refiners, and trading companies—and 12 are financial participants. The 49 participants come from across the US, Europe, the Middle East, and Asia.

Most initial trading liquidity is expected to be related to hedging of Murban and other ADNOC export crude by producers, refiners, and trading companies. As liquidity develops, ICE Murban futures could serve to hedge physical trade for similar Middle Eastern crudes, and also other similar crudes traded into Asia, including WTI-linked US grades. To drive these changes, ICE and ADNOC have signed Memorandums of Understanding with several companies, to explore and assess the pricing of



crude trade using ICE Murban futures. These companies include China’s Unipec and Rongsheng Petrochemical, Japan’s Cosmo Oil, and Chevron, Trafigura, and Occidental; the latter three companies would potentially use ICE Murban futures to price US crude exports to Asia.

ICE Murban crude oil futures, open interest by tenor



Source: ICE

It should also be noted that IFAD has complemented the launch of ICE Murban crude oil futures with a series of tradable cash-settled spread instruments to other ICE crude benchmarks; these include Murban versus ICE Brent, ICE Dated Brent (Platts), ICE WTI, and ICE Permian WTI. Other instruments include refined product cracks versus Murban. ICE Murban has also been mentioned as a way to hedge LNG cargoes to Asia, where crude is a significant part of the pricing formulas. In short, based on the attributes described above, our view is that Murban will emerge as an important complement to Dubai.

In the final part of this article, we examine some questions on ICE Murban futures.

Will potential OPEC supply cuts mean that physical Murban volumes might, at times, be restricted?

As the UAE is a core member of OPEC, some have questioned whether potential OPEC supply cuts could occasionally restrict the flows of Murban crude that underpin the physically deliverable ICE Murban crude oil futures contract.

While this is a fair question to ask, there are some points to consider that give a more complete and balanced picture, and indeed that argue against OPEC policy causing Murban supply issues.

First, OPEC+ policy in the form of cuts or increases is about crude production; this leaves crude exports (that is, actual supply to customers and to the market) up to the discretion of the producer in the short term. When cutting production, the producer can cut exports by a smaller amount, by drawing from domestic crude inventories. The opposite also holds; when increasing production, the producer can increase exports less, by building domestic crude inventories. ADNOC has this flexibility, as do other key Middle East OPEC producers.

The second point follows from the first: as mentioned above, there is 8 million barrels of existing crude storage capacity at Fujairah, with another 42 million barrels due for completion in 2022. ADNOC has explicitly stated that crude in storage—and the amounts will be substantial—can be tapped as needed to maintain the physical trading associated with the futures contract. The 12-month production guidance that ADNOC publishes monthly is specifically to provide forward transparency—and reassurance—to the market, the message being that the production estimates can be supported with crude in storage, in the event of OPEC cuts.

What are the trading dynamics in ICE Murban crude oil futures?

With almost five full weeks of trading complete, the trading dynamics in Murban futures look appropriate for a brand-new market like this. The split between volumes of trades transacted via the central limit order book (so-called ‘on the screen’) and those conducted via ‘block’ trades is approximately split 50/50.



First let's explain what a block trade is. Block trades allow market participants to agree a price off-exchange, often in a large size. These trades bring liquidity, which attracts liquidity from other participants, and contributes to the volumes and open interest reported by exchanges.

Newer, less mature, markets typically see a high percentage of volumes conducted through block trades (a high percentage being more than 50 per cent), as price is discovered across a hybrid market model involving the central limit order book and broker-conducted trading. As activity in the order book for Murban futures grows, more and more of the activity will develop to be done on the screen; however, as we can see from the development of other energy benchmarks, this takes time.

For comparison, let's look at the block/screen trading split in other energy benchmarks. Volume in ICE Dubai (Platts) futures is around 42 per cent block trades, compared to 50 per cent a year ago. Exchange trading in TTF natural gas, coined as 'the Brent of gas', is now around 80 per cent conducted on the screen, but was closer to the 60 per cent mark only a few years ago. JKM LNG (Platts) futures, the Asian natural gas benchmark, is currently 90 per cent block volumes and 10 per cent screen-based volumes, reflecting the fact that this is a newer and developing market.

At the fully developed end of the market maturity spectrum, we have Brent futures which have traded for 33 years, and WTI futures which have existed for 37 years. These markets are approximately 90 per cent screen-based trading and 10 per cent block trades.

Murban futures are a brand-new market with very new levels of transparency brought through two key changes: the recent ending of destination restrictions by ADNOC, and the end of retroactive pricing—replaced by transparent futures-based pricing. Both of these reforms will help the development of a more active spot market.

As futures markets mature, screen trading typically grows relative to block trading. The examples above show that Murban's approximately 50/50 screen/block proportion sits comfortably in the middle of the spectrum. A fully mature market takes more than one month to develop.

IFAD: A LURCHING START IN A SANDY ROAD

Jorge Montepeque

ICE Futures Abu Dhabi (IFAD) announced the launch of Murban futures with a big fanfare on 29 March 2021. Even the buildings of downtown Abu Dhabi joined a dazzling display to announce the birth of a new futures wonder. As the Abu Dhabi Media office put it:

'Abu Dhabi's iconic buildings light up to celebrate the launch of ICE Futures Abu Dhabi (IFAD) ... a milestone event, helping to fuel the UAE's growth for generations to come.'

ICE was no shy wallflower, pronouncing:

'ICE Marks Historic Milestone in Global Energy Markets As The World's First Murban Crude Futures Contracts Are Launched on ICE's New Exchange in Abu Dhabi.'

The press release further stated:

'In making Murban a freely traded global commodity, it becomes even more attractive to market participants and will deliver greater value to ADNOC and its partners. This historic and strategic milestone reinforces the UAE and Abu Dhabi's status as a leading global energy hub and underscores ADNOC's central role as a catalyst to empower the UAE's economic ambitions.'

You could hear the drum rolls everywhere.

Key questions

But with two months since its launch and with liquidity still far from stellar, a few questions could be raised:

- Is IFAD performing according to the hyped expectations?
- Is IFAD, as early data suggest, facing the same low liquidity and reluctant market interest that the competing Dubai Mercantile Exchange (DME) is so familiar with?



- Who is going to trade the contract?
- And how are all the parties going to make money? Nobody trades for the sake of trading. There has to be an economic interest. Moreover, trading is a very low-margin business where cost and behaviour are monitored by financial and compliance hawks.

As the key Murban producer and exporter, ADNOC also faces some questions:

- What are the possible gains from the exchange?
- Will the exchange achieve reasonable returns?
- Has ADNOC become more or less efficient since IFAD was launched?

This article explores some of these questions.

The challenge of attracting liquidity

Historically, attracting liquidity to a new contract has not been easy. Over the past 25 years, there have been over 10 attempts to crack the Middle East crude nut. Singapore has tried and so has Japan. Shanghai’s INE is probably, in terms of volumes, the most successful of the lot. But none has been a slam dunk.

It is early days, but it is interesting to see how exchange volumes compare. The IFAD contract is still new, so the comparison (in the table below) is early, but it is illustrative.

Total lots traded ('000 bl)—29 March to 30 April 2021

CME WTI	ICE Brent	DME Oman	IFAD Murban
21,308,055	19,794,604	103,935	144,531

Source: Various Exchanges

Clearly, despite all the recent razzmatazz, volumes in the Middle East are a minuscule side show. The elephants in the room are ICE Brent and CME WTI, and their lookalikes. Both the elephants have been extending their trunks into new markets, with DME and IFAD just an extension of the traditional CME–ICE competition.

CME and Oman have spent significant resources trying to turn DME’s Oman into a major global benchmark, but the dart did not hit a bullseye. The market has not provided all-day liquidity; DME is generally snoozing with an occasional stirring.

Abu Dhabi, ICE, and partners clearly expected instant success. But in business, like war, nothing ever goes according to plan. Liquidity has been underwhelming, the bid–offer spread is too wide at critical times, and there is minimal book depth.

The attraction of starting an exchange

Based on decades of observation, it is fair to say that launching a futures contract is painful work, full of hope but statistically likely to fail. Some exchanges do hit the jackpot, hence the attraction for newcomers. As one source put it, ‘maybe 10 successful contracts provide over 80 per cent of the volume to all exchanges.’ But exchanges list hundreds if not thousands of futures contracts, which at best just mark time.

So why the expectation of immediate success in Abu Dhabi? Everybody knows and analyses the core production numbers. The Middle East is the biggest basin of crude in the world and even with current COVID-constrained demand and self-imposed OPEC discipline, output from the region may exceed 22 mb/d. This is roughly twice US production and many times the output of the North Sea.

But then it gets tricky. Some of that production goes West and uses Western crude benchmarks. In addition, an increasing chunk is refined domestically/regionally or within joint foreign-based ventures. This reduces the total theoretical hedgeable amount.

It is hard to imagine NOCs hedging and spending money on fees, margining, and other ancillary expenses. So, if you subtract Western exports and domestic refining requirements from total production, you end up with a net ‘potential’ hedgeable amount—the volume that could power a futures market—of no more than 13 mb/d. Then there is the additional nuance of different crude grade qualities, the tendency for some buyers not to hedge and, to top it all, the clear enmity between some countries. It is not easy to navigate one’s way to futures riches while facing these constraints.



Both Oman with the DME, and Abu Dhabi with IFAD, have recognized these shortcomings, and both are powering their exchange with their own crude production, hoping other nations eventually take notice and tack their fortunes to them. The DME has extended its reach significantly over the years, attracting key player Saudi Arabia, which switched 50 per cent of its Asian pricing to the DME. Other neighbouring states followed, yet DME volume remains limited and rarely exceeds 5,000 lots per day.

The table below shows the price basis for crude oils sold East of Suez from the Middle East:

Country	Pricing benchmarks	
Saudi Arabia	DME Oman	Platts Dubai
Kuwait	DME Oman	Platts Dubai
Iran	Platts Oman	Platts Dubai
Iraq	Platts Oman	Platts Dubai
UAE	IFAD Murban	Platts Dubai
Qatar	Platts Oman	Platts Dubai
Bahrain	DME Oman	Platts Dubai
Oman	DME Oman	
Dubai	DME Oman	

Source: Author’s compilation

Total physical exposure to DME Oman is likely around 5 mb/d, while exposure to IFAD is around 2.6+ mb/d, which is Abu Dhabi’s total production. But from this 2.6 mb/d, the capacity of the Ruwais refinery should be subtracted as this volume is not hedged, leading to a net number in the range of 1.7 mb/d. Clearly, Abu Dhabi must be lobbying Saudi Arabia to switch from Platts or the DME or both.

Despite the exchanges, Platts Dubai remains the preferred benchmark to trade as a spread versus Brent, WTI, or as the basis for further hedging and other price management in refining margins and speculation. There are two key reasons for Dubai’s importance as a hedging instrument: it happened by market force and it enjoys the benefits of incumbency.

Unintended consequences

In fact, in an unexpected and eye-opening move, spot Abu Dhabi crude trading in April 2021 moved away to a Platts Dubai basis and away from the official prices for June cargoes. Spot transactions for Abu Dhabi grades have historically traded either linked to the OSP or linked to Dubai. But in April, following the launch of IFAD, spot transactions based on Dubai actually increased, while those based on ADNOC OSPs decreased. This movement away from spot OSP linked trading has continued in force in the May trading cycle and traders expect similar trading behavior going forward.

Murban, Upper Zakum, Das, and Umm Lulu compete against other grades which are measured on a Dubai basis. Customers do not want to have a different flat-price exposure. Traders also noted that they had shifted more sales from the ADNOC OSP to Platts Dubai because buyers want to buy the crude priced on the Dubai benchmark on the month of loading rather than facing the retrospective flat price exposure of ADNOC OSPs.

The diminished importance of OSPs for spot trading is an example of the law of unintended consequences. The ADNOC OSP now only matters to those locked in long-term transactions. The OSP has become nothing more than an interesting trailing historical artefact that has been superseded in the spot market by daily and present market forces.

As a real-life example, IFAD sets its June Murban OSP at the end of April, but June spot Murban traded around the middle of April for cargoes loading in June. Those June Murban cargoes did not trade OSP-linked, instead the transactions noted by General Index were all Dubai linked! This trend is likely to continue. If you were ADNOC or ICE, you would be scratching your head and wondering what happened.

Technically, there is nothing stopping the market from trading spot ADNOC grades linked to the forward Murban front quotes in



June rather than the OSP. But old habits die hard. This could result in third-party equity producers having to hedge their grades twice, if not more, as they switch from one basis to another. And all of this costs money.

The DME has also bumped against the same incumbency and familiarity privileges enjoyed by Platts Dubai. IFAD has it worse, because it is bumping against those same privileges and also against DME Oman's toehold which, after the Saudi support, has become a beachhead.

The question for everybody who cares about Gulf pricing is whether Saudi Arabia will use IFAD in its pricing formula? The Saudis are measured, and recently said that they react to their customers' wishes. Nobody should expect any changes quickly. But a full-on Saudi move to IFAD would cut Platts Dubai and DME Oman off at the knees.

There is liquidity, but only briefly...

DME sees a burst of activity around its settlement time of 4.30 p.m. Singapore time. Trading happens at this time because the number generated then powers term and spot contracts. But after the 4.30 p.m. burst, the DME is comatose or in suspended animation until the next day's brief frenzy.

ICE and Abu Dhabi seem to be facing the same issue. Murban is active around 4.30 p.m. and the rest of the time the market is asleep with the occasional stir, one lot here and another lot there.

The Dubai partials market exhibits the same time-concentrated trading behaviour in the window with a distinct additional feature, its volume is a lot lower than in the exchanges. During April 156 partials were done, amounting to 3.9 million barrels or equivalent to 3,900 lots or less than what an exchange -IFAD or DME would trade on a typical day.

Physical, or near physical, markets such as Dubai, DME, and IFAD have minimal liquidity, yet their power and influence is very large. It is very frustrating for businessmen who try to pry liquidity away and convert it large volumes in a futures market.

In real life observations of the Asian/Middle East trading mechanisms, the effective liquidity lasts between one and five minutes! This contrasts with better-functioning futures contracts, like ICE Brent and CME WTI, which trade anytime and all the time.

Fees and revenues

To paraphrase a knowledgeable observer, IFAD is 'repeating the same mistake that the DME made by claiming it would take over the world'. In his opinion, IFAD should reduce its ambitions and focus on making money. But making significant money is difficult, given the volume DME currently trades, or the volume reported by IFAD which many consider unreliable and fluffed up by market makers/supporters.

The main source of revenue for an exchange is 'fees'. There are other revenue streams but the primary fees relate to trade execution.

If we take the exchange-listed fees at face value, given the volume so far recorded, the resulting revenue would be almost dismissible. IFAD charges \$0.82 per lot of 1,000 barrels and the DME \$1.35 or \$0.75, depending on membership status. This means that IFAD's revenue is \$820 for every million barrels traded. Clearly, in order for significant revenue to occur, millions and millions of barrels need to trade. This is not happening. And it is important to stress that in essence, the theoretical profit (most surely loss after all expenses are counted in) from the endeavour needs to be shared between ICE, IFAD, and the other investors. Not an initial good return on investment.

The number of trades in IFAD has been very low and the exchange has only had five days with activity over 10,000 lots, with a peak of nearly 19,000 lots. These peaks have resulted in celebratory press releases. This sounds good but the wet blanket throwers say that the volume should be further scrutinized, as most of it was a function of entities posting transactions that were arranged off exchange. These deals fall under the 'block transaction' denomination.

On the day with nearly 19,000 transactions, over 14,000 were block trades. The net was only 4,102 transactions. The graph below shows the percentage of block trades relative to screen trading, and just how random their distribution is.

A typical transaction that would inflate volume—and we are not saying it has happened—would work in the following way: a trader would 'buy' October Murban, or whatever commodity, from a willing counterparty, say 6,000 lots, and sell back 3,000 lots each of September and November. This results in 12,000 lots of trade. The market makers have thus traded a lot of volume with minimal flat price exposure. We heard of market makers engaging in similar practices in the early years of the DME.



Trade Date	Murban	Blocks	Net Murban
29 March 2021	6,344	5,000	1,344
30 March 2021	2,934	1,500	1,434
31 March 2021	3,196	2,000	1,196
1 April 2021	1,479	-	1,479
5 April 2021	3,636	2,000	1,636
6 April 2021	2,194	95	2,099
7 April 2021	14,419	12,050	2,369
8 April 2021	12,086	10,900	1,186
9 April 2021	12,324	4,400	7,924
12 April 2021	2,988	-	2,988
13 April 2021	9,871	4,514	5,357
14 April 2021	8,029	3,100	4,929
15 April 2021	16,305	13,224	3,081
16 April 2021	3,131	-	3,131
19 April 2021	7,773	4,000	3,773
20 April 2021	18,798	14,696	4,102
21 April 2021	4,228	-	4,228
22 April 2021	3,339	500	2,839
23 April 2021	2,817	400	2,417
Total	135,891	78,379	57,512

Source: ICE, General Index

All this nuance escapes the PR machines for IFAD, DME, and Platts, which are all in overdrive.

The DME announced on 5 April that it was launching a new system: the 'Alternative Crude Ecosystem (ACE)—a new bilateral trading platform to enable participants to trade multiple crude grades through the exchange.'

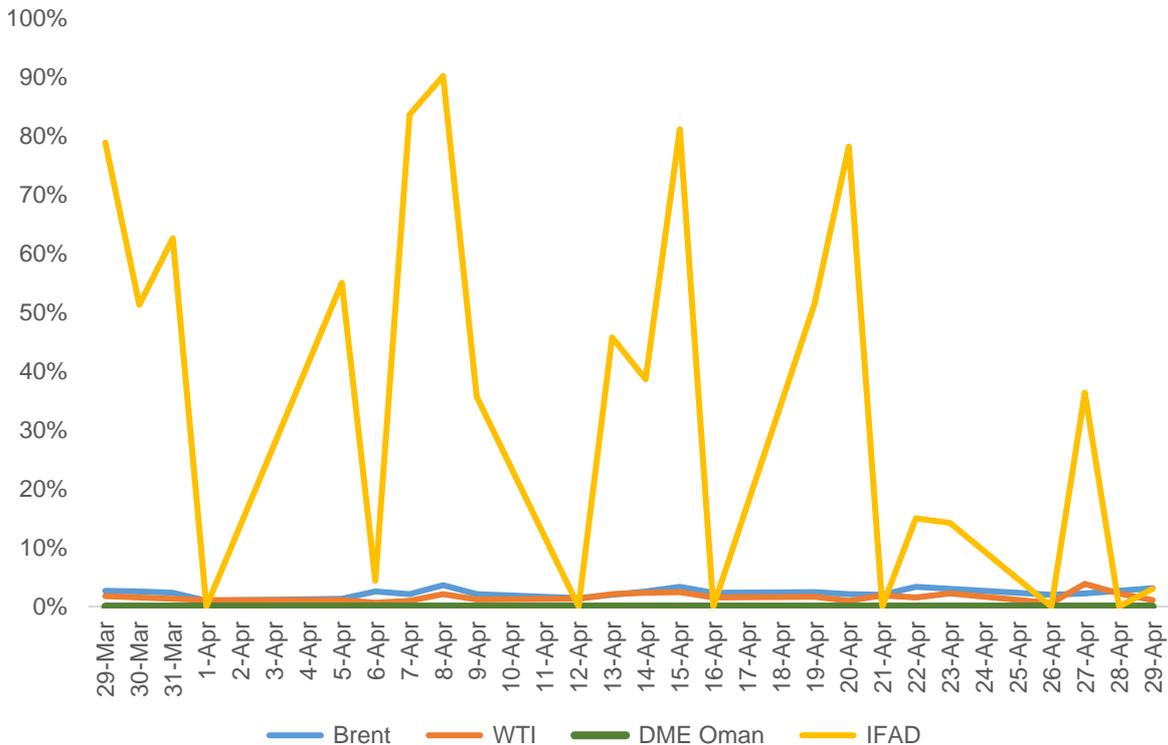
The next day saw Platts promoting the trading health of the Platts Dubai derivatives contracts: 'Across the forward curves, the combined trading volume for ICE Dubai futures contracts—including the Dubai first-line futures, the Dated Brent versus Dubai 1st Line futures, and the Brent 1st Line versus Dubai 1st line futures—was 892,766 lots in March, ICE data showed April 1. One lot is equivalent to 1,000 barrels.'

Competition in business is very tough and any incumbent enjoys an inherent advantage. Everyone wants to go where the party is already happening. There is nothing worse than being the first at a new club with too many welcoming hosts. The ecosystem of exchange support, clearers, bankers, speculators, hedgers—all the partygoers needed to make an exchange successful—are already present in Brent and WTI. Nobody wakes up wondering where is the flat price of Dubai, Oman, or Murban. They wake up asking where is Brent or WTI.

Brent and WTI are the big stars, and then you have the planetoids and other interstellar debris such as the IFAD, TOCOM, and DME, whose fate is inextricably linked to the big stars. Like a black hole sucking in the dust and matter of a nearby body, the life of any small market is eventually drained out or controlled through the tight embrace of a Brent/Dubai or Brent/Murban spread.



Blocks as % of total futures by exchange



Source: Various Exchanges

Requirements for success

IFAD needs a break, literally a market break, such as Brent going through an existential issue, which it did when Platts injudiciously announced that it was planning to switch the benchmark basis from FOB to CIF. ICE Brent could have become collateral damage in the process. Other opportunities might come if the DME runs out of steam, or Platts Dubai suffers more wobbles, as happened in 2020 when it was impacted by yet another injudicious action, the addition of sweet Murban to the Dubai sour basket.

Incumbency sometimes leads to complacency, so maybe ‘the break’ could happen. But barring any big screw ups, the horizon offers slim pickings for IFAD.

The removal of destination restrictions was a step in the right direction, which definitely enhanced the tradeability of the Murban cargoes. But it is possible that this move came with a cost for ADNOC, which used to charge roughly 15 cents/bbl for the privilege of being able to redirect a crude cargo.

ADNOC also needs to ensure there are no changes in the volumes assigned to its equity partners or term lifters for at least two months ahead. Any random or out-of-schedule changes for volumes loading in M+2, for instance June cargoes during April, would impact the hedges in IFAD positively or negatively, and equity partners and lifters do not like randomness at all.

But this also comes at a cost, as Abu Dhabi’s hands are tied on one side by the need of its clients to have volume certainty to use IFAD effectively. And on the other, the country has commitments to OPEC that may pull Abu Dhabi in a contrary direction, forcing the country to make a Faustian choice.

There are some improvements that IFAD could make, while it is waiting for a break, such as reducing the financing costs faced by lifters from the exchange. Depending on the time of load, a buyer faces a cost of 7 cents/month/bbl of extra financing. This could amount to 21 cents if the cargo is a late month loader, due to the fact that the clearer will need to hold a dollar amount equal to the cargo to be loaded. Sellers also face margining issues. IFAD does not accept letters of credit, making its deliveries more expensive. This additional cost of delivery is on top of other exchange fees.



ADNOC needs to be aware that exchanges bring extra costs in terms of financing/margining, compliance, regulations, and more people circling in the wings trying to extract little bits of value here and there. This is a challenge for ADNOC, who initially saw IFAD as a value-enhancing exercise for the company and the nation.

Time will tell if the trading volumes rise so much that they compensate for these extra costs, but so far, the return is not worth the effort.

Epilogue

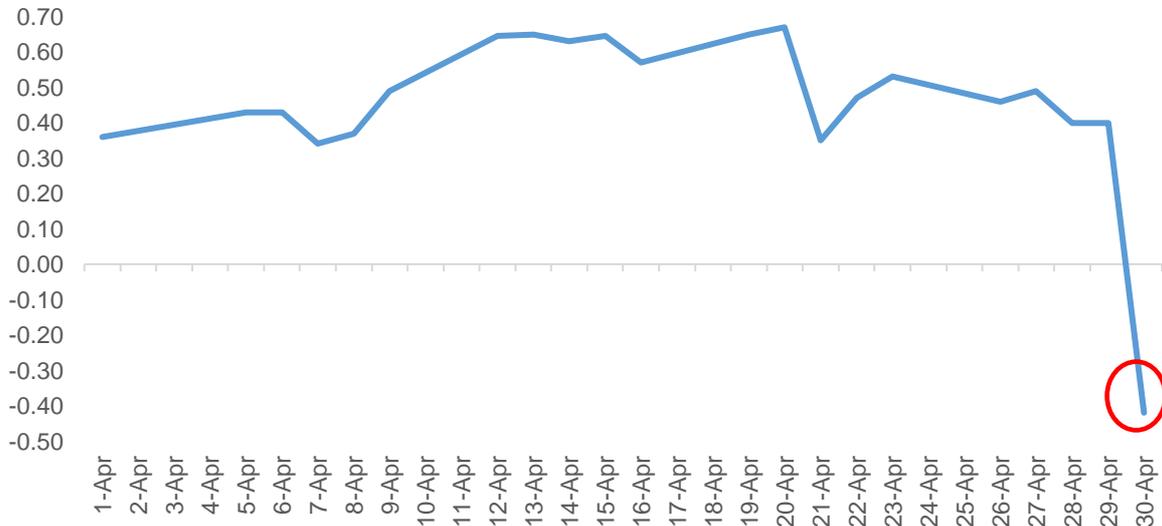
IFAD has gone through the first full monthly cycle and two very important things can be said: first and foremost, the system worked. You can hear the sound of relief. There was daily liquidity even if the volumes at the key marking time of 4.30 p.m. were sometimes painfully small. The other is that the process was orderly up to a point: the expiration surely made some gasp as Murban settled below Dubai!

ADNOC issued its first OSP at 63.35 \$/bbl and as spelled out in its email to its clients: 'IFAD Murban Singapore, Marker 1st line future monthly average during M-2.' In short, the IFAD average during April set the OSP for crude loading in June. Upper Zakum, a key component of the Dubai price setting window system, was set at 40 cents under Murban.

The system is operating and one should expect the same in the upcoming months, regardless of the perhaps incomprehensible gyrations.

On the other side, the bid/offer spreads were very wide throughout the month, signifying underlying low interest to buy or sell the contracts. But more importantly, Murban lost value on the first month of its existence and the expiration was euphemistically 'challenging'. Value is always measured 'versus' other benchmarks and not as flat price behaviour, as this is more the domain of Brent and WTI, which set the daily pace. And Murban fell short of the mark.

Murban–Dubai (\$/bbl)



Source: General Index

The expectations that IFAD would add value to Murban were proven wrong—as they should have been, as nobody will pay you more than a good is worth just because it trades in an exchange. There are exceptional circumstances, such as when a benchmark is squeezed, but no respectable producer, exchange, or publisher wants to be associated with those circumstances.

Murban’s value loss visibly accelerated as the contract neared expiration, and on the last day Murban fell out of bed. Trading in an exchange is very technical, not for the faint of heart, and may resemble a roller coaster ride or even parachute jumping, as it did on the last day.

In graphical detail (see above) Murban lost value relative to Dubai sharply as per data published by General Index. Murban was trading at 40 cents/bbl above Dubai on 29 April and then collapsed to minus 42 cents. As noted earlier, things never go according to plan.



THE SECOND SPLIT: BASRAH MEDIUM AND THE CHALLENGE OF IRAQI CRUDE QUALITY

Ahmed Mehdi

In November 2020, ahead of annual term contract negotiations, Iraq's State Oil Marketing Organization (SOMO) announced it would further split its crude streams (from two into three) by launching a new export grade: Basrah Medium. The launch of Basrah Medium (27.9°API, 3 per cent sulphur) in January 2021 marks the second time Iraq has split its Basrah crude stream, the first being in 2015, with the launch of Basrah Heavy (see table below).

Current specification versus new grades

Assay Spec [Nov 2020]	Old (pre-January 2021)		New (post January 2021)		
	Basrah Light	Basrah Heavy	Basrah Light	Basrah Medium	Basrah Heavy
API (degree)	29.9	24	31.4	27.9	24
Sulphur (%)	2.93	4.05	2.74	3	4.05
Contracted Spec	Basrah Light	Basrah Heavy	Basrah Light	Basrah Medium	Basrah Heavy
API (degree)	34	26	33	29	24

Source: OIES

With Iraq being the only major Middle East producer to have API de-escalators to reflect the volatility of delivered cargoes, Iraq's new crude grade is designed to align the quality in specs between what clients expect to receive (contracted spec) versus what they actually receive (delivered cargoes). From 2015 to 2020 the mismatch in quality between marketed Basrah Light and Heavy and delivered cargoes has proven costly to Iraq.

It has now been over four months since the launch of Basrah Medium. This article explores several issues:

- What were the key drivers behind the launch?
- How has the new grade been priced and has the market welcomed the move?
- In the short term, as OPEC+ cuts ease, which grades are likely to re-enter the market?
- In the longer term, what other strategic factors are likely to bear on Iraqi crude quality?

The problem of Iraqi crude quality

Iraq has always had challenges with crude quality. As far back as 2012, when former Oil Minister, Thamir Ghadhban, commissioned a major Integrated National Energy Strategy (INES) to review Iraq's oil and gas sector, a key recommendation was that 'production increases will require Iraq to formulate a new crude segregation strategy.'

The problem of rising production from heavier oil reservoirs has been a pressing issue for Iraq since the late 2000s, when the average density of Iraqi crude started to increase. This was mainly due to declining production from Zubair reservoir (34–36°API, 1 per cent S) and, since the late 2000s, greater volumes being drawn from the poor quality Mishrif reservoir crude (24–28°API, 4 per cent S). Indeed, Iraq's (now old, pre-2020) Basrah Light contractual spec (34°) was historically based on crude production from the Zubair reservoir (34–36°API, 1 per cent S).

As crude quality deteriorated from 2009 onward (particularly from Rumaila), Iraq's Oil Ministry agreed to introduce—after much negotiation—a new compensation formula with IOCs to account for the mismatch between contracted API volumes and actual API loadings. The introduction in 2010 of a \$0.40 per API degree compensation mechanism replaced what had been a \$0.10 per API mechanism, introduced in 2004.

From 2012 onward, as Iraqi oil production ramped up, additional production from heavier crude streams (particularly West Qurna 2 and Halfaya) was not accompanied by the building of segregated crude storage facilities or settling tanks (to allow for improved blending and crude stability). This led to volatility in the API of Basrah Light—in April 2014, for example, the API fluctuated between 28.1° and 32.4°. This situation was exacerbated by the increased blending of fuel oil into the crude stream.

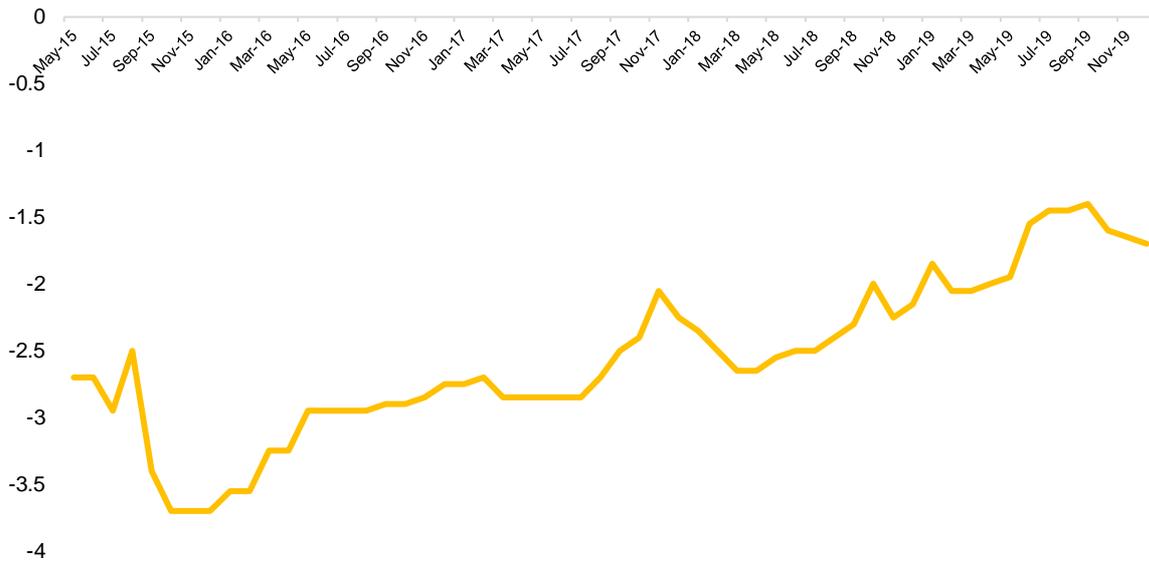
This eventually prompted the creation of a new grade—Basrah Heavy—in 2015, which was produced mainly from West Qurna 2 (WQ-2), Halfaya, Gharraf, and Tuba. The launch of Basrah Heavy initially faced resistance from term-lifters due to the higher-



than-expected OSPs. However, after industry consultation, SOMO adjusted the OSP and pushed the grade onto the market with the support of several IOCs, particularly BP.

Growth in Iraq’s production and exports from 2015 onward was supported by a basic strategy: namely to discount Asia-bound OSPs relative to other grades of similar quality in order to win market share (see graph below). This was a bonanza for IOC equity lifters, who repriced the discounted grade on the market. Indeed, 2015–16 saw regular trades for Basrah Heavy at healthy premiums to the OSP (at times at +3 \$/bbl to the OSP).

Basrah Heavy (Iraq) v Arab Heavy (Saudi)—Asia, \$/bbl



Source: OIES

The launch of Basrah Medium

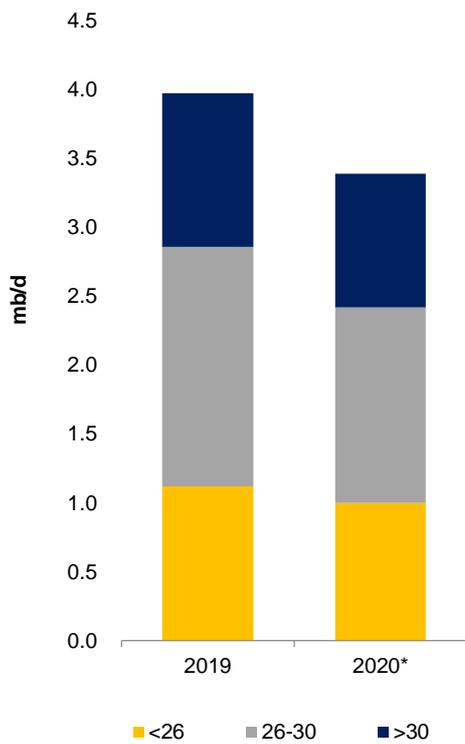
While the introduction of Basrah Heavy in 2015 reflected new crude production (Iraq was one of the largest contributors to global oil supply in 2015–16), the introduction in January 2021 of Basrah Medium was not launched to reflect any new crude supply, but rather to address the following:

- **Grade stability:** Between 2015 and 2020, Basrah Light was marketed as 34°API and Basrah Heavy as 26°API, but deliveries always fell short of these specs.
- **API compensation:** The mismatch between contracted and delivered cargoes had serious cost implications for Iraq. Basrah Light buyers have generally been compensated \$0.40 for each whole API degree below contracted specs (and 0.60 \$/bbl for every °API below Basrah Heavy’s contracted 26°API). With an average API of 29 degrees for Basrah Light (BL) deliveries in 2020, SOMO, in practice, had to compensate buyers by roughly 2 \$/bbl. With average sales of 2.2 mb/d of Basrah Light (BL) in 2020, this translated to a total annual cost of \$1.6 billion—a major cost component in Iraq’s oil sales balance sheet, particularly during the 2020 oil market turmoil when Iraq’s economy was under significant economic pressure. Not only was the 0.40 \$/bbl per API degree overly generous, leading to high payouts, but it also made Basrah an attractive set of grades to trade in the spot market. As a result, a healthy and liquid secondary market for Basrah Light took root, with attempts by SOMO to restrict resales proving futile.
- **Infrastructural upgrades:** From 2015 to 2020, a number of key infrastructural upgrades have taken place in Iraq’s midstream and export infrastructure, helping pave the way for an additional grade launch. The completion of the Tuba–Fao pipeline (built by Lukoil) allows heavy crude stored at Tuba to be transported directly to Fao. Likewise, the completion of the PS1–Fao pipeline (in 2016) helps ease midstream bottlenecks and allows a dedicated crude grade to be stored at the storage site (currently with 10 tanks, each with 82,000 cubic metres capacity). The planned completion of the Sealine-3 subsea pipeline will also add an additional 700 kb/d export capacity (connecting the pipeline to SPM-4). This is expected to be completed by end-2021/early 2022.

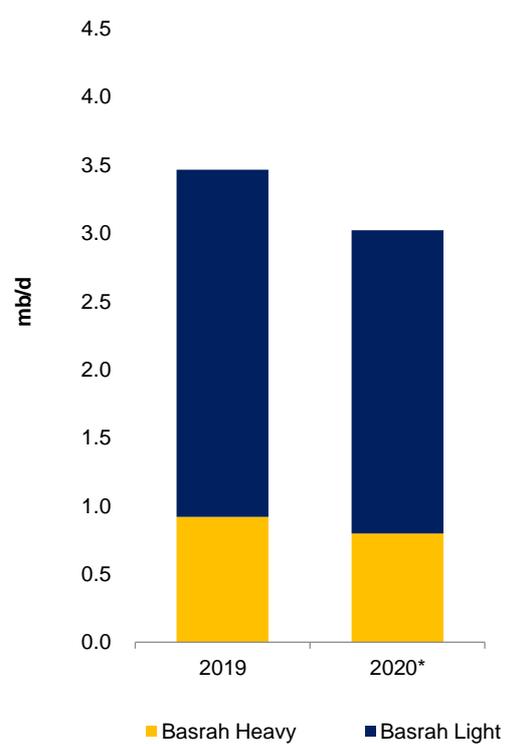


- **Better reflect upstream realities:** Throughout 2019–20, it was becoming increasingly clear that Iraq’s upstream production was already reflecting three distinct groups of APIs but marketing just two (Basrah Heavy and Light).
- **Inappropriate level of gravity escalator:** Critically, SOMO’s use of the 0.40 \$/bbl per °API (gravity escalator) was out-of-sync when compared to both spot market valuations and light–heavy differentials.

Southern Iraq—production by API



Southern Iraq—exports by grade



*Jan–Oct 2020

Source: OIES, FGE

Basrah Medium pricing

Prior to the launch of the new grade, SOMO released a list of alternative OSPs (for H2 2020) to help clients understand how OSPs would be set, taking into account de-escalator and spec alignment. From a pricing perspective, it is clear that SOMO sought to achieve the following objectives with the spec shift:

- Price Basrah Heavy OSP in line with the adjusted Basrah Heavy price after applying \$0.60/°API compensation for a 2°API deviation from the spec
- Price Basrah Medium in line with adjusted Basrah Light prices after applying \$0.40/°API compensation for 5°API deviation; and
- Price New Basrah Light in line with Arab Light, assuming deliveries of the new Basrah Light would have an API close to its contracted 33°. The new pricing for Basrah Light would also capture the losses made in compensation payments.

The launch of Basrah Medium has also meant a reshuffle in the grades Iraq will compete with in the market (see table below).

So far, Basrah Medium exports have averaged ~900 kb/d, but the market should expect to see greater availability of both Basrah Medium and Heavy later this year, as OPEC+ cuts ease for Iraq. Critically, Iraq’s OPEC+ cuts have come from both state-operated fields and IOC-operated fields. Decision-making on which fields to cut from IOC-operated fields is based on both cost and quality. As OPEC+ cuts ease, it is expected that the first fields to be released from cuts will be those with lowest-cost and highest-quality (predominant contributors to Basrah Medium volume).

Iraqi crude grades and competing grades

Crude Grade	API	Sulphur (%)
Upper Zakum	33.9	1.8
Oman	33.5	1.4
Basrah Light	33.0	2.7
Arab Light	32.9	2.0
Arab Medium	30.7	2.5
Kuwait Export	30.5	2.5
Al Shaheen	29.0	2.3
Basrah Medium	29.0	3.0
Arab Heavy	26.9	3.1
Basrah Heavy	24.0	4.1

Source: OIES

With greater availability expected later this year, it is worth asking: has the grade been popular so far? Several points are worth noting:

- **Tighter API range:** data obtained from port agents show the average API of delivered cargos for each grade being fairly close to contracted API—helping reduce compensation payments owed by Iraq to lifters.
- **Pricing:** since the grade's launch, Basrah Medium has been priced at a significant discount to other medium-heavy grades in the Middle East.

SOMO's competitive pricing for Basrah Medium has supported spot valuations for the grade in the physical market. Beyond competitive pricing, another reason for the grade's popularity in recent trading cycles include the impact of Saudi's 1 mb/d voluntary cut. Other potential explanations for Basrah Medium's discount can be explained by a higher-than-acceptable salt quality of the grade, which suggest that while API ranges have improved, quality issues remain a concern.

While Basrah Medium has been discounted heavily, the opposite appears to be the case for the new Basrah Light. Since January 2021, Iraq's new Basrah Light grade has been trading in steeply negative territory, with a number of trades clearing at negative 0.70–1 \$/bbl. This suggests that SOMO is (over)pricing Basrah Light based on its paper value. While this means Iraq will make more money from Basrah Light sales, feedback from equity lifters surveyed by the author has been negative on pricing since January 2021.

Final observations

We can make the following observations on the launch of Basrah Medium and other strategic implications for Iraq going forward:

- On a positive note, Iraq will now pay less compensation to lifters as there is now greater alignment between contracted and delivered specs.
- Despite this, Iraq's ongoing use of an overpriced de-escalator is not justified by market realities.
- With Iraq having now captured more of the tradable value of its crude (via lower compensation payouts), SOMO will have a more delicate balancing act going forward, specifically ensuring that equity lifters remain satisfied with their grade allocations and margins. For years, equity lifters were satisfied with Iraqi pricing, due to the overly generous compensation. With that having diminished, Iraq will need to ensure the OSP flat price remains attractive, as this bears consequences for liftings and, ultimately, investment rates in Iraq's upstream (which already suffer from an onerous fiscal regime). IOC margins in Iraq are already tight—with Exxon's departure being the latest development—and equity cargoes have been a central pillar of Iraq's attractiveness.



- Iraq will also need to increase infrastructural flexibility. The country’s production profile is transitioning to a more complex mix of heavier Mishrif crude (increasing Basrah Heavy supply) and lighter Yamama (helping Iraq increase its share of light crude exports). Quality concerns will continue to dominate refiner thinking until operators address issues such as increased water handling (water-cut) and other factors impacting quality (for example metals and salt content). Rumaila Operating Organization (ROO), for example, has already started addressing these issues by installing dehydrators, desalters, and new tanks, to help address quality concerns. While this is a positive step, state investment in storage upgrades, pipeline expansions, and the use of technologies (for example SCADA systems) to monitor crude quality will be the necessary next step.

In this light, Iraq’s latest crude export launch may represent more a levelling of the playing field in capturing value, rather than a quick fix to its ongoing crude quality challenge. While this is a welcome development, Iraq has to achieve a fine balance between avoiding under pricing its Basrah Medium and over pricing its Basrah Light.

CHINA’S SHANGHAI INE CRUDE FUTURES: HAPPY ACCIDENT VERSUS OVERDESIGN

Tom Reed

The experience of China’s Shanghai INE exchange offers cautionary examples of the challenges facing new sour crude futures initiatives. The physically settled Chinese futures contract—launched to considerable fanfare on 26 March 2018—has generated huge amounts of daily trade by financial investors but gained little traction as a means of supplying refiners with crude.

INE crude futures ‘total trading volume reached 113.2 million lots over the past three years, valued at over 44 trillion yuan (\$6.7 trillion)’, a homily from the *China Daily* newspaper noted in April. But that 113 billion barrels of financial trade has channelled only around 30 million barrels of crude to refiners since INE ex-tank spot trade got underway in July 2020. Over the same period, some 533 million barrels of crude has been delivered to refiners through a spot market centred around Shandong province in the north of the country.

The Shanghai INE exchange was not conceived as a primarily financial instrument, although it is intended to offer a means of hedging in yuan. Its stated mission is to ‘facilitate the optimal allocation of energy resources’ in China and, more broadly, offer a new East of Suez crude benchmark. But it has also had, since its inception, an implicit political mandate aimed at allowing China—the world’s largest crude importer—to become ‘the price maker instead of a price taker’.

Beijing’s desire, that a national crude marker should align with the feedstock preferences of state-owned refiners, was a key factor in the decision by INE architects to allow contracts held to expiry to be settled through the physical delivery of Middle East Gulf grades—Dubai, Upper Zakum, Oman, Qatar Marine, 28°API Basrah Light and, from June, Murban. The region supplies over a third of China’s crude imports and the majority of its state-owned refineries have been built to run feedstock with similar qualities to Saudi Arabian Medium and Light grades.

It is highly debatable that, given its outsize demand requirements, China has been a passive taker of benchmark prices formed close to points of loading in the Middle East Gulf or North West Europe for many years. Chinese state-owned firms, which boast large and sophisticated trading and shipping operations, generally prefer to buy crude on an FOB, not a delivered, basis. And the competing commercial interests of Chinese firms have often buffeted overseas benchmarks such as the Platts Dubai marker, to the frustration of other market participants.

Had it not been anathema to Beijing’s central planners, the natural market for a delivered China crude futures contract should, more realistically, have been the country’s independent refiners. These, with a combined crude unit capacity of some 3.6 mb/d, prefer an all-in cost of crude and almost invariably buy on a delivered ex-ship (DES) basis. But the latter also favour sweet grades over sour INE-accepted ones.

Disaster mover

And, had it not been for COVID-19, the Shanghai INE market might have remained a financial-only instrument. But when global crude prices collapsed in April 2020, INE prices did not, because the Chinese government set a floor price under gasoline and diesel that ensured continued robust margins for domestic refiners. Net of freight, the INE’s Month 3 contract rose to a 13 \$/bbl premium above the equivalent DME Oman price and sucked in vast amounts of crude throughout 2020’s second quarter.

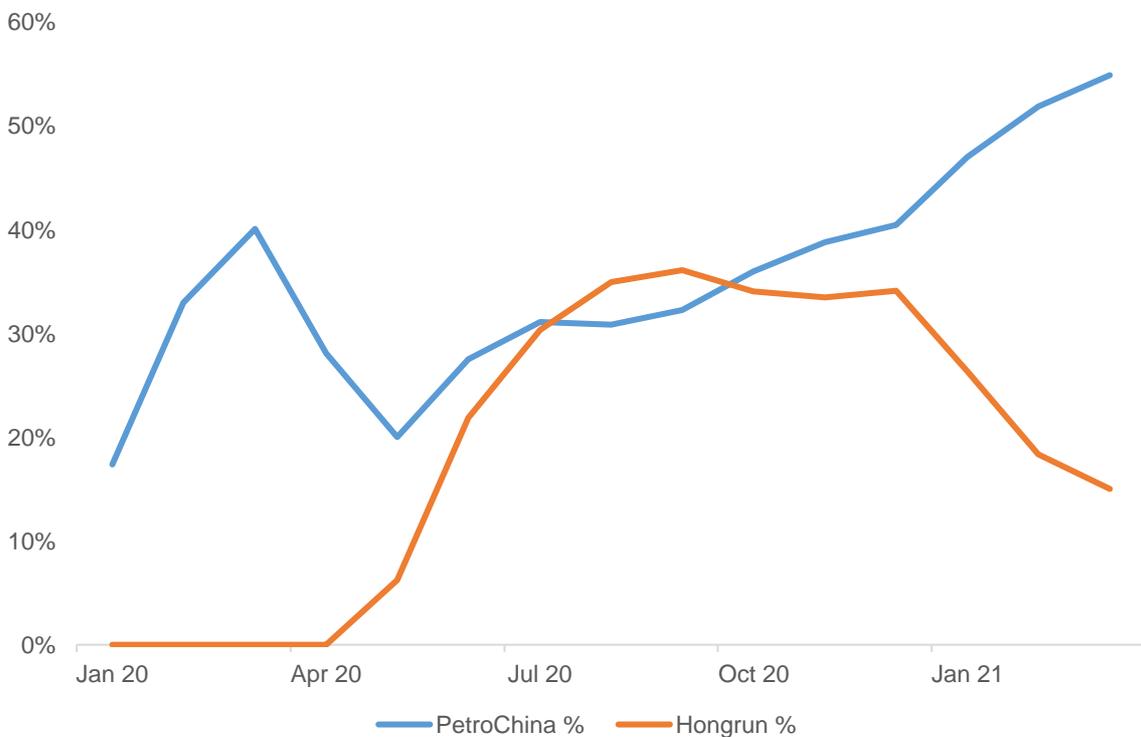


The exchange’s delivery mechanism still lacked credibility, however, because state-owned firms controlled almost all the available storage sites. Many trading companies holding short positions to expiry feared that their commercial interests might clash with those of the storage sites’ state-owned oil company operators, and that they could encounter difficulties in making delivery.

The INE—to its credit—moved very rapidly to secure additional independent tank space in Shandong province from a Shandong firm called Hongrun, by allowing it to double storage rents. Hongrun is China’s largest private sector storage operator, whose 80 million barrel tank farm serves primarily independent refiners around Dongying city. And so, by accident rather than design, the INE became a viable option for independent refiners to procure crude.

Crude rapidly piled up at Hongrun’s giant Weifang tank farm between May and September 2020—by late July stocks were rising at over 400 kb/d. Then, between September last year and the end of March 2021, some 12.6 million barrels were withdrawn by refiners. By contrast, stocks at tanks operated by PetroChina, barely moved. The oil giant’s tanks, at the end of March, accounted for 55 per cent of all crude held under INE auspices (see graph below).

Shanghai INE stocks by storage tank operator (%)



Source: Shanghai INE

Buying crude from INE tanks remains a fiddly business. Oil firms wanting to take delivery through INE can hold long positions to expiry—a common route for trading companies—when the exchange issues them with a warrant certifying ownership of the crude and its location. Warrants can be held indefinitely but are cancelled when the holder declares its intention to move the crude. The exchange tries to match sellers to buyers, but the latter have limited control over the crude grade or location of their purchases.

The latter complain that the exchange may award a refiner in Liaoning warrants for crude in Hainan, thousands of kilometres away, and that moving crude from INE tanks through pipelines controlled by state-owned firms or by truck to their own refineries is costly. But they also say that undertaking the process of purchasing sufficient 1,000 barrel INE warrants to put together a cargo themselves is complex—potentially requiring negotiations with hundreds of warrant holders. The emergence of domestic trading companies specializing in aggregating INE warrants has, partly, remedied this problem. These firms—such as state-owned Si Bang and Xiamen Guomao—typically buy crude from warrant holders that lack the capacity to take physical delivery, and aggregate cargoes for refiners.



Spot the difference

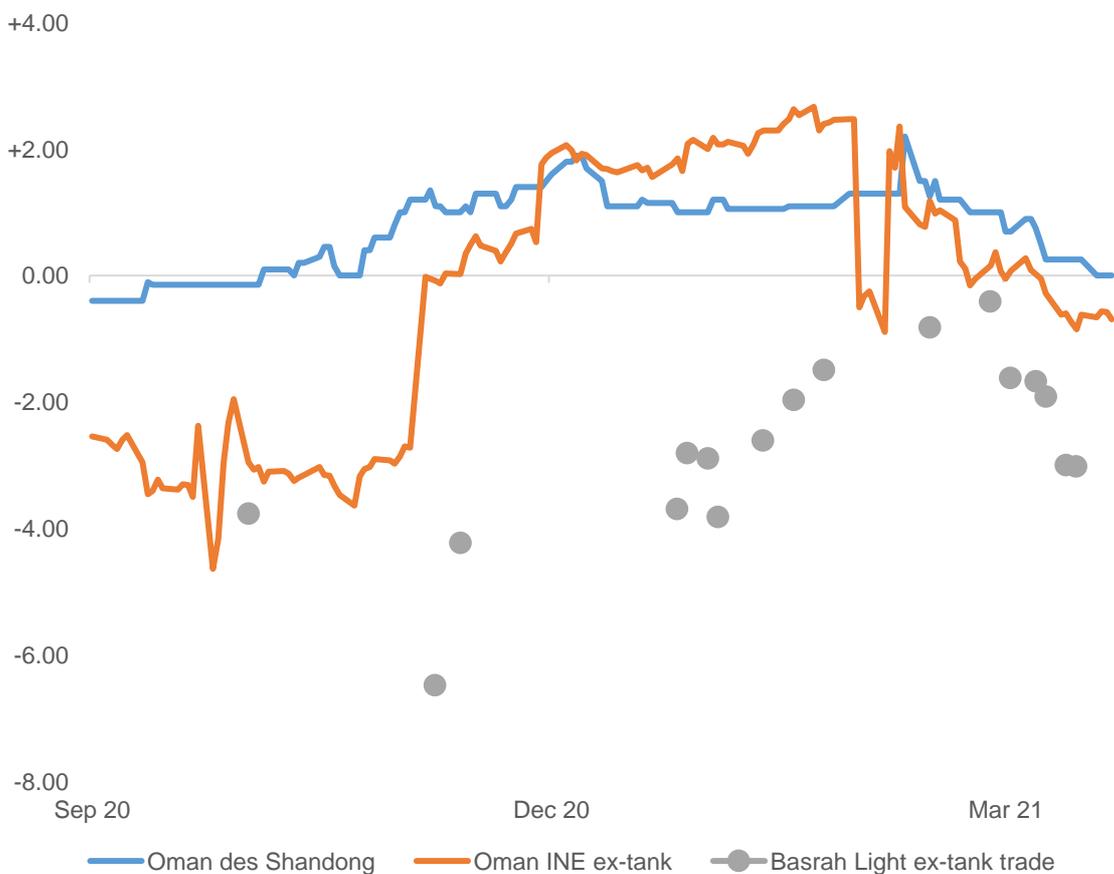
Because INE tanks are ‘bonded’, independent refiners must clear purchases through customs using the government’s quota system to manage imports. China’s commerce ministry issues a finite supply of these quotas in semi-annual batches. INE ex-tank sales tend to be very prompt. This creates a risk that, by the time the INE ex-tank trade cycle starts, many refiners have already used up their quota supply in buying long-haul imports several months in advance.

Even so, it is independent refiners in Shandong and Hebei provinces that have contributed the clearest price signal for INE ex-tank spot trade, accounting for two-thirds of all ex-tank INE deals since July, or around 20 million barrels. The state-owned oil giants’ system refineries that the exchange was designed to serve have bought just 4 million barrels from INE tanks.

INE spot deals are typically priced as discounts to front-month ICE Brent futures or—less commonly—as premiums to the exchange’s own contracts, compensating for the discount of INE to Brent futures. It is doubtful that government officials are delighted to see an overseas benchmark used to price INE ex-tank sales, but ICE Brent futures emerged as the market’s preferred reference for delivered sales to China soon after the semi-deregulation of crude imports in 2016.

Iraq’s 28°API Basrah Light accounted for the bulk of deliveries through the futures exchange and is the most commonly-lifted INE grade. Some 11.7 million barrels of Basrah Light has been sold from INE tanks since July, followed by Oman (8.6 million barrels) and Upper Zakum (8 million barrels). Detailed data for ex-tank trades to date, covering around half of all deals gathered by Argus, show 90 per cent priced at differentials to ICE Brent and 10 per cent against INE contracts. These spot deals are usually done against front month ICE Brent futures on the date of the deal, but may be priced against the same contract on the date that the buyer cancels the warrant. INE ex-tank parcel sizes (400,000 barrels on average) are smaller than the 1 million barrel trades common to the DES market, which is a VLCC market. This, again, militates in favour of independent refiners, who often face cash flow constraints and may struggle to finance large cargoes.

INE ex-tank vs DES Shandong (\$/bbl)



Source: Argus



Ex-tank barrels trade on average 30 days ahead of delivery compared with 60–90 days forward for DES trades. This makes the ex-tank market a convenient option for capitalizing on short-run price changes in prompt-trading product markets. The chart above shows ex-tank deals for Basrah Light and prices for Oman normalized to the prevailing ICE Brent contract used in DES spot market trades. The deep discounts for Basrah Light appear to reflect quality rather than timing issues, as well as the prevalence of Basrah Light in INE tanks. Oman is a popular grade in Shandong, but relatively little was delivered through the INE, and it commands higher prices. Sweeter grades traded on an ex-tank basis in Shandong, but outside the INE system, commanding yet higher premiums to futures. Independent refiners usually blend feedstock sulphur content down to below 1 per cent in order to produce road fuel that meets Chinese tailpipe emission rules.

And, due to these quality preferences, the INE spot market remains a market of last resort for local refiners. Spot crude trade on Shandong's ex-tank—also known as DDU (delivered duty unpaid)—market accelerated dramatically in March as inventory drawdowns supplanted imports to meet refiner feedstock requirements, but the preferred grades remained, overwhelmingly, sweet—ESPO Blend, Ceiba from Equatorial Guinea, Nigerian Usan, or Brazilian Tupi—dwarfing INE sour volumes.

This has been a fundamental challenge facing INE futures: it is more difficult to design a sour crude contract because the wider variety of refinery upgrading configurations needed to process medium/heavy sour crudes leads to very different netback values compared with more straightforward light sweet crude economics.

Slow on the draw

This reluctance of Chinese refiners to use the INE as a means of procuring physical barrels means stocks are only slowly draining from the system. Stock levels rose at 200 kb/d in the first half of 2020 and then shrank, but at half that rate, in July–December. The overhang has been a major contributing factor to INE contracts remaining in contango while global benchmark contracts returned to a backwardation structure.

The negative roll yield on INE futures penalizes financial investors but benefits holders of physical barrels in storage. And firms with a commanding number of physical market warrants can further make money by selling INE futures—confident that the inventory surplus will continue to depress values relative to ICE Brent—and buying the latter. This allows them, later, to buy back INE futures and sell pricier Brent.

Storage operators also benefited handsomely from the exceptionally high tank fees the INE implemented to draw tank capacity into the market last year. In a move intended to foster inventory churn, the INE slashed its storage fees from 1 March 2021. In other markets, this might encourage companies with physical oil to keep it in tank. But the INE exchange hopes that, by eroding storage profits, more oil will be released to the market because INE storage operators and physical warrant holders, often, share a parent entity.

The arrival of a flood of Iranian crude in 2021 has complicated this plan. Shandong refiners, hitherto the main buyers at Weifang, would now rather buy heavily discounted sanctioned barrels than comparable quality INE crude, creating another impediment to stockdraws. Basrah Light differentials to ICE Brent have been forced down to a level that allows the grade to compete with Iranian Light on the prompt market.

China's crude surplus is not only evident in INE tanks. Nationally, stock levels were close to all-time highs in March and oil firms focused on de-stocking, rather than securing fresh imports. Even when China's de-stocking cycle has run its course, there are no guarantees that INE prices will recover to a level that makes fresh deliveries economical. The weakening of the US dollar relative to the yuan counts against it, helping close off the arbitrage to deliver fresh barrels into the INE system. The US currency has fallen by over 6 per cent since July last year, forcing the yuan-denominated INE contract to adjust lower because traders are buying in dollars and selling in yuan.

Further questions hang over the nature of the crude that would be delivered through the futures exchange. Iraq no longer produces the minimum 28°API Basrah Light that, as the lowest value grade in the INE basket, accounted for the bulk of last year's deliveries. The exchange has not clarified which, if any, grade will replace it although it will accept Murban from 1 June. As a light grade, this would be far less palatable to the distillate-focused refiners of Shandong. And, what is more, the 70 cents/bbl premium that the INE has promised sellers supplying Murban at expiry is likely to make it, in many instances—and potentially even if the INE adds new 29° Basrah Medium—the most lucrative option for trading firms when the INE settlement price plus Murban premium is less than the cost of Murban plus freight. Even at Chinese state-owned firms, there is a recognition that this latest development appears likely to benefit producers of Middle Eastern crude rather than domestic refiners.



FUJAIRAH'S RISE TO PROMINENCE

Captain Salem Al Afkham Al Hamoudi

The Port of Fujairah's transformation from a sleepy fishing harbour to the most prominent port along the East of Suez-to-Asia energy corridor, together with the emergence of the Emirate of Fujairah as the Middle East's premier hub location for oil trading, storage, and bunkering, and as a centre for price benchmarking, in such a short space of time, is unprecedented.

It was once said 'out of adversity comes opportunity' a statement that very much embodies the Fujairah success story.

The Iran–Iraq war in the 1980s had a major impact on the global shipping industry and global supply chains. Major restrictions were imposed on vessels transiting the Strait of Hormuz, resulting in large convoys of vessels being formed in the safe waters of Fujairah in preparation for safe passage through the Strait. Located 70 nautical miles from the Strait and in close proximity to major international shipping lanes, Fujairah soon became established as a safe haven for vessels transiting the Strait. The government of Fujairah, under the patronage and vision of His Highness Sheikh Hamad bin Mohammed Al Sharqi, Member of the UAE Supreme Council, and Ruler of Fujairah, quickly recognized the strategic importance of Fujairah's location and embarked on a journey to develop the Port of Fujairah into one of the world's major bunkering hubs.

Today, Fujairah is one of the world's top three largest bunkering hubs and is well positioned to support the market with compliant and compatible Marine fuels. The local Vitol refinery and Uniper's topping units, located in the Fujairah Oil Industry Zone (FOIZ), are set to produce large volumes of Low Sulphur Fuel Oil (LSFO) either as straight run or as a blending component. The surrounding storage terminals are equipped with the necessary blending infrastructure, allowing traders to blend competitive products. The Port's flexible and sophisticated infrastructure ensures clear segregation between the various products flows, as well as sufficient berth availability for bunker barges.

The emergence of the Port of Fujairah as a major bunkering hub attracted the attentions of internationally recognized storage providers such as Royal van Ommeren (now Vopak Horizon Fujairah Ltd, VHFL). In the late 1990s Royal van Ommeren constructed the first 'Third Party Storage Terminal' in Fujairah, consisting of 400,000 cubic metres of storage and two jetties (VHFL capacity is currently 2.6 million cubic metres). The success of VHFL led to NOCs, IOCs, International Storage Providers, and major oil traders seeking opportunities to develop a presence in Fujairah.

Hand in hand with the growth in demand, the government recognized the importance of establishing a designated petroleum zone (FOIZ) to regulate all aspects of the Fujairah oil and gas industry, providing governance, support, and infrastructure opportunities for investors. Currently FOIZ occupies an area of approximately 10 square kilometres, and a project to reclaim a further 3 square kilometres is ongoing.

A clear example is Aramco Trading Company (ATC), which began operating out of Fujairah in March 2013 by leasing refined storage capacity. This gave ATC more flexibility to trade products, with a focus on exporting barrels to Asia and securing fuels for Saudi Arabia. Successful growth led to further commitment and in 2019 ATC opened an office in Fujairah, their second after Singapore.

To meet this growing demand the Fujairah government proactively embarked on a phased programme of upgrading the port, providing state-of-the-art infrastructure, sophisticated in design but capable of providing terminals with the ultimate in flexibility. Major land reclamation projects were also implemented to increase the footprint of both the Fujairah Oil Industry Zone and the port.

In 2006 the Port of Fujairah established and commissioned the Fujairah Oil Tanker Terminals, consisting of three main berths dedicated purely for oil tankers, and capable of accommodating vessels ranging from 3,000 to over 100,00 deadweight tonnage (dwt). Each berth can accept either one large vessel or two smaller vessels with length overall (LOA) not exceeding 130 metres. This was followed by a further four oil tanker berths being constructed and commissioned in 2010, each capable of accommodating vessels ranging from 3,000 to over 200,00 dwt and a one-of-a-kind Matrix Manifold (MM). MM1, occupying approximately 24,000 square metres of real estate, enables any of the terminals within the Fujairah oil zone to be connected to any of the berths within the port.

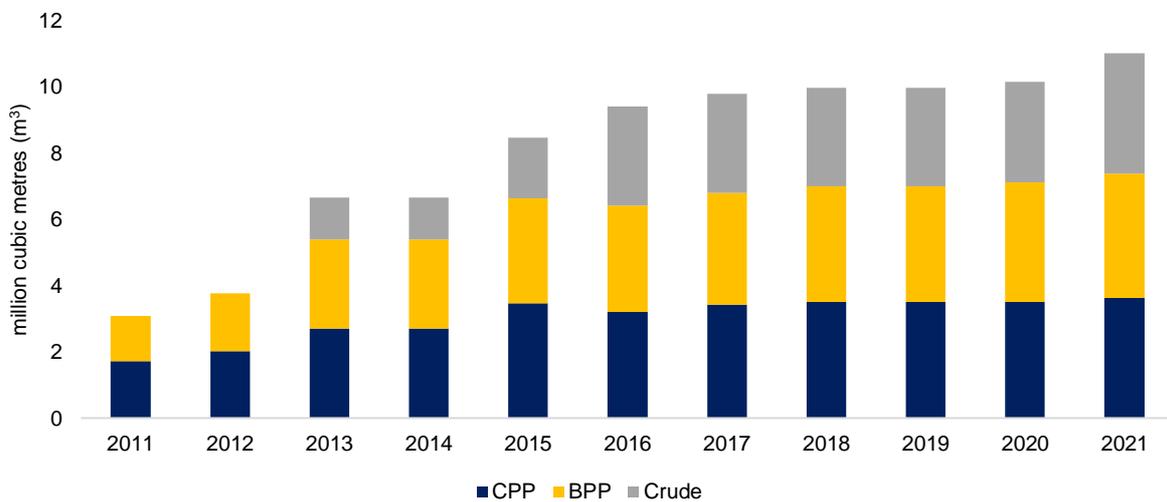


The concept of the Matrix Manifold is unique to Fujairah. It enables multiple terminals to load or discharge product to and from the same vessel simultaneously, as well as providing a conduit between the terminals, allowing them to transfer and trade products between each other without the need to charter a vessel. These features provide terminals, their customers, and traders with a significant commercial advantage over their competitors, and unparalleled economies of scale.

Fujairah’s prominence as a leading bunkering and logistics hub boosted the construction of new storage facilities, which expanded exponentially, increasing storage capacity from 3.2 million cubic metres in 2011 to over 9 million cubic metres in 2016 (see chart below). In preparation for the additional capacity, the port quickly set about reclaiming more 680,000 square metres of land to construct two additional oil tanker berths, two dedicated bunker barge berths, a second MM (with interconnectivity lines to MM1), and the region’s only dedicated VLCC Berth.

The development of new storage terminals allowed Fujairah’s reputation to grow beyond bunkering, and it became the region’s largest oil storage, blending, and trading hub for refined products, especially for gasoline and fuel oil products. Current storage capacity is over 11 million cubic metres and new expansion projects have been announced by Ecomar and BPGIC, adding close to 2.5 million cubic metres of additional storage capacity by 2024.

Fujairah storage capacity (million cubic metres)



CPP=Clean Petroleum products; BPP=Black Petroleum Products
 Source: Fujairah Oil Industry Zone.

Fujairah’s refining capacity currently stands at 185 kb/d; however, as depicted in the chart below, projects have either commenced, or are in the engineering phase, to increase Fujairah’s refining capacity to 430 kb/d by 2026.

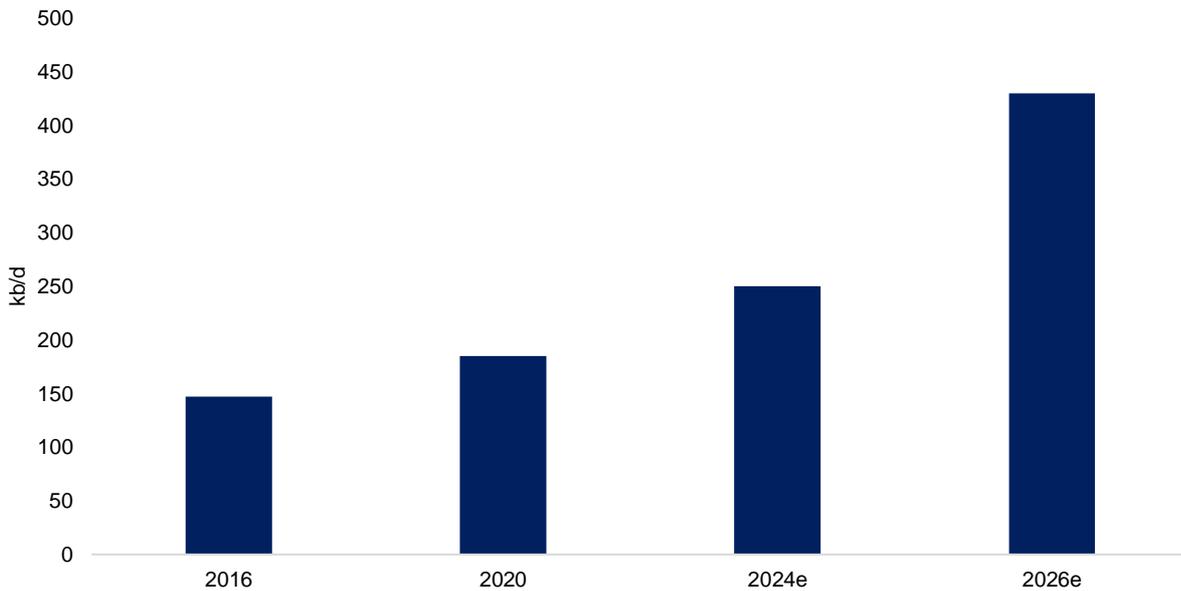
The success of Fujairah’s development is further strengthened by its strategic location outside the Strait, as well by the wide ranges of marine services offered at the Fujairah Offshore Anchorage Area (FOAA). It is considered as a one-stop-shop for the maritime industry, providing comprehensive services such as: bunkering, ship repairs, chandlery services, vessel inspections, crew changes, a complete medical clinic dedicated for seafarers, and one of the largest maritime service hubs in the world, with more than 13,100 vessel calls in 2020.

Further evidence of the importance of Fujairah as a global logistical hub is provided by ADNOC decision to invest in a 406 kilometre, 1.8 mb/d pipeline connection from its Habshan oil fields to its dedicated 7.8 million barrel crude storage facility in Fujairah. This project was completed in 2012, with ADNOC loading significant volumes of Murban crude via three dedicated VLCC Single Point Mooring Buoys (SPMs).

ADNOC is continuing to grow its footprint in Fujairah, constructing a 42 million barrel underground storage capacity costing an estimated \$1.21 billion. The caverns are designed to store three different types of crude oil, enabling it to proactively respond to market needs and commercial opportunities. Pipeline connectivity between ADNOC’s dedicated storage facility, the caverns, and the Port of Fujairah provides ADNOC with business continuity / contingency and further logistical and commercial flexibility.



Fujairah refining capacity (kb/d)



Source: Fujairah Oil Industry Zone

On 29 March 2021 ADNOC launched its new Murban crude oil futures contract at the ICE Futures Abu Dhabi exchange, providing transparent pricing and a forward curve to participants. Buyers will take delivery at Fujairah on a free on board (FOB) basis. This is the latest step in ADNOC’s ongoing transformation into a more market and customer centric organization.

Fujairah is a key partner for ADNOC’s growing ambitions in global energy trading, which is supported by the incorporation of its two trading units:

- ADNOC Trading (AT), which focuses on the trading of crude oil,
- ADNOC Global Trading (AGT) that will focus on the trading of refined products.

The entities started trading in September and December 2020 and AGT has already taken a storage position in Fujairah. At the Fujcon 2021 conference, ADNOC Executive Vice President for Sales and Marketing, Philippe Khoury, said that Fujairah is ‘for us a key enabler of our international and domestic strategy’.

With the launch of Murban futures and S&P Global Platts’ existing FOB Fujairah refined product assessments, the market will, for the first time, have product and crude values on a Fujairah basis, allowing for proper, side-by-side analysis.

In partnership with S&P Global Platts, FOIZ publishes weekly oil inventory numbers utilizing the first application of the highly secure blockchain technology in the oil and gas industry. This provides FOIZ and the terminal operators with transparency through secure access to information, ease of use, and a full audit trail to collate weekly inventory oil products storage data, and creates market transparency enabling traders and investors to see opportunities and risk more clearly.

There is a strong demand in the global markets for a price hub in the Middle East to better manage the flow of swing barrels moving from the region to demand centres in Europe and Asia—as such, the objective of publishing the weekly inventory data is to establish Fujairah as the regional pricing centre next to Singapore and Rotterdam.

This is further supported by the recent launch of published monthly bunker sales volumes, which are freely available to the market on the 20th of each month. This will bolster the strong organic growth towards becoming a comprehensive global energy hub.

Fujairah, the UAE’s only Emirate on the Indian Ocean, is accelerating its strides towards becoming a critical node on the international energy markets map. This is most evident in the continued infrastructure investment by FOIZ and the Port of Fujairah, and the expansion of its capacity to handle and process petroleum and bunker products, which now amounts to over 120 million tons per year of crude oil and refined products.



Going forward, the government of Fujairah’s main focus will be on:

- improving governance to the banking and information sectors,
- ensuring sufficient land and infrastructure will be available to capitalize on the launch of Murban futures,
- becoming a major location for crude storage and trading—perceived as being the next evolution of Fujairah,

while maintaining the highest safety standards and most efficient and flexible service levels, including very low ship turnaround times.

Fujairah’s journey from a small fishing harbour, into the Middle East’s largest oil trading hub, in just over 30 years has been extraordinary. However, the Fujairah government is not resting on its laurels and is proactively working towards the next evolution of Fujairah in crude oil storage and trading, strongly supported by ADNOC’s commitment and the launch of the Abu Dhabi ICE Futures contracts. Fujairah is also striving to further diversify its portfolio by developing LPG and LNG infrastructure, as well as playing a key role in the renewable fuels landscape, to eventually emerge as a true global energy hub.

FUTURE OF THE SINGAPORE PRODUCTS NETBACK: MIDDLE EAST PRODUCT PRICING

Ahmed Mehdi and Iman Nasser

Since 2010, the Middle East has added nearly 2.5 mb/d of refining capacity, transforming the region into a key net product exporter. In conjunction, Middle East National Oil Companies (NOCs) such as Saudi Aramco and ADNOC are building up product trading arms to optimize flows and capitalize on the region’s growing role as a product trading hub. With COVID-19 having accelerated the rationalization of European refining capacity and the Middle East accounting for the bulk of new capacity out to 2030, growing attention is being paid to the pricing of Middle East refined products. Already, the market has seen the roll-out of new flat price assessments (alongside netback values) to reflect the region’s changing product balances, trade flows, and market activity. COVID-19 also gave the market a snapshot *in extremis* of how freight volatility can distort product values, further highlighting the importance of pricing optionality in products.

Against this background, this article examines the following issues:

- The growing importance of flat price versus netback assessments.
- Fujairah’s role in expanding the pricing ecosystem used for Middle East product pricing.
- And finally, what trade-offs lie ahead for Gulf refiners as the strategic influence of the Middle East in global product markets grows.

The Singapore netback model

Historically, Gulf refiners have used the Singapore netback model to price their product exports (gasoline, naphtha, jet, diesel, and fuel oil). Calculated as freight netbacks that derive their value from Singapore product prices, Means of Platts Arab Gulf (MOPAG) price assessments remain at the heart of the Middle East product pricing complex.

$$MOPAG \text{ Netback} = \text{Means of Platts Singapore (MOPS)} - \text{Freight rate between Singapore and the Gulf.}$$

This is due to a number of reasons:

- **Refining and Storage:** Singapore’s historical role as a product trading hub has been rooted in its refining and storage industry. Singapore’s refining capacity stands at around 1.5 mb/d (although Shell has recently announced that it will halve crude processing capacity at its Pulau Bukom Refinery, shutting down 200 kb/d CDU capacity). Singapore has nearly 32 million barrels (mb) of clean products tank storage with another 35 mb of fuel oil tannage. Counting storages in Malaysia and Indonesia as part of the Singapore Straits, the Greater Singapore area, with roughly 140 mb of storage capacity, is home to the biggest independent oil storage industry. Multiple storage terminals acting as loading points in this area create the necessary infrastructural flexibility for accurate price signals.
- **Liquidity and transparency:** a key prerequisite for any benchmark, Singapore attracts multiple trading players, avoiding market concentration by a sizeable few. Singapore product trades are well-proven with multiple bids,



offers, and trades. The lack of spot liquidity in the Gulf also made Singapore the least bad option, particularly given the weakness of Gulf price discovery.

- **Trade flows:** the freight netbacks at the heart of MOPAG assessments have reflected the natural flow of barrels.

Over the past several years, however, pressure has grown by Gulf refiners to call for flat price assessments to capture a number of strategic trends. These include:

- The Middle East’s growing share in the volume of global product trade and exports.
- The expansion of Middle East refining and storage capacity.
- Local market dynamics in the Middle East: these can include seasonal consumption trends which impact market differentials, refinery maintenance, and arbitrage flows.

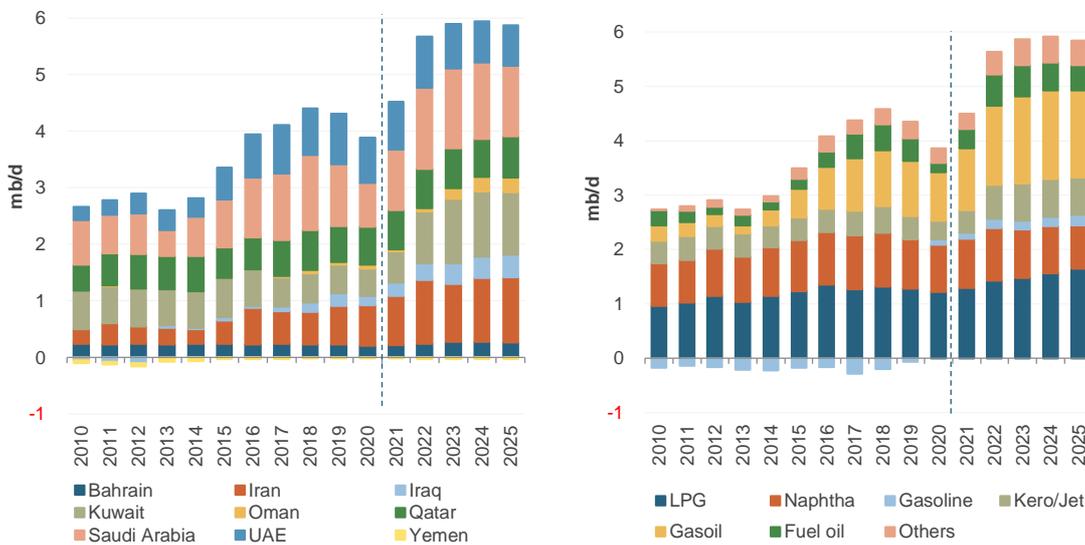
The rise of the Middle East as a product exporter...

The region’s net products exports (including LPG) have been on the rise since 2014 on the back of stagnant demand and increasing supply (from both refinery and non-refinery sources), and exceeded 4.3 mb/d in 2018 before the trend came to a temporary halt in 2019–2020.

Further refinery capacity growth will bring another surge in the balance (in other words, higher net exports) to nearly 5.9 mb/d by 2025. The majority of the increase will be in middle distillates (~850 kb/d). LPG exports will also grow from 1.3 mb/d currently to 1.7 mb/d, mainly from gas field LPG sources.

Longer term, however, the lack of refinery expansion, along with a continuation of demand growth, will bring the balance back down to 5 mb/d by 2035. Specifically, the region’s gasoline net length, which emerged in 2020, will disappear by 2030 when the region becomes (marginally) net short in gasoline in the absence of new refining projects.

Middle East products net exports, by country (left) and product (right), 2010–2025



Source: FGE

The two countries that will contribute most to the increase in the region’s product length are Kuwait and Iran, though for totally different reasons.

Kuwait’s products surplus will increase following the completion of the Al-Zour refinery. In contrast, the increase in Iranian product length will mainly be driven by falling liquid demand in the power sector (when fuel switching resumes upon the lifting of US sanctions), combined with a surge in non-refinery LPG supply (when the new, developed South Pars phases ramp up to capacity) which is currently being underutilized or rejected (left in the natural gas stream and sent to the local gas network).

Saudi Arabia, Oman, Iraq, and Bahrain will also see their product (net) exports rise when their refinery projects are commissioned.

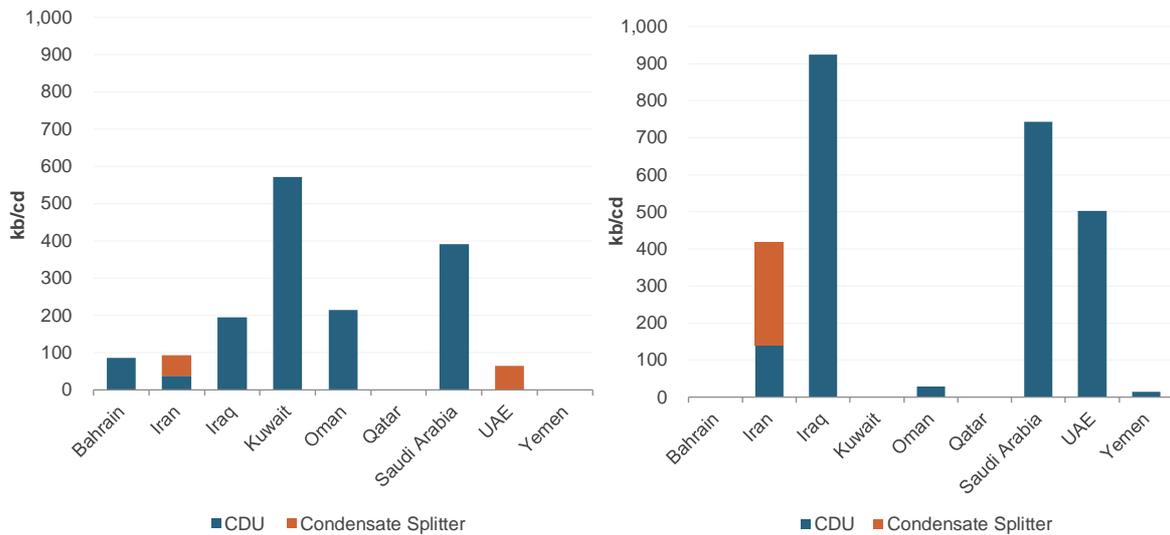


Supported by further refining and storage expansions

The Middle East is home to the world’s second-largest primary capacity additions (~1.5 mb/cd, ‘million barrels per calendar day’) after the Asia Pacific (with 2 mb/cd of capacity additions).

Sizeable expansions are expected in regional hydrocracking (262 kb/cd) and cat cracking (144 kb/cd), along with a massive increase in distillate hydrotreating (almost 1 mb/cd), and residual desulphurization (460 kb/cd).

Middle East primary capacity additions (by 2025): firm/likely (left) and possible/proposed (right)



Source: FGE

There are currently no firm or likely projects scheduled for after 2025, but there are many projects proposed across the region that may emerge later for completion post-2025. The region aspires to add even more refining capacity, all driven by NOCs and governments.

Typically, refining projects never really die in the region, but tend to go back on the shelf until a new minister/manager decides to bring them back on the table. We count around 2.6 mb/cd of potential primary capacity in the region (mainly in Iraq, Saudi Arabia, UAE, and Iran) waiting for governments funding, or hoping to attract private investment, whether local or foreign.

Along with these refining capacity expansions, the Middle East Gulf countries have been adding to their product storage tanks (such as capacity expansions in existing terminals in Fujairah and Sohar, and new storage sites and terminals in Duqm and Al-Zour).

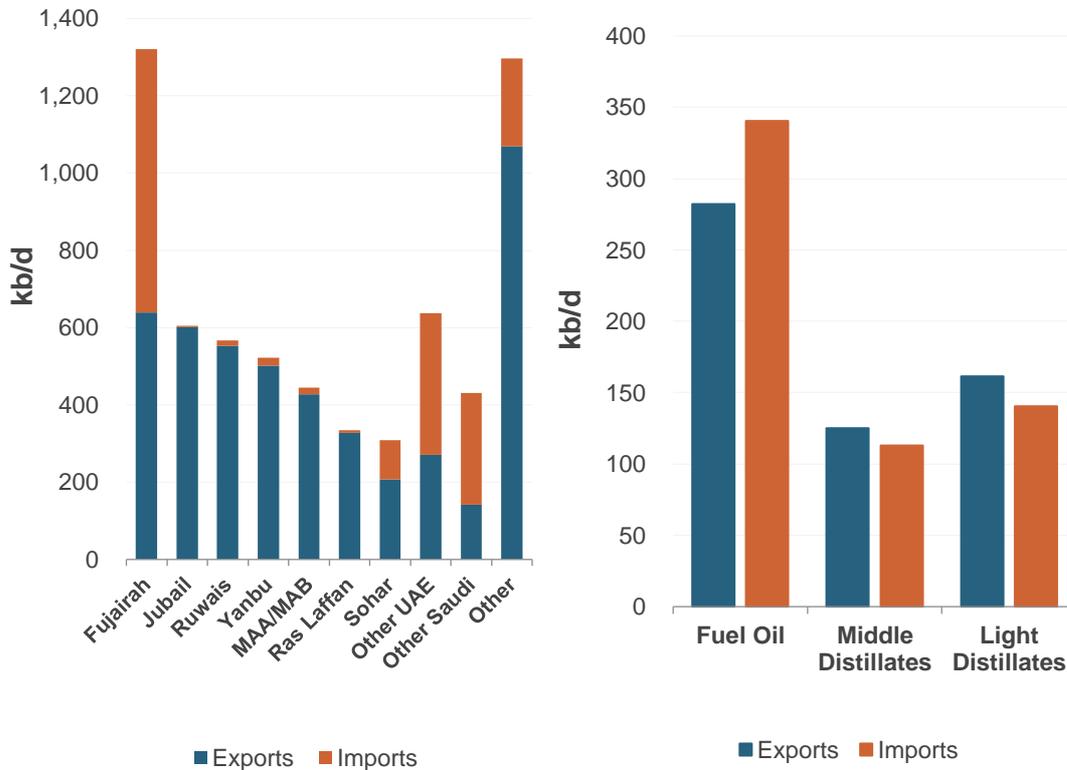
Fujairah’s significance grows...

As a result of the capacity expansions outlined above, Fujairah has played a key role as a pricing hub. This is for a number of reasons:

- **Product hub:** Fujairah is home to nearly 20 per cent of the region’s total products trade (excluding LPG). In terms of products exports, Fujairah ranked first in 2019 with some 640 kb/d of total products exports.
- **Infrastructural:** refinery expansions have increased the need for storage and blending facilities. One of the main contributors to Fujairah’s sizeable products trade is it having been the bunkering hub in the region for nearly all tankers visiting the Gulf (Fujairah supplies nearly 20 per cent of world bunker sales). This was made possible by the UAE and Fujairah port authority having provided all the necessary infrastructure, as well as favourable business terms and regulations. Most of the major products traders (including NOCs such as Aramco Trading) were thus attracted to the UAE, to either base their Middle East operations out of Dubai/Fujairah, or to invest in storage tanks and other related operations (such as refining and blending operations of Vitol and Uniper) in Fujairah. Being outside the Strait of Hormuz—a key geopolitical chokepoint—has also supported Fujairah’s status (given the added financial benefit of being marginally cheaper to load/visit Fujairah due to insurance premiums related to being inside the Strait).



Middle East 2019 products trade by terminal (left)—Fujairah 2019 products trade by product (right)



Source: Kpler

Based on the above, Fujairah has emerged as a natural candidate to develop a reference pricing point to anchor independent price assessments. Like other logistical gateways for product pricing (such as Med or ARA), Fujairah has also been promoted as a basis port in which trades at other ports across the Gulf are captured.

Driving independent assessments

It was the above context which prompted Middle East NOCs to apply pressure on Platts to launch FOB Fujairah outright prices in 2016 for the following products: 95 RON gasoline; 10 ppm sulphur gasoil and 500 ppm gasoil; jet fuel; and 380 CST high sulphur fuel oil (HSFO).

The outright Fujairah flat price is calculated based on Platts’ assessment of spot premiums or discounts for FOB Fujairah cargoes (versus MOPAG netback assessment) and the MOPAG Strip.

$$\text{Outright FOB Fujairah} = \text{MOPAG Strip} + \text{Differential to netback assessment.}$$

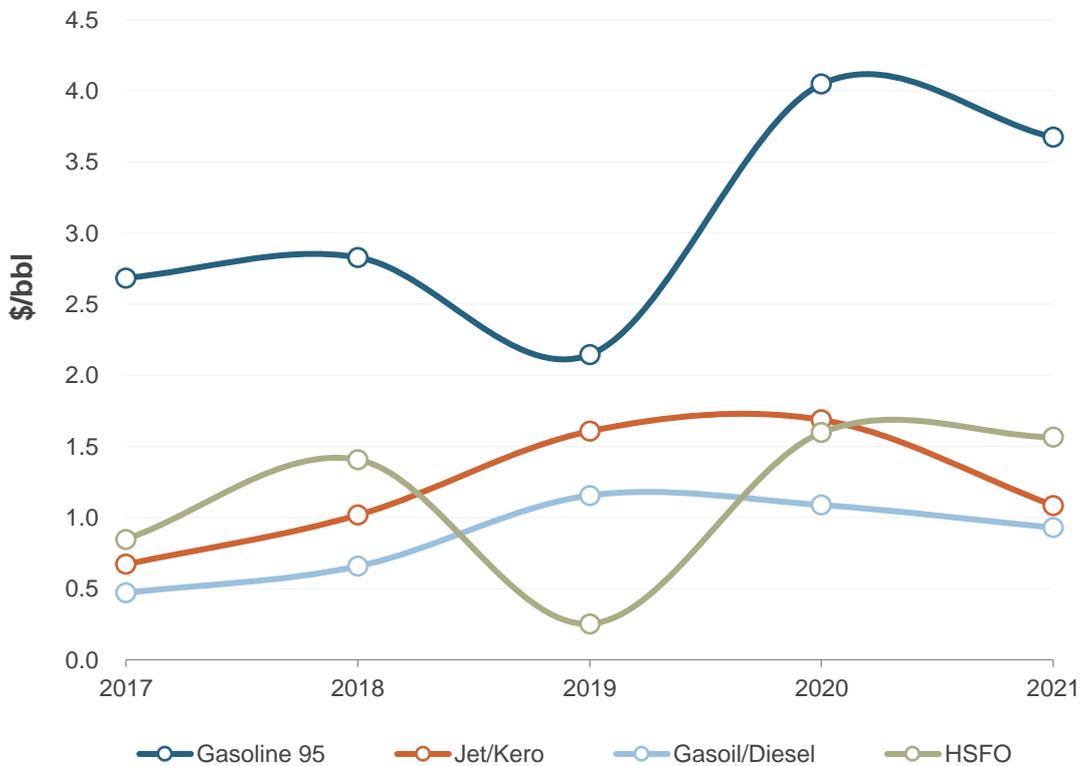
The daily MOPAG Strips are derived from MOPAG swaps, which settle on Platts MOPAG netback assessments and represent the derivative values 20–40 days forward. Platts uses Balance Month and Month 1 swaps to derive the MOPAG Strip for the first 10 day of the month, and then Month 1 and Month 2 swaps for the rest of the month.

Critically, independent assessments have been a valuable tool for reflecting values and trends not always captured by netback values. These include:

- **Higher values:** As the figure below shows, FOB Fujairah (outright) prices have been consistently assessed higher than netback prices since their launch in October 2016. The differentials narrowed (and at times flipped into negative) at certain times, due mostly to fluctuations in the tanker market, but otherwise have been fairly stable over the last 4–5 years, with an average of around 0.5–1.5 \$/bbl for middle distillates and fuel oil and 2.0–4.0 \$/bbl for gasoline.
- **Demand seasonality:** FOB Fujairah (outright) values have captured more accurately fuel oil consumption patterns for power generation during summer months.



Annual product price differential—outright (spot) vs netback



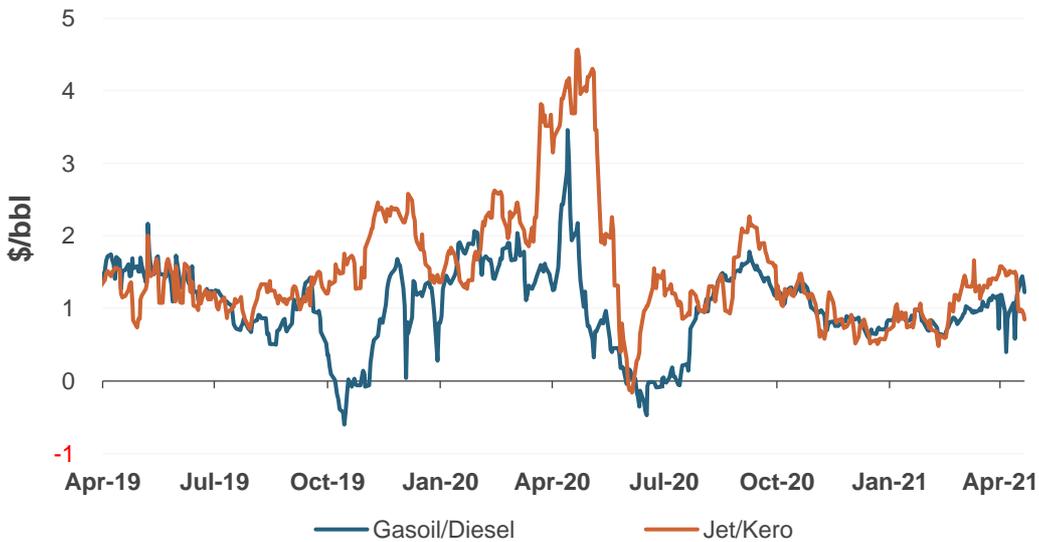
Source: S&P Global Platts

- Tradable value of products not distorted by freight volatility:** COVID-19 provided the clearest example of this trend when FOB Fujairah outright prices for jet fuel, for example, were assessed at \$14.9 in 2H-April 2020 versus \$10.8 for MOPAG! Importantly, the extreme events of 2020 highlighted the trade-off for Gulf refiners: either accept freight volatility or move directly to FOB Fujairah values, a less liquid and proven market compared to Singapore. Regardless, the distorted value of Middle East products has prompted Platts to amend its methodology by now using independent spot prices if freight netback values fall either to a value of zero or below zero.
- Fujairah’s role as an aggregator for Gulf market activity:** Fujairah’s role as an anchor point to capture bids, offers, and trades from neighbouring ports in the Gulf (including but not limited to main ports such as Ruwais, Jebel Ali, Jubail, Ras Tanura, Shuaiba, Mina Abdulla, Mina Al Ahmadi, Sohar, Sitra, and Ras Laffan), with these values normalized back to Fujairah.
- Fuel oil spreads:** flat price assessments for fuel oil become important tools for traders seeking to hedge barrels, or understand the price risk for dirty tanker trade between Middle East and Asia.
- Arbitrage flows:** Fujairah outright price, a sum of the MOPAG strip and differential, is also a useful way to understand whether or not the arb is open or closed for products from the Middle East to Europe. Flat price assessments provide an important pricing signal on the arbitrage economics of product trades. The chart below, for example, demonstrates this for middle distillates.

As the below figure shows, outright spot is higher than netback values by 1–2 \$/bbl, a trend driven by the Middle East Gulf’s growing role as a swing market. Singapore netback values actually represent a netback from the market of last resort (especially for middle distillates, which are mainly exported to Europe and Africa). The premium for spot versus netback shown by the below figure represents the pull from the west. At times when demand is weak, the spot diff is negative, signalling a closed arbitrage. In this light, Fujairah outright price assessments add to the pricing ecosystem in the region by capturing arbitrage trades.



Middle distillates—daily outright (spot) vs netback price diffs



Source: S&P Global Platts

Ongoing trade-offs

Despite the above, Gulf refiners continue to use the traditional netback model to price their products. While Fujairah outright price assessments capture certain trends more accurately and yield higher values than a netback system, reluctance to make a full-fledged switch to product formulae pricing demonstrates the importance of liquidity being king in benchmark pricing.

FOB Fujairah outright prices comprise two elements: MOPAG strip and spot differentials. The quality of assessment for these components depends highly on liquidity in derivatives and (spot) trade volume, respectively.

From October 2020 until today, for example, Platts MOC has captured 11 bids in the window for the Arab Gulf, concentrated on 500ppm gasoil, with two key participants: Vitol and BP.

In this light, more work is needed to be done before any major shifts away from Singapore netback values are made. This is due to:

- Fujairah trade activity being largely concentrated by a few small players. Concerns also continue to linger around transparency, although there are positive efforts being made to publish more frequent storage and trade data.
- Singapore is a more liquid market with multiple players, allowing for hedgeability.

Nevertheless, as COVID-19 has demonstrated, Fujairah outright prices have served a useful purpose highlighting the risks of freight volatility in distorting product values. As Fujairah’s significance grows, particularly given its central importance to ADNOC’s future ambition, Fujairah flat price assessments will likely grow in the Middle East product pricing ecosystem.

THE SHIFTING DYNAMICS OF THE MIDDLE EAST JET MARKET

Julien Mathonnière

The year 2020 will be remembered as an *annus horribilis* for refined petroleum products—especially jet fuel. The COVID-19 pandemic wiped out nearly 40 per cent of the world’s jet fuel demand in 2020, which accounted for one third of the 8.5 mb/d plunge in refined product consumption. Jet fuel is a key driver of global demand, representing about 8 per cent of the world’s oil consumption in a normal year.

Global passenger traffic fell by 65.9 per cent compared to 2019, its sharpest decline in history, according to the International Air Transport Association (IATA). Air cargo demand fared much better with a 10.6 per cent annual drop in 2020. And it is now clear that the first half of 2021 will be worse than anticipated, owing to further travel restrictions in response to new virus variants.



As the world's primary exporter of jet fuel to the global market, the Middle East has suffered the double whammy of reduced crude oil demand and lower jet fuel uptake from regional and international airlines. For a region known as a nexus of jet fuel production, this demand destruction swelled the surplus of aviation fuel at the same time as it cut into export flows. A disproportionate share of the jet supply that flows into Europe and Asia is produced in the Middle East, as well as in India.

Jet fuel belongs to the broader family of middle distillates, which include diesel, gasoil, and dual-purpose kerosene. The sophisticated refineries in the Middle East have cornered the export market for refined products, accelerating downstream rationalization and making Europe even more dependent on imports.

The Middle East is the world's fourth-largest jet fuel market behind Asia, North America, and Europe, with a 10 per cent market share. Its jet fuel demand was on a strong growth track prior to the pandemic, after regional carriers built formidable long-haul route networks. Airports in Dubai and Abu Dhabi in the UAE and Doha in Qatar became key refuelling hubs for flights between Europe and Asia.

The region is home to the so-called ME3 carriers, namely Emirates Airlines in Dubai, Etihad Airways in Abu Dhabi, and Qatar Airways in Doha, which operate a 'hub-and-spoke' model that radiates long-haul flights to multiple destinations around the world. Those airlines invested in large fleets of jet-guzzling, wide-bodied aircraft, using economies of scale to join the ranks of major network carriers. To offset non-existent passenger traffic, the carriers pivoted to air cargo, becoming critical conduits of vaccines and medical supplies to countries around the globe.

Flows

With aviation established as a vital business for the Gulf economies, the COVID-19 impact has hit the airlines as well as the National Oil Companies selling jet fuel and/or crude oil feedstock to international customers. The Middle East benefits from an abundant, cheap indigenous crude supply, and its central location gives the region access to both Western and Eastern markets.

Europe is the world's largest importer of jet fuel. In 2019, the region imported 23.5 million tons of jet kerosene, with the UK, France, the Netherlands, and Italy absorbing more than two thirds of the volume. After the new, sophisticated plants in the Middle East prompted a spate of refinery closures in Europe, the region typically sourced more than a third of its jet fuel requirements from the Middle East and from farther out in Asia. In 2019, Saudi Arabia sent 4.9 million tons to Europe, the UAE 4.7 million tons, Kuwait 1.7 million tons, and Bahrain 1 million tons.

The 2020 slump created a massive supply overhang, pushing prompt jet prices into steep discounts to later-dated deliveries, a situation known as 'contango'. As the global economy sank deeper into the crisis, so did the market contango. With nowhere else to go than into storage, Middle East jet fuel flowing to Europe started to swell the Amsterdam–Rotterdam–Antwerp (ARA) inventories, which topped out at 1.2 million tons in November 2020, according to *Insights Global*. But onshore tanks were full everywhere, not just in ARA.

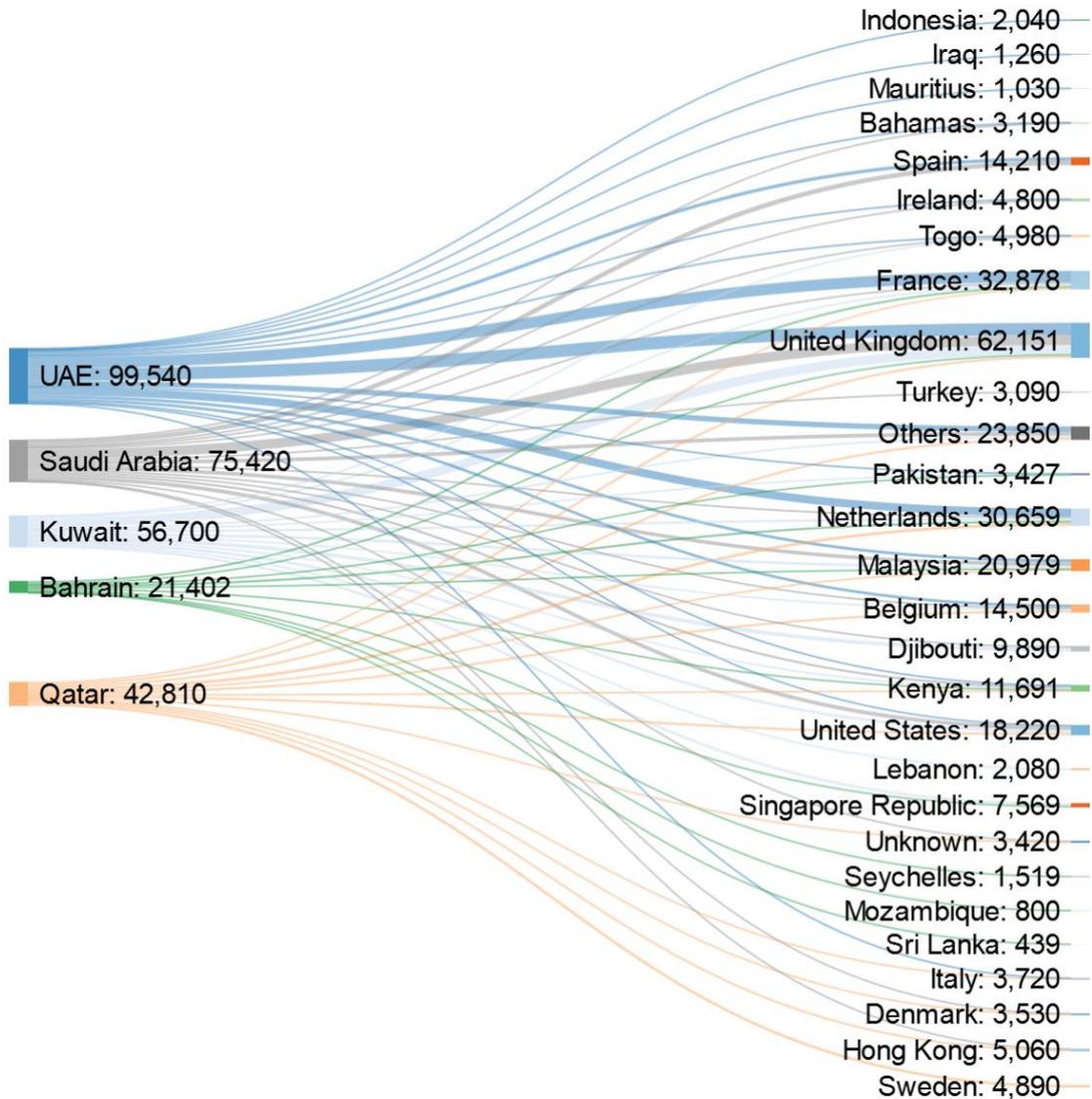
By May 2020, traders began to rush for extra tank space, and Middle East jet cargoes to stack outside the ARA zone—notably offshore Southwold on the UK East coast and Lyme Bay in the English Channel, where floating storage peaked at 2.7 million tons in August 2020. Refined product stocks at Fujairah, the main product storage point in the UAE, shot up by 32 per cent in the space of four weeks in May, to more than 30 million barrels.

A large share of jet exports from the Arab Gulf lands in the UK, the Netherlands, and France. In 2020, those three countries accounted for 35 per cent of jet flows from the Gulf's main five exporters, namely the UAE, Saudi Arabia, Kuwait, Qatar, and Bahrain. But when European storage reached saturation in May, Middle East refiners started to push more jet molecules into their ultra-low-sulphur diesel (ULSD) streams and exports, which had suffered less demand destruction. Finished jet was also bought and blended into diesel in Europe.

Middle East refiners eventually trimmed their jet output and exports to Europe, turning their interest to Asia Pacific. The Asia Pacific region is the world's third-largest consumer of refined products. Arbitrage economics have typically favoured the shipment of Middle Eastern jet fuel to the West, and jet cargoes were rarely heading to Asia. But strong growth in air travel demand from Asia has altered those patterns.



2020 Jet fuel exports from top 5 Middle East exporters (in barrels per day)



Source: Kpler

So far in 2021, first-quarter jet fuel flows from the top three Middle East producers—the UAE, Saudi Arabia, Kuwait—to Singapore have doubled from the same quarter a year ago, at around 16.3 million barrels. Those producers are also shipping 72 per cent more jet to Japan, while quarterly jet exports to Malaysia have nearly tripled year-on-year, at more than 10 million barrels. Pakistan has also registered a significant increase in Middle East jet imports.

Arbitrage patterns

As a result, jet fuel traders have been seeking for more flexibility, with East/West port discharge options in their supply contracts. Seasonality, price dislocation, and regional inventory levels dictate the direction of the physical arbitrage flows.

Middle East refiners are among the largest suppliers of distillates (mostly gasoil) to Europe in the summer and to Africa during the winter. The Middle East also typically supplies Malaysia and the hubs in Singapore and Hong Kong, as well as countries like Indonesia, Pakistan, and Japan.

In Europe, jet fuel demand usually increases in the spring and spikes in the summer, during the peak holiday travel season. In Asia, jet demand tends to surge during the Lunar New Year in February, the longest annual holiday in the region. In 2021, however, a second wave of COVID-19 outbreaks, and governments discouraging travel in North East Asia, has dampened jet fuel demand by about 45 per cent compared with a year ago.



Beyond seasonal patterns, jet fuel traders deciding where to send their jet surplus would typically compare the front-month ICE gasoil exchange of future for swaps (EFS) with the so-called Singapore free-on-board (FOB) regrade spread, which acts as a proxy hedge for jet fuel in tracking the East/West arbitrage.

The ICE gasoil EFS measures the differential between the Singapore cash (or swap) market for 10 ppm gasoil and the ICE low-sulphur gasoil futures. It is a key indicator of the arbitrage flows between Asia and Europe. The Singapore regrade spread measures the relative strength of the jet fuel/kerosene complex to 10 ppm gasoil.

Sending jet fuel to Europe becomes attractive when both the EFS and Singapore regrade spreads are negative. When arbitrage chokes the legacy Middle East flows to Europe, jet fuel ends up in Asia.

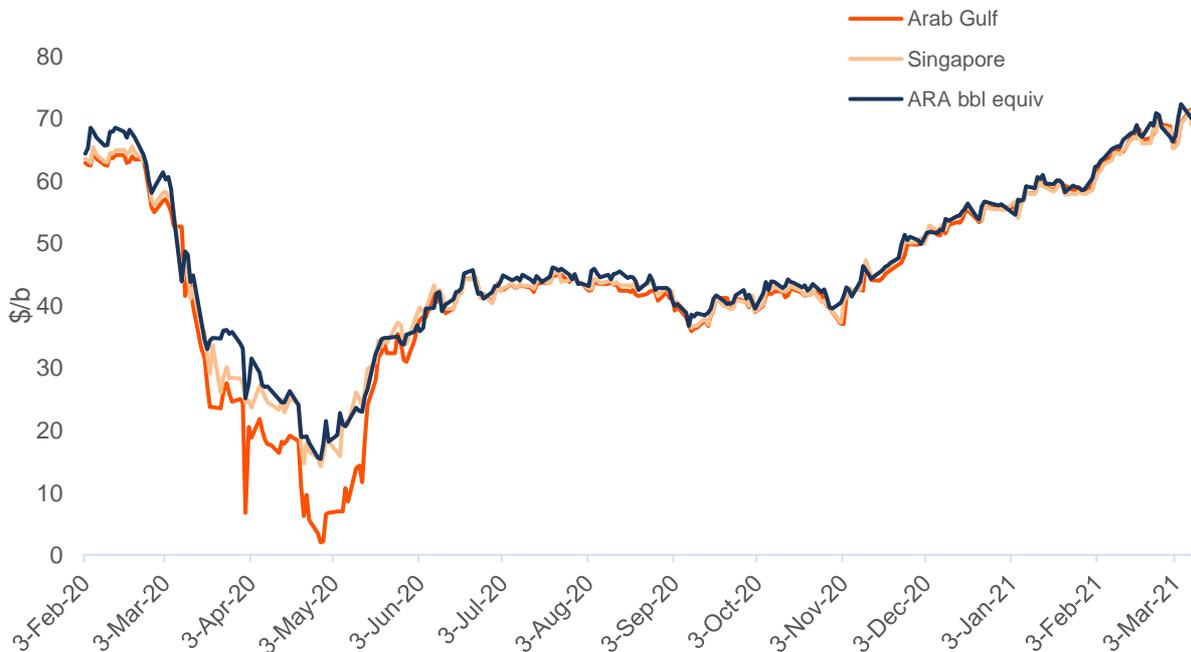
Pricing

Prices for petroleum products in the Middle East are measured as a relative value to the Singapore hub, owing to the bulk of fuel demand being in Asia. For Middle East jet fuel, freight netbacks are priced off Singapore. Product storage capacity at Singapore, in onshore tanks, underground caverns, and tankers at sea is much bigger than in Fujairah (95.8 million cubic metres by 2022), which also lacks the centrality, coastal refining capacity, and the distribution logistics of Singapore.

ADNOC and Kuwait Petroleum Corporation (KPC) sell their jet on free-on-board (FOB) term contracts. They are priced against MOPAG—or Mean Of Platts Arab Gulf—and are typically renegotiated every 6 to 12 months. Saudi Aramco had made huge efforts to sell on a cost insurance freight (CIF) basis into North West Europe, in order to cash in on the trading margin. They have storage in Europe and should have benefited from the market contango. But that didn't work so well in 2020 after jet demand collapsed, prices plunged, and margins evaporated: Aramco sent 63 per cent less jet to Europe last year than in 2019, the biggest drop of any overseas supplier.

The lockdowns, and the subsequent paralysis of the global economy during the second quarter of 2020, decimated global air travel demand. With the grounding of much of the global aircraft fleet, jet fuel demand collapsed and jet prices fell in its wake. Middle East jet prices fell faster and deeper than in other regions, but this may not necessarily reflect regional pricing dynamics. Because they are a netback to Singapore, they include a freight component, which also slumped at the time.

Middle East jet fuel prices plunged deeper than elsewhere (jet fuel prices in \$/bbl)



Source: OPIS, Energy Intelligence



At the outset of the slump, in March and April 2020, Middle East refiners continued to ship jet fuel to the West. Traders in Europe kept gorging on cheap jet, taking advantage of the market contango to make cash-and-carry trades, putting jet in storage, and waiting for prices to rebound.

Imperfect hedge

In the Middle East, like elsewhere, the huge drop in jet fuel prices put airlines in a tough spot, causing their fuel hedges to be deemed ineffective under applicable reporting standards. Fuel hedging is a standard risk management practice that enables airlines to insure against price increases by making advance purchases of jet at a fixed price.

To do so, carriers can either buy jet fuel swaps or oil forward contracts. They generally prefer crude oil futures because market liquidity is greater, making the hedge more cost effective. Companies hedge on the basis of their price assumptions for the year. They buy crude hedges far out for liquidity, then convert them to gasoil and subsequently to jet swaps the closer they get to contract maturity.

But when jet prices crashed below the levels they had hedged at in the spring 2020, airlines incurred substantial mark-to-market losses, reflecting their obligation to pay the higher hedged price, rather than the cheaper market price. A lot of airlines abandoned their hedging programmes last year for obvious reasons. Quite a few don't hedge at all, having been burnt too many times.

Under provisions of the International Financial Reporting Standards (IFRS), rather than hedging the full cost of jet fuel, airlines can just hedge its main crude component, so long as it is 'separately identifiable and reliably measurable'. Jet fuel can be produced from different types of crude linked to different oil benchmarks.

Therefore, the relevant crude oil risk should be based on the physical crude oil actually used in the hedged product, to avoid ineffectiveness. Middle East jet fuel hedges should hence be done against the Dubai–Oman benchmark, but other instruments offer superior liquidity, including the highly liquid Singapore gasoil and jet fuel swap market, as well as the Brent low-sulphur gasoil futures, which is the predominant grade of distillate fuel in Singapore.

For Emirati airlines, the launch of ICE Futures Abu Dhabi (IFAD) in March 2021 could provide an even better hedge. The contract is trading Murban oil futures. Murban is a light, sour crude prized for its low sulphur content, by Middle East standards, and is produced by ADNOC. Murban yields a large fraction of middle distillates—including jet fuel—and a petrochemical-oriented naphtha cut.

Refining strategies

Jet demand growth prior to the pandemic spurred major refinery upgrades, which has expanded the region's jet fuel surplus even as local usage continued to grow. The most significant excess capacity is forecast for the Middle East, with a 1.4 mb/d surplus expected by 2023, according to the International Energy Agency.

Middle East plants were initially built to meet growing regional demand for gasoline (and to back out imports) with high middle distillate yields, which are partly a function of their domestic crude slates. Jet fuel traffic to Europe existed long before Middle East refiners began cleaning up their gasoil streams to sell ULSD alongside.

The ageing downstream infrastructure in Europe was designed for gasoline production and could not cope with the region's gradual shift to diesel. That initially opened the door to diesel from the Middle East and Russia. New-built refineries East of Suez are designed to maximize the output of middle distillates. They are targeted at cleaner fuel sales to Europe (such as Kuwait's Clean Fuels project) and to Asia.

In the face of those capacity additions, the refining sectors in North West Europe and the Mediterranean have continued to cut capacity through the years. The toll of the pandemic, the energy transition, and changing demand patterns have accelerated the pace of conversions or closures. Refinery runs in the Middle East are expected to overtake those in Europe around 2030.

The 2020 slump has shown the flipside of this capacity expansion, with reduced refinery utilization, not only in the Middle East but globally. Refiners responded to the collapse in jet demand by diverting intermediate feedstocks into their diesel stream, or by blending jet directly into the diesel pool.



Core Middle East refining capacity*

(barrels per day)

	Owner	Total capacity in barrels/day	Planned upgrade	Expected date
Bahrain				
Sitra	Bapco	267,000	Expansion	2021
Kuwait				
Al-Zour	KPC	615,000	Launch	2021
Mina al-Ahmadi	KNPC	466,000	Upgrade	n/a
Mina Abdullah	KNPC	270,000	Upgrade	n/a
Oman				
Sohar	State of Oman	198,000		
Duqm	Joint	230,000		
Qatar				
Ras Laffan	QP	146,000		
Saudi Arabia				
Ras Tanura	Aramco	550,000		
Riyadh	Aramco	126,000	Upgrade	2022
Jazan	Aramco	400,000	Launch	2021
Yanbu	Aramco	245,000		
Petro Rabigh	Aramco-Sumitomo	400,000		
SAMREF-Yanbu	Aramco-ExxonMobil	400,000		
YASREF-Yanbu	Aramco-Sinopec	400,000		
SASREF-Jubail	Aramco-Shell	305,000	Expansion	n/a
SATORP-Jubail	Aramco-Total	400,000		
United Arab Emirates				
Abu Dhabi	ADNOC	85,000		
Jebel Ali	Enoc	140,000	Expansion	n/a
Ruwais	ADNOC	837,000	Expansion	2022
Ruwais (vicinity)	ADNOC	400,000	Launch	2025
Total		6,880,000		

* Excluding Iraq, Iran, Jordan, and Syria Source: Company data

Recovery prospects

For Middle East refiners catering to the international market, the recovery is likely to be protracted.

A rebound in air travel is dependent on the progress of global vaccination campaigns, as well as health screening protocols, to jump-start transcontinental flights. Europe's air traffic is still down two thirds from pre-pandemic levels, with borders either closed or protected by strict testing and quarantine requirements. Bellwether jet stocks in the Amsterdam–Rotterdam–Antwerp hub stood close to 1 million tons on 18 March, according to *Insights Global*, more than double where they were this time last year.

Some prompt jet demand has come from Asia, where China's relatively large domestic market has rebounded to pre-COVID levels even as international flights are still restricted. Australia and New Zealand should provide a larger outlet for jet fuel exports this year, with the impending shutdown of refineries in those countries.

Any sustained rebound in jet fuel demand depends on the resumption of long-haul flights. Those services burn about 35 times more fuel than regional flights and make up more than a third of global jet fuel demand, the IEA estimates.

The assumption that air travel will pick up in the second half of this year underpins the latest *Energy Intelligence* forecast, which shows worldwide jet fuel demand reaching 5.3 mb/d in 2021. While that's a 19 per cent increase from 2020 levels, it is still well below the 7.3 mb/d peak in 2019.



CONDENSATE, THE ODD ONE OUT IN THE FAMILY

Thomas Olney

Condensate occupies a peculiar place within the hydrocarbon family of products, and the market is poorly understood by outsiders. It is used as a refinery feed, mostly in the West of Suez, and as feed to purpose-built condensate splitters (either for petrochemical use or splitting for product export and gasoline production). For this reason, some trading houses look at condensate as a refinery feed (competing with crude), while others see it as a petrochemical feedstock (competing with naphtha).

This competing use often leads to wild swings in prices for the main sellers/buyers depending on how the barrel clears in a surplus/deficit market. During the height of COVID-19, we saw differentials for the main Australian grade—North West Shelf condensate—drop to a discount of 15 US\$/bbl (FOB) versus Dated Brent, as marketers struggled to turn off the taps in the face of collapsing demand, with refiners unable to soak up the excesses. In times of tightness (particularly with the removal of Iran's South Pars Condensate through US sanctions), condensate splitters have been forced to absorb premiums of up to 5 US\$/bbl versus Dubai.

But it is not just condensate supply versus demand exposure that the market has to contend with. Condensates have, by and large, followed regional crude conventions for pricing markers, which adds another dimension in terms of location and specification. Brent/Dubai basis risk is embedded within the condensate market. While one would assume that the market will perform efficiently, the world of condensate is anything but efficient. Movements in Brent/Dubai add to an already complex pricing dynamic for market players.

In this paper, we will argue that a more fungible relationship between a Middle Eastern marker and an Australian marker (if done correctly with a grade that is much closer in specification and more representative) would help to improve the efficiency with which prices can adjust in a condensate market. But most of all, the Brent/Dubai risk, while a consideration, is by far not the biggest element of trading risk for a condensate barrel, and should not be overstated.

Condensate, crude's estranged younger brother

The line between ultra-light crude and gas condensate is often blurred. By the strictest definition, condensate has to be derived from gas. This can be either from non-associated gas fields, such as the massive North Field/South Pars straddling Qatar and Iranian waters, or associated gas from the Eagle Ford and Permian tight oil wells in the US.

After leaving the reservoir, liquids-rich gas has to go through several steps before eventually arriving at a condensate processing plant. First, the raw gas from the wellhead enters a slug catcher (usually), which is a three-phase high-pressure separator that splits the gas and solid contaminants from the liquids. Those liquids that exit the slug catcher are termed *lease condensate*. We also hear terms such as *field* or *stabilized* condensate (given the fact that volatile high RVP material is separated to 'stabilize' the mixture), but certainly **not** plant condensate, which is produced instead from the fractionated by-product wet gas or NGL mix, and is more like light paraffinic naphtha or pentanes plus in nature.

Typically, a barrel of condensate has a combined naphtha yield greater than 50 per cent. Its API number typically ranges between 55 and 70, although some grades, such as Indonesia's Senipah (52.7) and America's Eagle Ford (52), are heavier. We even see some commingled grades of crude/condensate like Akpo (as heavy as 45.8) in Nigeria classified as condensate, giving rise to protests by OPEC compliance monitors. For our intents and purposes, this does not quite pass the smell test.

The sulphur contents of whole condensates are also exceptionally low compared to crudes. Having zero sulphur is common, while even the percentage of sulphur in sour condensates such as DFC and South Pars only goes up to 0.3 per cent wt, which would be considered sweet when applied to crudes.

Condensate East of Suez, a brief history

The transformation of condensates into a widely traded seaborne product East of Suez was brought about by two converging dynamics in the 1990s:

- The first factor was the development of the South Pars gas condensate field (first production, 1989) and the adjoining Qatari North Field (first production, 1991), providing almost limitless supplies of light gas condensate, rich in naphthenic and aromatic (N+A) content.



- The second was the growth of Asia's petrochemical industry in the 1990s, but particularly post 2000s, and the strong demand for aromatics to feed the growing textile and manufacturing industry.

It was no coincidence that the condensate market that we know finds its origins in this period. Surplus Middle Eastern supply was met by strong demand for aromatics, in particular para-xylenes (the building block in the polyester chain used for nylon and PET plastic bottles). Petrochemical players in South Korea, Japan, and Singapore came up against an insufficiency of feedstock, N+A naphtha, for the new aromatics plants being built in the region.

South Pars condensate (SPC) and deodorized field condensate (DFC) were a perfect fit. With a large N+A naphtha cut, they were seemingly ideal. The only problem was working out how to strip or 'split' out the useful naphtha cut from the rest of the barrel. Existing naphtha splitters were converted for this purpose, while new condensate-only splitters emerged later.

Petrochemical companies in this business decided that they would make the feedstock that they could not get from the market. There is currently over 2.7 mb/d of condensate splitter capacity in operation in the Middle East and Asia, with a combined splitting capacity of close to 1.2 mb/d where the splitter operator is dependent on imported condensate.

Nowadays, the traditional model focused on condensate splitting for aromatics production is under pressure from shifting dynamics in the region. A focus from China to reduce its dependence on base chemicals for its manufacturing industry, and the emergence of the COTC (crude oil to chemicals) model for refineries, is pressuring aromatics-focused condensate splitters in Korea and Singapore.

Refineries such as Hengli and Rongsheng are large textile manufacturers that have opted to reverse-integrate down the value chain into crude oil rather than condensate. The economies of scale of the plants and the focus on paraxylene production is certainly putting into question the long-run viability of splitting naphtha and condensate for aromatics export, with the main import market weaning itself off this dependency on these products. Some aromatics plants are considering this already, while others are reorienting towards domestic requirements for these chemicals.

Condensate and naphtha, always vying for the family's attention

In Asia, the focus on field condensate as a means of extracting certain ranges of naphtha, as well as the consideration of PONA (Paraffins–Olefins–Naphthenes–Aromatics) content for petrochemical use, has meant that condensate, in effect, trades as if it were a grade of naphtha to certain buyers and pricing is derived as such. The ability of various South Korean splitters to swing between condensate and full-range naphtha (up to 120 kb/d in any given month) adds to this competition between the two products, providing optionality depending on price competitiveness between the two grades.

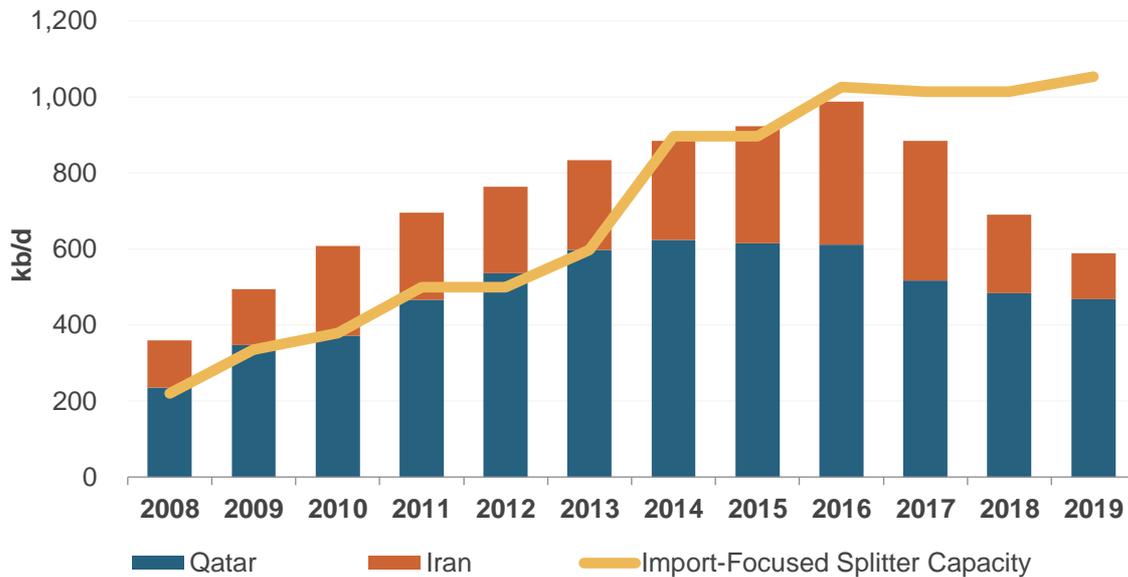
Last year, we saw the intertwined nature of naphtha and condensate clearly. Pressure on the aromatics complex from the giant crude-to-chemical projects in China (Hengli and Rongsheng focused primarily on paraxylene production) was compounded when road transport demand collapsed. A weak PX price forced splitters to discriminate against high N+A cargoes (of naphtha and condensate) with splitters focusing their attention towards condensate with a large light value naphtha (LVN) cut, or indeed just paraffinic naphtha. At one point, Hanwha Total reduced operating rates at its splitters (which can swing both condensate and the full range of naphtha (FRN)), instead opting to import light paraffinic naphtha to feed straight into its downstream cracker for olefins production.

And given this preference for light paraffinic naphtha, with naphtha cracks surging last year given the tightness in the market, we saw refiners look to condensate as a way of shifting their yields in the absence of light crudes and ample availability of condensate. The Chinese saw opportunity in steeply discounted condensate grades with a larger light naphtha cut, seeing an increase in condensate inflows.

While condensate is priced against crude, naphtha is its closest relative by far. It can be a friend but often can be an enemy, seeing a rapid disappearance in demand almost overnight depending on the movement in naphtha vs crude. Understanding this dynamic is often more important than the crude risk that we may see in the market.



Qatari and Iranian exports vs import-focused condensate splitter capacity in the East



Source: FGE

Condensate as a distant relative of gas

While value is primarily derived from the petrochemical value chain and the refined product market (and particularly the naphtha market), condensate is of course a distant relative of gas. Gas/LNG prices play little role in shaping value for condensate, but they do play a part in dictating market dynamics, which can have an impact from time to time.

Of course, condensate producers in the Middle East and broader Asia Pacific are not really focused on drilling for condensate, but instead focus on the gas/LNG production, with surplus associated condensate production largely a by-product. For this reason, many market commentators say that condensate is ‘supply-driven’, pricing down to clear in the market. Obviously, this is an oversimplification as it is highly dependent on the state of balances, but it is certainly true that producers are not so willing to turn off the taps if demand for condensate were to drop off a cliff.

In April and May last year, there was the clearest example of this in the market. As refineries seemed to chase one another to zero with run-cuts, and while splitters struggled to make the economics work with weak aromatics and transport fuel demand, condensate demand evaporated almost overnight. But the Qatari and Australian producers were not easily able to throttle back on condensate supply. The taps remained open and many producers discounted and discounted to clear cargoes in the market, with limited tankage rapidly filling up. At one point we saw North West Shelf drop to -8 US\$/bbl versus Dated Brent (on an FOB basis) with Dated Brent itself in the range 15-20 US\$/bbl.

When two members of the family don’t get along, it creates problems for condensate

By telling the story of the various family members and how this one (condensate) relates to the others, at least the reader can have some guidance in understanding the most important dynamics at the heart of condensate pricing and the evolving market structure. However, we have avoided talking about two conspicuous family members—both Brent and Dubai. Brent/Dubai and the EFS (Exchange of Futures for Swaps) can cause problems, particularly when the two markets seem quarrelsome with one another. We saw this briefly for a period in 2019 with tightness in high-sulphur fuel oil (HSFO) propping up Dubai versus Brent, and more recently over the last few months given the HSFO strength.

At the most simplistic level, sellers have pointed to the role EFS can occasionally play in negotiations. Condensate buyers may evaluate grades priced off Brent and Dubai, and have used EFS to discount Brent-linked grades such as NWS (relative to Dubai-linked grades such as DFC) by the size of the EFS. In certain cases, sellers feel that this approach is being used as a hard negotiating tack on the price for Brent-linked grades, but this ignores key differences in quality and yields between the grades. Specifically, NWS condensate is 70-80 per cent naphtha yield, whereas DFC is relatively more middle-distillate rich. As such, a straight EFS discount to Brent-linked seeks to oversimplify market complexities.



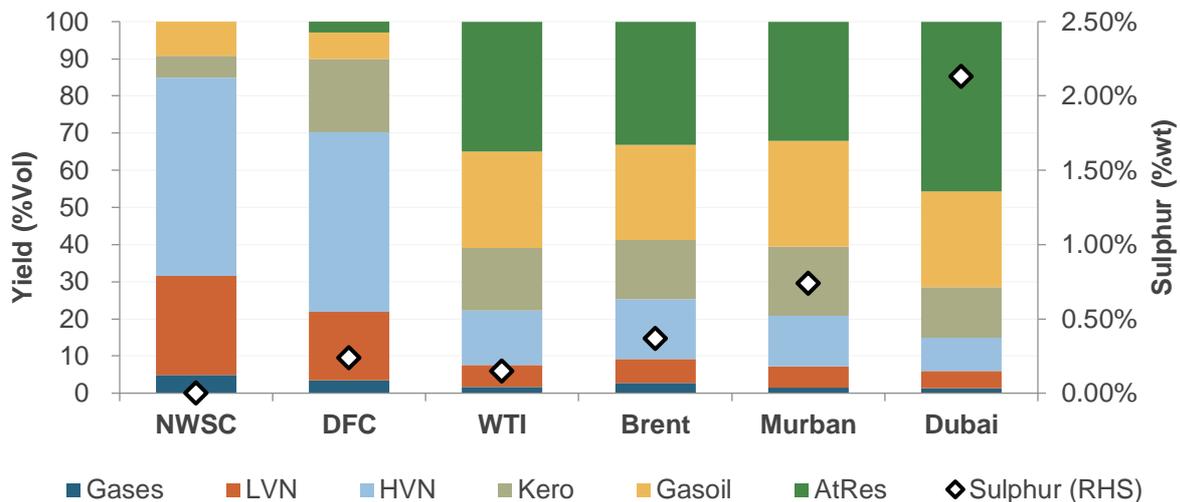
From an FOB buyer’s perspective, the view is that EFS is sometimes poorly understood from the perspective of an FOB seller. EFS is used as a hedging tool to mitigate crude basis risk if they are buying one Brent-linked grade and selling another Dubai-linked grade (or vice versa). Obviously if volatility were to surge in Brent/Dubai EFS, this may leave both buyer and seller pointing to different levels for fair value for price discovery. But from a buyer’s perspective, liquidity is king for a financial instrument, and Brent/Dubai EFS is still by far the most liquid tool for managing this risk.

Adding to this is the complexity that some splitter buyers can pay more for condensate depending on the downstream petrochemical margin, rather than a simple GPW (gross product worth) analysis (which a refiner may be looking at), meaning that buyers and sellers sometimes are not looking at the same value proposition for a condensate grade. The market structure will dictate value in this instance. In a seller’s market, when buyers are short on condensate, sellers can often drive greater value, pushing cargoes into the petrochemical complex (obviously depending on the margin), while in a lengthy market, a cargo will have to clear where there is demand, often competing with crude in a refinery complex.

Is there room for a new member of the family?

The prospect of a new member of the family is quite exciting. Given all the complex pricing dynamics we have discussed above, removing one added complication in discussions between buyers and sellers should be a welcome proposition.

Crude and condensate yields and sulphur %wt



Source: FGE

Murban is a light sour crude oil with a 40.5 °API gravity and a 0.74 per cent sulphur content, and it is produced onshore in Abu Dhabi. It is more similar to both Brent and WTI than Dubai, eliminating some of the HSFO risk embedded within the Dubai contract. Of course, a replacement of Dubai with Murban as the marker would naturally make a Qatari DFC premium more akin, and easily identifiable, relative to a NWSC premium/discount priced against Brent (a more obviously familiar member of the family) rather than a DFC premium/discount versus a sour and medium Dubai marker (please see the chart above).

Physical liquidity underpinning the contract is clearly a factor as well. ADNOC is planning to increase Murban production capacity to 2 mb/d, albeit with COVID-19 in full effect the NOC is some way off reaching this level of production.

There has to be little doubt that conceptually Murban will be much more fungible with the other regional markers (Brent and WTI). Murban does have a 3 per cent higher yield for gasoil, and a slightly higher sulphur content, but is certainly, in appearance, much more similar to the other family members. This would undoubtedly help neutralize some of the complications around the VLSFO/HSFO spread risk embedded within Brent/Dubai, which has become an important factor in driving EFS movements.

However, firstly, we need to be aware that the market will be reluctant to move. For traders, the most important factor is paper liquidity, and paper liquidity and confidence are hard to build. Condensate, being the little guy in Middle East trade, is unlikely to lead the pack of Middle East crudes to Murban, with other grades likely to make the first move. However, if the conditions are right, it could be a sensible transition that may neutralize one sticking point in negotiations.



CONDENSATES: THE TRADE FLOW AND SEARCH FOR A NEW BENCHMARK

Andrew Laven

Condensate is a unique hydrocarbon that exists between crude oil and natural gas. Also known as natural gas liquids (NGLs), it is most often associated with reservoirs containing 'wet gas', but it can also be present during the production of crude oil. Condensate from these sources is also known as 'field or lease condensate', but it can also be produced as 'plant condensate' (also known as natural gasoline) from a gas processing unit. The composition of condensates depends upon the underlying source but it typically has a specific gravity of 0.5–0.8 and is predominantly made up of hydrocarbons such as propane, butane, pentane, and a variety of other, mostly heavier, components. There is no clear separation between crude oil and lease condensate, and as a result they are normally reported together when production levels are discussed.

Condensate can be used for several purposes. At the most basic level it is used as a diluent for heavier hydrocarbons—for example allowing heavy crude to be pumped through a pipeline. It can be blended with crude and processed, or processed in a splitter to separate it into its individual components. Some condensates can even be blended directly into products such as gasoline.

Although condensates are a key component of hydrocarbon products and have a wide range of uses, they have generally 'flown under the radar'. Included in crude oil production numbers, mostly priced using crude oil, and frequently associated with gas, they can be seen as a complicated hydrocarbon. However, as the global energy mix changes, condensates will become a more important stream.

Condensates—an increasing portion of the product feed stock

The current major production centres for condensate are mostly fields that produce condensates naturally. The emergence of the US as a key producer has been mainly due to the growth in production from tight unconventional reserves such as shale oil and gas. The Middle East is estimated to have a third of the world's heavy oil reserves and the potential for tight unconventional production is still to be fully tested. Shale has caused a revolution in the US oil industry and there is no reason not to presume that the same will be true for the Middle East.

There is an accelerating change in the specifications of fuels and the way they are used. Lighter fuels with lower sulphur content and better energy efficiency are the focus. The change in marine fuel specification was a short-term detour, during which heavier fuels became more important, but even in the marine sector consumers are looking to new lighter fuels.

A multi-use feedstock like condensate will be in demand for use simply as a diluent, as increasing levels of production come from reserves of heavy oil. At the other end of the viscosity spectrum, with the energy transition underway, it is inevitable that gas will play an increasing part in the energy mix. Condensate production associated with gas developments will rise and find its way into the supply chain. Light, relatively easy to process, and capable of being directly blended into products, the flexibility of condensates adds to their value, driven by increasing demand for such an adaptable feedstock.

Changing trade flows

Currently, the top six global importers are South Korea, Singapore, China, the UAE, the Netherlands, and India. Korea's recent demand has been relatively consistent, whereas others, especially Singapore and China, have varied depending upon market conditions. The largest producers of condensate are the UAE, Qatar, Iran, and Kazakhstan, although as previously indicated, there is rising production coming from shale oil and gas in the US, and gas production in Australia. Iran and Qatar independently produce a large amount of condensate from the South Pars/North Field development which straddles their marine border. Although most of the recoverable gas will likely be produced by Qatar from North Field, the recoverable condensate is more evenly split. Historically Iran's development of South Pars has been very important to its economy, both for export and the domestic production of gasoline; the Persian Gulf Star (PGS) condensate refinery plays a critical role in managing balances. If sanctions are eased, we should expect to see the development of South Pars accelerate. This may also spur Qatar to increase investment in North Field—although they have concerns over the best approach to maximize recovery, they would also be concerned about Iran essentially pulling reservoir pressure down and impacting Qatari production.

Condensate production in the Middle East is increasingly being used within the region, reducing exports, and those that do take place are generally into Asia. On the back of more production and less availability from the Middle East, US exports have been growing—primarily into Asia and Europe. There are also some minor flows from West Africa and North Africa into Europe, the Middle East, and Asia. These changes are likely to continue as the Middle East continues to refine more products, retaining



more condensate locally, and as gas production increases in different parts of the world. The big uncertainty here will be Iran and the US sanctions. If the South Pars development is accelerated, much of that production is likely to be exported to Asia, reducing the flows from the US to Asia.

In short, as the Middle East continues to use its own production, condensate will flow from the US and Africa into Asia, although increases in Iranian production will likely compete for this business if sanctions are lifted for a significant period of time. Europe, which is unlikely to see significant refinery upgrading or expansion, will likely remain at today's demand levels.

Condensate pricing

Most condensates are priced on the basis of a benchmark crude—either at a premium or a discount depending upon demand. That the condensate appears to price at a similar level to the crude shouldn't be taken to mean that there is a close relationship. Most crude is priced on the basis of the value of the components that make up the crude—its gross product worth (GPW). But it should be remembered that even the purchase price of crude is not set by the GPW. It does, however, serve as an indication of likely prices.

The market has developed a relatively small number of benchmarks that are used to price crude oil and products. Pricing agencies such as Platts and Argus publish many prices, but generally purchases and sales are agreed on the basis of a subset of these. For crude, the majority of deals use either WTI or Brent. These benchmark crudes are very liquid and, even more importantly, the contract and how it reacts to changes in the market is well understood by the market participants. Using them as the base price for another commodity is not an issue, as long as the premium or discount—the cash differential—does not vary wildly.

On the surface, it would appear that using a crude benchmark to price condensates is a suitable approach. However, reality indicates that this may not be as appropriate as we would like it to be. The Australian North West Shelf condensate prices are based on Dated Brent. If we look back at the period during 2020 when oil prices fell dramatically, the discount of NWS to Brent also increased—threatening to take the price negative. The rationale for having such a large differential is not clear, and prompted buyers and sellers to consider a 0 \$/bbl price floor. Ideally the differential to a suitable benchmark should remain within a relatively tight band—so this clear disconnect undermines the validity of Dated Brent as the price basis for NWS condensate.

If you compare the assays of NWS and Brent, and Qatar condensate against both Dubai and Murban, it is apparent that the condensates are extremely different from the crudes. On the basis of a GPW calculation, both condensate streams would be expected to price very differently from the crudes. Although, historically, there have been assessments of condensate price, unfortunately there hasn't been a condensate benchmark. As above, a benchmark principally requires two aspects if it is to be successful:

- The benchmark has to have sufficient liquidity so that buying and selling is easy and its price accurately reflects the market.
- The price differential to the associated product the benchmark is being used to price should be relatively small and reflect the change in relative values accurately.

Unfortunately, the common ground between the sellers and buyers of condensate is typically a crude benchmark such as Brent. Although on occasions there may be volatility in the differential to a crude benchmark, significant liquidity is a major factor, and as a result currently remains the most appropriate approach. Some may want to sell condensate on the basis of a product benchmark—this can work for local sales where the planned use is clear, but it can restrict the market by introducing apparent complexity into the pricing. A large refinery blending feedstock will often prefer a crude benchmark, as this makes the comparison of feedstock prices easy. This explains why WTI and Brent have been dominant, with Dubai also being used in conjunction with Brent for pricing.

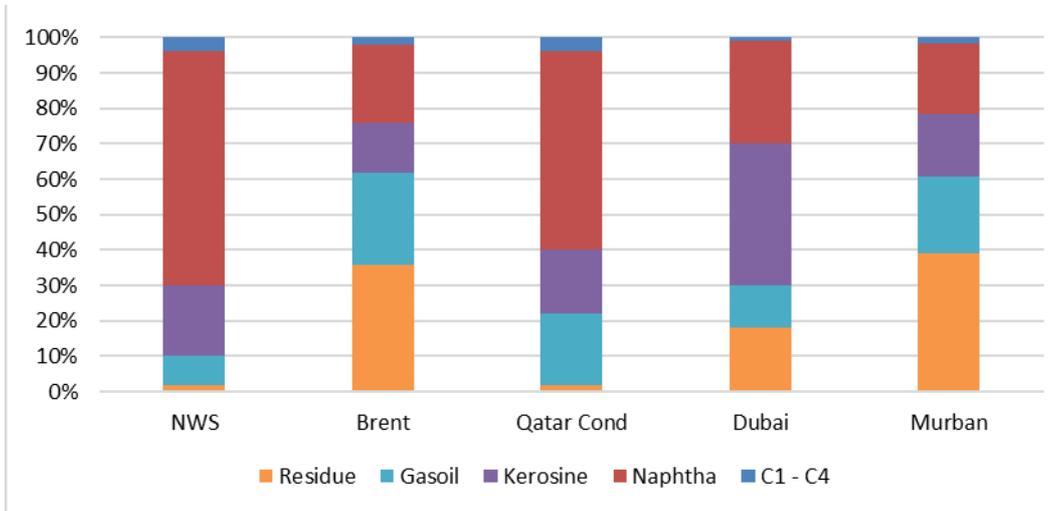
Condensate's impact on Middle East pricing

Therefore, as a broad generalization, and whilst there are obviously exceptions, crude oil is priced on the basis of the location of production, while refined products are priced on the basis of the location of demand. Condensates are neither crude nor products, and much of the flows result in sales being made further away from their production. This geographic dislocation makes it more difficult to align crude-based pricing, but despite this the demand for condensates means that the current pricing



model is likely to remain.

Assay NWS vs Brent and Qatar vs Dubai and Murban



Source: Various Crude Assays

In the Middle East, there is an increasing alignment between production of condensates and regional demand. This should be seen as supporting the need for a Middle East benchmark. However, the GPW of Qatar condensate will be very different from any likely Middle East crude-based benchmark, with virtually 40 per cent of its content being middle distillate and 60 per cent being naphtha. For blending into gasoline, a gasoline-based price would be ideal, for use in a splitter to produce distillates, a price based on gasoil would be better, while for blending with crude, a crude-based price may be more suitable. As condensate can be used in different ways, and the best approach to pricing differs depending upon the use, it is apparent why crude-based pricing is more common.

The focus then shifts to which crude benchmark? For condensates produced and sold for use in the region, a crude benchmark that reflects accurately the fundamentals of the region would provide significant benefits for producers and consumers. Delivering a regional crude benchmark to replace WTI or Brent or Dubai, which is strongly linked to Brent, has proved to be a challenge. If it were to be successful, it would make sense to price regional condensate based on the regional benchmark. Unfortunately, the market is quite fickle and slow to change, and the momentum which supports both WTI and Brent is difficult to overcome.

CRUDE VERSUS PRODUCTS—A SIMPLE CHOICE? DO CHANGING OIL FLOWS FAVOUR INVESTMENTS IN CRUDE OR PRODUCTS TANKERS?

Tony Foster

On the odd occasion that oil tanker charter rates run hot enough to be reported on in the wider press, casual readers may wonder idly what kind of returns tanker owners earn. However, the headline-making highs of the notoriously volatile VLCC (Very Large Crude Carrier) sector do not characterize the tanker market as a whole. What of other times and other types of tankers? How do shifts in the geographical centres of oil production, refining capacity, and consumption growth affect crude and oil products trade flows and what impact does this have on tanker demand and, ultimately, shipowners' returns?

The last decade saw the emergence of the shale industry transform the energy landscape in the US, altering global flows of crude and boosting the crude tanker market. This coming decade will bring the construction of new refineries in the Middle East and Asia feeding demand growth for oil products East of Suez. Will the shifting flows of products cargoes prove a similar boon for the products tanker markets? On balance, the answer is yes, it probably will. Does this mean the outlook for products tanker investments is more positive than for crude tankers? Not necessarily.



Ebbs and flows in crude and oil products trade

At the most fundamental level, the movement of oil across the globe is necessitated by the geographical separation of the centres of oil production and the centres of end-user consumption, but the ability to direct physical supply in response to price signals also enables the market to function efficiently and competitively. While there are numerous drivers that determine the flow of crude and oil products from one part of the world to another, over the last decade, several trends have been disruptive enough to influence the tanker markets in a discernible manner.

Demand for shipping capacity is most often represented by the quantity of cargo carried multiplied by the transport distance (typically tonne-miles)—a metric that better reflects fleet utilization than cargo volumes alone. For example, between 2009 and 2019, while global oil production (excluding natural gas liquids (NGLs) and biofuels) grew at an average rate of 1.2 per cent per annum, the volume of crude oil transported by tankers grew by just 0.9 per cent but seaborne crude trade in tonne-miles grew by approximately 2.5 per cent.

This lengthening of average sailing distance (average haul) of crude oil cargoes, from an estimated 4,500 miles to 5,300 miles, was driven by significant shifts in the sources of demand and supply growth. Over the last decade, the rising tide of Asian (particularly Chinese) crude demand pulled a growing proportion of crude tankers eastwards. This was partially met through increased supply from the Middle East, which applied downward pressure on the average haul. However, these volumes did not meet all of Asia's demand growth, and crude imports from further afield also grew. The key catalyst in lifting the average haul was the shale revolution in the US—this displaced short-haul crude imports from Central and South America, which were diverted to Asia and then, from 2016 onwards, joined by exports direct from the US.

As with crude, trade in oil products is a function of multiple dynamics—domestic supply–demand mismatches, local refinery capacity/configuration, crude composition, global price differentials, transport cost, storage availability and, of course, geopolitics. Given the assortment of oil products, the trade is more complex than that of crude and it is thus difficult to describe in aggregate, but some large-scale trends can be highlighted.

Traditionally, refineries were built close to centres of end-user consumption, primarily due to cost (crude is more economical to transport than oil products). Thus, historically, oil products have been shipped less frequently and over shorter distances than crude. One side of this picture is changing though: between 2009 and 2019, while the estimated average haul remained reasonably steady at roughly 2,900 miles, the volume carried by products tankers grew by 2.3 per cent per annum—higher than the growth rate of crude production (1.2 per cent), refinery throughput (1.3 per cent), or end-user demand (1.6 per cent).

This uplift in oil products trade reflects the same forces that influenced crude flows. Asia's growing demand for crude was driven by refinery additions—principally in China and India—which (partially) met growing local demand through increased intra-regional trade. Concurrently, the energy revolution in the US funnelled cheap feedstock into its refining sector, transforming the country into a net exporter of oil products from 2011 onwards. Some of these exports were absorbed by Asia's internal shortfall, others were directed to closer markets. Refinery capacity in the Middle East also grew—boosting both intra-regional and inter-regional (into Europe, Africa, and Asia) trade.

So, over the last decade, as growth in refinery capacity and oil demand migrated eastwards, demand for crude and products tankers was supported, respectively, by lengthier and larger trading. What will happen in the coming decade? Precisely how oil demand will recover and then grow post pandemic is uncertain, but some trends can be discerned. One widespread expectation is that demand growth will rest squarely on the shoulders of the petrochemical sector; another is that demand for oil in Asia will continue to grow. The timescale over which (and even the degree to which) demand for transport fuels will recover is more keenly debated, as is the question of whether the pandemic will hasten the arrival of peak oil.

Despite the global contraction in refining activity over the last year, capacity is set to grow (predominantly East of Suez). The IEA's recently released medium-term oil outlook projects that Asia will account for more than half of refinery additions and expansions by 2026, driving crude demand to 26.6 mb/d (3.5 mb/d above 2019 levels). The Middle East currently sends approximately 85 per cent of its crude exports to Asia, equating to roughly 60 per cent of Asia's total crude imports. As global oil production rebounds in response to demand recovery, the Middle East could supply up to three quarters of Asia's crude demand, acting as a brake on the rising average haul. So, although imports from the Atlantic Basin will also grow, the growth in crude tonne-miles should mirror that of tonnes.



The outlook for transport fuels—key cargoes for products tankers—is uncertain, but continued growth in Asia is expected. Despite the expansion in Asian refining capacity, the IEA projects that demand pressure will result in a refined products deficit, necessitating growing imports into the region. Much of this additional supply will come from the Middle East (which will account for a third of global refinery expansions between now and 2026—part of the region’s concerted effort to capture greater value from export-oriented refining activity). Not only will this raise the average haul, it will also increase inefficiency in the products tanker fleet: such discrete longer-haul trades are more likely to be round voyages (in other words, tankers will spend half the time ballasting) compared with intra-regional trading, which offers greater opportunity for triangulated voyages. So, in contrast to crude trade, even with increased short-haul intra-Asian trade, the average haul for oil products should rise over this decade, acting as a multiplier on products tanker demand.

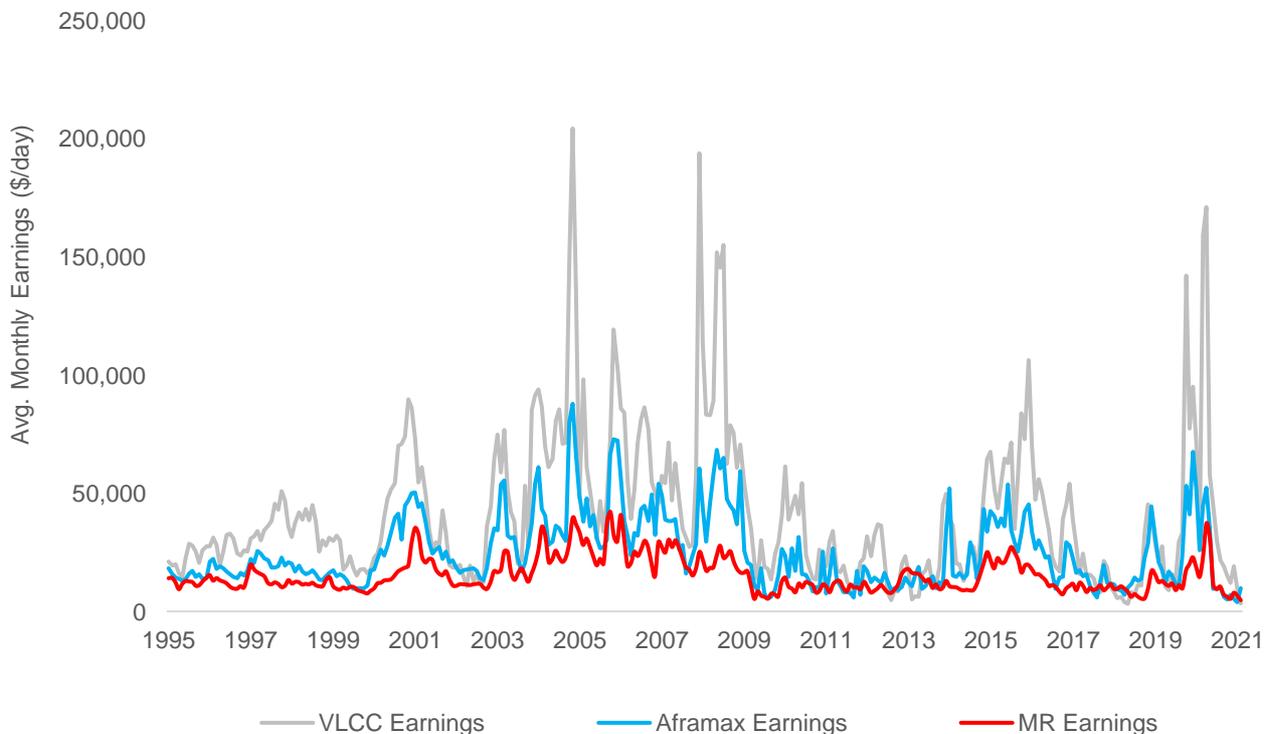
While demand growth for traditional refined oil products will shift eastwards, incremental demand for feedstocks by the petrochemical industry will be more evenly distributed across the globe and will result in increased movement of NGLs, LPG, ethane, and naphtha. However, only naphtha is transported in products tankers (as opposed to gas carriers) and, once again, Asia will be the centre of demand growth for this feedstock. Sources of supply will be determined by future global refining margins, but given the degree of growth, it is also likely to be positive for average hauls.

Therefore, over the coming decade, as Asia retains its role as the epicentre of oil demand growth, and as increasing volumes of crude and oil products transit into and around the region, the demand growth for products tankers could move ahead of that for crude tankers. How might this then influence the relative returns on investment in crude and products tankers?

Riding the waves of tanker earnings

It has often been noted that, seemingly regardless of the differing supply–demand dynamics of each sector, the charter rates earned by crude and products tankers tend to move in sync (though typically, the larger the ship, the more volatile the earnings). This can be seen from the average monthly earnings of VLCC (capacity ~2 million barrels) and Aframax (capacity ~0.8 million barrels) crude tankers and MR (capacity ~0.3 million barrels) products tankers over the last 25 years.

Average monthly earnings (\$/day) for VLCC and Aframax crude and MR products tankers



Source: Clarksons Research Services

At an aggregate level, a similar pattern evolved in both crude and products tanker fleets. Over the first half of this 25-year period, growth in tanker supply (fleet capacity) and demand (tonne-miles) were evenly matched in both sectors, and the



frequent upswings in earnings typically reflected short-term (and often regional) supply–demand imbalances. However, the heated market through the 2000s instigated a new building spree, and the orderbook grew to record levels (peaking at 47 per cent and 64 per cent in 2007/2008 for crude and products tankers respectively). From 2009 to 2019, crude tanker fleet capacity grew at 3.5 per cent per annum (versus 2.5 per cent growth in crude tonne-miles) while products tanker fleet capacity grew at 4.8 per cent per annum (versus 2.2 per cent growth in oil products tonne-miles). This overhang in tanker capacity has meant that, over the last decade, earnings spikes have only been caused by larger-scale (and often global) events—and such events did not necessarily affect the crude and products fleets in the same way.

Falling oil prices in 2015 led to contango-based floating storage demand for crude tankers while, for products tankers, the concurrent uplift in rates was stimulated by a steep rise in refinery throughput in Asia and Europe (although use of some larger products tankers for storage plays was also reported). At the end of 2019 there was a short spike in crude tanker rates driven by increased refining of low sulphur bunkers ahead of the IMO 2020 sulphur cap, but products tankers witnessed only a marginal rise in rates. The most recent peak, in spring 2020, was again due to demand for crude and oil products floating storage—though this time out of necessity rather than exploitation of arbitrage opportunities.

Outsiders typically interpret the state of tanker markets through the fluctuations of VLCC charter rates, but tanker owners have a greater interest in the longer-term earnings potential of their long-lived assets. The chart below plots, on a monthly basis, indicative annualized returns for VLCC and Aframax crude and MR products tankers, calculated over a five-year holding period (using five- and ten-year old tanker price timeseries), with income estimated from average monthly earnings and average OPEX as reported by the industry. Thus, the return in January 2021 reflects an acquisition of a five year old tanker in January 2016, against which the net income over the five-year holding period and the gain or loss on the sale of the ten year old tanker in January 2021, is assessed (and annualized).

The below should not be interpreted as actual returns realized by tanker owners. These will be determined by a host of factors, the most important of which will be the timing of vessel acquisitions/disposals and decisions around employment. Tonnage providers (shipowners who do not typically operate cargo contracts) generally either commit their tankers on term charters, whether for a few months or several years, or place their vessels in pools controlled by operators. On the other hand, entities such as trading houses which control cargoes as well as tankers (sometimes through direct ownership, but more usually by chartering in from tonnage providers) can earn significant premiums by arbitraging differentials between spot and term charter rates, and by reducing ballast legs.

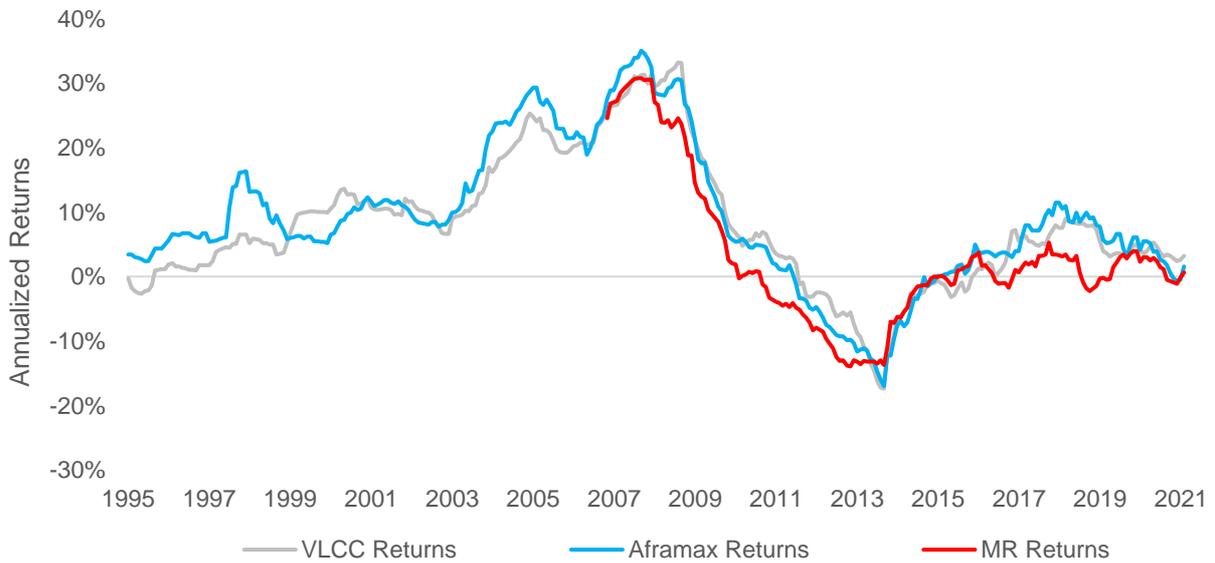
That said, however, the above exercise does allow for a reasonable comparison of indicative returns across each ship type. Despite the obvious volatility in earnings, the coincidence of returns across all three tanker types is intriguing, indicating that tanker owners have earned only a slight premium for the earnings volatility associated with larger ship types. The disconnect seen in recent years between both types of crude tanker and the products tanker is also interesting: over the last five years, owning MR tankers has seemed like a (comparatively) poor investment. Separating the earnings yield and capital change components of return, the underperformance is primarily down to the former. In commoditized shipping markets such as tankers, second-hand vessel prices generally reflect short-term earnings potential and so rates and prices tend to move (roughly) in unison. The relative underperformance in MR earnings indicates that second-hand MR tanker prices have not responded to rate movements to the same degree as seen in the crude tankers. Is this a blip, or an indication that the disconnect between the earnings (and thus asset prices and therefore, by extension, returns) of crude and products tankers will grow in future?

Will crude and products tankers sail side by side towards the horizon?

Both tanker sectors have spent more than a decade riding a super cycle wave of supply, where the potential for healthy earnings rested on largely unforeseen events. However, pre-pandemic, fleet growth was already dwindling; at the end of 2020, the crude and products tanker orderbook stood at 25-year lows of 9 per cent and 7 per cent of fleet capacity respectively. Ordering is likely to remain subdued given the uncertainty that tanker owners face on multiple fronts across a span of timeframes: the rate and degree of recovery of the oil markets post-pandemic; changing vessel designs to meet future emissions reductions targets; the long-term outlook for oil cargoes; and the adaptability of existing tankers to carry new fuels.



Annualized total returns over a five-year holding period for VLCC and Aframax crude and MR products tankers (MR tanker returns from Nov 2006 onwards due to availability of price data)



Source: Marine Capital, Clarksons Research Services, Moore Stephens

With floating storage having unwound during the latter half of 2020, the market for both crude and products tankers remains depressed and any recovery rests on a rebound in oil demand. Over the medium term, the rising tide of demand in Asia will support growing volumes of both crude and oil products trade, but only the latter is likely to see an additional boost from increasing average haul. As a result, products tankers could begin to outperform crude tankers. However, while future events that favour one sector over the other could disrupt the historical cointegration of crude and products tanker earnings over a short period, given that supply fundamentals in both sectors are still running in parallel, it is unlikely that the relationship will be completely severed over the medium term.

The long term, however, is a different kettle of fish. Whether demand for oil-based transport fuels peaks at the end of this decade or well into the next, traditional refinery economics will come under increasing pressure. Refiners will need to adapt to survive—be this through petrochemical integration, biofuel specialization, or hydrogen production. Similarly, tanker owners will need to formulate strategies to capture the best opportunities as the future fuel mix evolves.



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