



A QUARTERLY JOURNAL FOR DEBATING ENERGY ISSUES AND POLICIES

This issue of the Oxford Energy Forum is devoted to analysing the role of oil benchmarks, their evolution over time, the challenges facing the most established benchmarks, and the extent to which the current transformations in oil market fundamentals and crude trade flows as well as changes in the regulatory environment are likely to result in the emergence of new benchmarks and new crude oil pricing systems.

The issue opens with an article by *Jorge Montepeque* who reflects on some fundamental questions regarding benchmarks. He notes that despite the many moving parts in the oil market, the reality remains that nothing of significance has happened recently with existing benchmarks. There have been some changes, but these remain marginal. He argues that markets and their rules emerge in a natural way; at early stages, markets are fragmented and without clear standards, but over time, buyers and sellers agree on issues such as measurement, storage protocols, and payment methods. It is the market that drives the standardization process, and this explains why efforts by external actors, such as governments or regulators, to establish new systems face delays or

end up not being adopted by the market. Once benchmarks have emerged from this natural process, only one will usually assume the status of the true representative of value in its market. Brent has achieved this status, but questions about its relevance and future status persist as production continues to decline. For the West Texas Intermediate (WTI) benchmark, the real problem is location, as the price at Cushing is no longer relevant. These and other problems can be solved if enough people have a clear objective and purpose and are willing to take decisive action. However, a hands-off approach seems to prevail at the moment, as is typical of any business where core products are generating large margins. Even if the product is in need of major revamping, the common approach is not to do anything radical. According to Montepeque, companies mature, much like people do, and then the objective becomes self-preservation rather than creative destruction. It is the new entrants and disruptors that are willing to engage in creative destruction; many will fail, as the incumbents are strong, but eventually one or more will succeed. The author concludes that Brent has a volume problem while WTI has a location problem, and this can

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provide opportunities to outsiders if the custodians of these two markets are slow in solving existing problems.

Peter Caddy explores continuity and change in the long history of oil benchmark development and oil price reporting. He argues that the work of price reporting agencies (PRAs) is frequently misunderstood – that PRAs are perceived to design a contract or a methodology and then present it to market participants for them to adopt or not, when in reality, parties conduct deals in specific ways and PRAs have to follow and adapt to the realities of the market. The author emphasizes the importance of differentials in trading crude: while the futures market has become the discovery point for the absolute price, the differentials around this pricing point are central to pricing crude and products. PRAs' main role is to price differentials and therefore PRAs and futures exchanges tend to complement each other. But the feasibility of what can be reported is also important, and feasibility tends to change over time. PRAs' methodology and work should be culturally accepted; and although more regulation has meant fewer legal threats, it has also had the unintended consequence of companies' reluctance to report, not because it is illegal, but to avoid the inconvenience of having to explain their actions to the wider society. Caddy concludes by arguing that regulation nowadays places more emphasis on process than accuracy, and that this, in addition to the recent increase in US shale production, makes it likely that US benchmarks and pricing methodologies will only increase in importance.

Evelien Van Den Arend and *Payal Lakhani* review the recent drive towards greater regulation of benchmarks, particularly in Europe. The article looks at the reasons benchmarks found themselves under such scrutiny and the

remedies that the regulators have established to address public concerns. The authors summarize the requirements that European benchmark regulation places upon the design and maintenance of benchmarks and the consequences of the new guidelines. The rules seek to enhance the robustness of benchmarks by introducing new governance and oversight requirements as well as providing guidance on the design and review of methodologies. The legislation has been broadly accepted by the energy industry, despite concerns that its requirements may prove a barrier to entry for new PRAs or may deter energy firms from interacting with PRAs.

The Forum then discusses the three key international benchmarks – Brent, WTI, and Dubai – and their potential challengers: Argus WTI Houston, the Dubai Mercantile Exchange (DME) Oman, China's recently launched International Energy Exchange (INE) crude oil contract, and the Saint Petersburg International Mercantile Exchange (SPIMEX) Urals contract.

Colin Bryce reviews the historical evolution of the Brent market and the various challenges it has encountered since its inception. He argues that despite the many changes to the benchmark, Brent has demonstrated a remarkable resilience and continues to grow. This, however, has come with increased complexity, mainly as the consequence of incremental tactical changes. The author argues that Brent may now be at the threshold of another challenge, which may require moving beyond tactical solutions to more strategic changes, including the possibility of bringing Urals into the assessment and/or changing the benchmark from an FOB (free on board) to CIF (cost, insurance, and freight) basis. These changes are not without their own problems and

challenges and will add more layers of complexity; but, as in the past, Brent is likely to continue to adapt and to attract liquidity.

Liz Bossley believes that work is needed to repair Brent, given its poor physical liquidity and the need for a more comprehensive value adjustment mechanism for quality premia. Bossley nonetheless argues that the oil industry needs multiple key price reference points. She distinguishes between a price referencing point and a benchmark. A key prerequisite for a grade to become a benchmark is that it is expressed as a fixed and flat number. In most active benchmarks, liquid trading emerges mainly in forward and futures contracts and swaps. In contrast, PRAs tend to identify the price differential in relation to the benchmark. She argues that WTI Houston is still a price referencing point and not a benchmark and that, while it has many of the important characteristics of a benchmark, it still faces a few hurdles, including logistical factors; and she advises supporters of WTI Houston to consider whether the US, whose president considers that 'trade wars are good,' constitutes a benign environment. Bossley concludes that significant effort will be required for Brent to evolve and for WTI Houston to emerge as a benchmark. Rather than behaving as if the success of one will come at the expense of the other, all interested parties should work together for both to succeed in order to promote more efficient benchmarks.

If Brent is suffering from lower physical production, *Dan Brusstar* argues that the opposite is true of WTI, which is benefiting from the US shale revolution and soaring US production figures. Brusstar notes that WTI has faced difficulties in the past but that each time it has come back stronger. The article suggests that WTI is enjoying a renaissance in the global



marketplace, as the US ramps up oil production and becomes a major exporter of oil. Brusstar argues that with the remarkable growth in US exports, particularly to the Asian markets, the WTI futures benchmark has once again become the key pricing and hedging tool for the global marketplace.

James Gooder also considers the implications of the lifting of the US crude export ban on WTI and pricing mechanisms in the US. Since early 2009, the Cushing (Oklahoma) hub, the home of the WTI futures contract, has suffered from periods of supply glut, which caused a wide divergence between WTI and Brent prices. This pushed some Gulf exporters such as Saudi Arabia and Iraq to adopt the Argus Sour Crude Index as a benchmark for their crude exports to the US. As US shale production continued to increase and as new infrastructure was built to move new production to the Gulf Coast, a spot market for WTI emerged in Houston, with trading volumes there increasing sharply and a wide range of players participating in spot trading. According to the author, this has supported Argus WTI Houston price assessment and resulted in a sharp rise in derivatives trading activity around WTI Houston as traders rushed to hedge the basis risk. Gooder argues that WTI Houston has evolved to become the best indicator of price at the US Gulf Coast and that the next step in its evolution is to incorporate it into existing relationships. After all, according to the author, exporters to the US compete with WTI at Houston and not in Cushing or Midland (Texas), and therefore spreads such as WTI Houston–Brent or WTI Houston–Dubai are more appropriate to reflect the available arbitrage opportunities.

Dave Ernsberger discusses the transformation of the Dubai benchmark

through a variety of innovations, including the addition of new grades and new delivery mechanisms that ensure it remains fit for purpose. He argues that the importance of the Dubai benchmark lies in the fact that it generates a clear, flat-price spot market for Middle East medium sour crude as well as a forward curve for both physical and derivatives markets. It also serves as the cornerstone to the two most important spreads: paired with Brent and sometimes with WTI, the differential between these crudes underwrites the flow of crude between the Atlantic and Pacific basins. The same spreads also reflect sweet/sour crude economics, which can have a major impact on how refineries plan the purchase of their crude. Ernsberger argues that the fact that more than 2,000 partial cargos trade during the Platts Market-on-Close every year, the broad participation in trading activity, and the increasing volumes in Dubai-settled futures and other exchange-cleared derivatives are a testament to the participants' confidence in the Dubai benchmark.

Tilak Doshi raises the question of whether there is a viable alternative to the Dubai benchmark for pricing Gulf crude to Asia. The three potential alternatives are the Oman futures contract traded on the DME; ESPO (East Siberia–Pacific Ocean) crude spot sales off the port of Kozmino, Russia; and the sour crude futures contract launched recently by the Shanghai INE. He argues that the Oman futures contract acts more as a tool for delivery of Omani crude and that DME's ambitions for the contract to act as a pricing benchmark and a key market for risk management have not been fulfilled so far. ESPO faces multiple challenges, such as market concentration and the stability of crude oil quality, which are likely to prevent it from emerging as a benchmark, and therefore, ESPO will most likely

continue to trade as a differential to Dubai. INE's crude oil futures contract also faces multiple challenges, the most important of which is the government's reluctance to allow commodity markets to trade freely and openly. The author concludes by arguing that pricing benchmarks are the outcome of market evolution and not the result of government push, and that Dubai has shown remarkable resilience, in large part due to its links with the Brent market through the Brent–Dubai Exchange of Futures for Swaps, which allows market participants to manage their risks through one of the most actively traded derivative oil contracts.

Paul Young sees change afoot in the Middle East. He notes that national oil companies in the region are adapting their marketing strategies and refocusing their marketing departments into fully fledged trading companies, a key step in the region's development as a trading and benchmarking hub – and that despite the increase in US shale production, the Middle East is likely to remain the crude oil kingpin. He argues that Oman is the single most important grade in the Middle East when it comes to price discovery, in terms of both its futures contract and its key role in the Dubai pricing mechanism. Looking forward, it is also expected to play an integral role in the INE crude futures contract. Oman remains the largest freely traded crude stream in the region; it is popular amongst Asian refineries; and DME Oman has established itself as the largest physical commodity of any commodities contract. Another innovation has been the DME auction platform, which according to the author has brought a new level of transparency. Another important development has been the expansion of refining capacity and products trading in the region. This may induce a change in behaviour, and rather than managing prices against



netback models, the industry may rally around new and more relevant benchmark pricing.

The Shanghai INE's new crude futures contract is the subject of the next three articles. *Michal Meidan* argues that the Shanghai contract is part of China's natural progression from price taker to price maker in global oil markets. But the contract faces a number of challenges to its wide adoption by foreign traders. One concern is the choice of crudes, given that grades from China's largest suppliers – Russia, Saudi Arabia, and Angola – are not represented in the contract. An additional concern for foreign traders and independent refineries looking to deliver into the contract is storage space, given that tanks are owned and operated by Chinese majors. The currency question is another concern for foreign traders, as Beijing is seeking to encourage greater use of the yuan renminbi (RMB) in cross-border trade. *Maiden* argues that if the INE futures contract is liquid and transparent enough, then pricing large volumes of oil in RMB will impact global markets. But she thinks that this is still some way off and would need to happen along with international banks holding more RMB reserves and producer countries showing willingness to source more goods from China. The government's currency controls and intervention in the stock market will likely act as a deterrent. The author concludes by predicting that in the first months of trading, all eyes will be on Chinese retail investors, who are likely to drive the market, and there are some fears that they may overheat it. But over time, the INE is likely to fine-tune the contract to encourage more refineries and traders to participate.

Tracey Liao, Edward Morse, and Anthony Yuen also analyse the prospects of INE's crude oil futures contract, arguing that some Chinese

authorities believe that establishing such a contract could eliminate the 'Asian premium' and could result in more transparent and robust price discovery for medium sour crude. Another objective is to expand the internationalization of RMB and encourage participation in China's financial and commodities markets. The authors predict that while its domestic success is almost certain, a number of mostly made-in-China issues will likely impede its international success, with foreign participants most likely taking a wait-and-see approach. As in the previous article, the authors see domestic speculators providing tremendous liquidity, but this could be potentially bring destabilizing volatility and manipulation, which could endanger the integrity of the contract. The authors argue that the Dalian iron ore contract could serve as a good precedent for the INE's crude futures contract, despite some important differences (for instance, China accounts for 70 per cent of global seaborne iron ore imports but only 10 per cent of the world's oil demand). Daily trading volumes of Dalian iron ore suffer from substantial speculative retail flows and dislocations between prices of contracts upon settlement and actively traded contracts. The authors conclude by arguing that although the INE futures contract seems to superficially satisfy most criteria required for a successful benchmark, the broad acceptance criterion remains an exception.

Antonio Merino and Roddy Graham also examine the prospects of INE's crude oil futures contract, arguing that for the contract to be successful, it should satisfy three criteria: it should fulfil a commercial need for hedging; it should succeed in attracting a pool of speculators; and public policy should be supportive. The authors believe that, while the new contract satisfies most of these criteria, more work needs to be

done to ensure its success. One particular problem relates to physical delivery against the futures contract, where the delivery mechanism entails significant risks for foreign sellers and producers while Chinese buyers/refineries tend to capture most of the benefits. The current design of the contract suggests that physical trading will occur mainly between Chinese state-owned oil companies and local teapot refineries. The authors argue that the risks need to be more evenly spread between buyers and sellers for the contract to become a truly regional benchmark.

Another potential contender is the physically settled Urals crude futures contract on the Saint Petersburg International Mercantile Exchange (SPIMEX). *Alexei Rybnikov* predicts that the sufficiently large, freely tradable volumes of Urals alongside an open, transparent, and well-regulated futures market will eventually result in the market's acceptance of Urals as a superior benchmark to existing ones. According to the author, Baltic oil remains the most appropriate choice for a reference pricing point to the two other main export routes of Russian crude oil, Kozmino and the Black Sea, given the destination flexibility that Baltic oil enjoys relative to other Russian crude exports. The key advantage of the Baltic oil acting as a benchmark is that it allows producers to manage their risks and identify arbitrage opportunities when open. The author notes that the volume of Baltic deliveries of Urals is twice that of the Brent complex and the scale and scope of the supply and consumption of Urals is larger than those of any other single crude oil stream in northwest Europe. SPIMEX is still working to solve complex issues, but *Rybnikov* believes that eventually, the futures contract will emerge as the appropriate and rational choice for much-needed improvement in the current oil pricing systems.



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OIL BENCHMARKS: ARE THEY TOO CRUDE FOR THE FUTURE?

Jorge Montepeque

Some questions never die. Are benchmarks fit for purpose? Are the markets working well? Is there sufficient underlying production? Can the benchmarks cope with production outages, pipeline leaks, or port shut-ins due to bad weather? Are the Europeans or Americans better positioned for the long haul? Do the Russians have a chance? Will the Chinese futures take over? . . . The list goes on.

There are also newer questions. Is the new American crude the right kind of crude, or is it too light? Is this light gravity good or bad for a benchmark?

Exciting times, one would say, because there are so many questions and so many moving parts. At the same time, nothing significant has happened with the existing benchmarks. There have only been marginal changes in a world that is changing very fast. The USA is a major exporter, North Sea infrastructure and deliverability have been tested, China has become the largest oil importer, and tension with Russia has actually increased.

But let's look at the underlying need for benchmarks, their characteristics, and how the various generators of benchmarks are coping with change – or not.

What the market needs from a benchmark

Organized markets spring up naturally any time a sufficient number of buyers and sellers need to find each other frequently and reliably. Initially, they are extremely fragmented and without standards; but over time, buyers and sellers agree on measurements, storage protocols, contractual

language, methods of payment, currency, and a myriad of other details. The process is the same whether the market is grain, cattle, metals, coal, or oil. Market needs drive and shape the standardization process, conferring an imprimatur of genuineness that an outsider could never bring. This is one reason that market creation driven by an outsider such as an exchange or government can be delayed or rejected. An exchange or publisher can mirror, modify, or even leverage existing practices, but a core practice needs to exist with commercially driven players.

As a market is created, the need arises to exchange goods within or near the market price. Managers, overseers, and individual traders need an outsider, preferably a transparent and creditworthy entity, to provide a price that can work as a barometer of value – that is, a benchmark. Of course, both sellers and buyers would like to beat such a benchmark.

Once a benchmark starts to get established, several key characteristics and behaviours emerge, including seniority – only one benchmark will be seen as the true representation of value in its market – and the inevitable pushback. Some participants may complain, sometimes even passionately, about the accuracy of the benchmark; but their comments (if the benchmark designer is listening) help build and shape a stronger benchmark.

The need to be aligned with a number widely recognized as representing market value will lead to transactions that are benchmark linked. At this point, the benchmark is on the road to seniority – but the adoption is not guaranteed, as surely others will also claim to represent that value.

In the crude market, there have been three main benchmarks: Dubai for mid sour oil and Middle Eastern supplies, West Texas Intermediate (WTI) for the

Americas, and Dated Brent for the world.

The struggle for acceptance and relevance is unending, but most would agree that the greatest number of term and spot barrels are linked to Dated Brent. This achievement took many years of hard work, innovative design stemming from a deep understanding of market mechanics, and, one could say, selling of the concept, as Dated Brent's inner workings are not easy to master.

But the deep struggle is about relevance, as the long-term production decline in the fields sustaining Dated Brent triggers an uncomfortable question about what is next.

Dated Brent enjoys the benefits of incumbency, which are supported by multi-year contracts in crude and even liquid natural gas with a daily sprinkle of spot deals. These contracts are multiregional, involving Europe, Russia, Africa, and even the eastern American coast.

But hardly any large industry gathering occurs without someone asking, 'Is the benchmark suitable for the long haul?'

Problems are solved if enough people have a clear objective and purpose. Most problems require some thought followed by clear and decisive action. But this is only possible if there is first a clear acknowledgment of the problem and a clear purpose. In the case of Dated Brent, is the primary purpose an unimpeachably accurate assessment, an easily accessible tradable instrument, or tradable volume? Can these objectives be married?

These are the kinds of questions the assessors and exchanges need to clarify as the challenges stemming from the ageing of the system become more evident and perhaps more frequent. As an example, the market was concerned about stability in the North Sea



benchmark following the leak in the Forties pipeline in mid-December 2017. Interruptions in deliveries are a serious issue, but the system was designed to provide alternative delivery options. This means that if one strips down to the core issue, there wasn't one. Back in the day, one concern we had was the possibility that a weather or geological event could simultaneously shut down all the loading platforms that sustain Dated Brent. We rapidly concluded this was not a likely scenario for the North Sea but could occur only in the US Gulf Coast. A bad hurricane could disrupt loadings simultaneously in Texas and Louisiana.

Volume is an issue for the North Sea benchmark, and significant additions come in with quality degradation or with heavy political issues, which appear not to be improving yet. Political realities must be considered, as the inherent and unimpeded ability to trade the volumes sustaining the benchmarks is critical.

This brings the focus on Urals as alternative delivery; and while it freely trades, one could see the worried look if world crude pricing were to be set at the margin by a Russian grade. At this time, however, underlying tensions make it unlikely that the Saint Petersburg Mercantile Exchange's

marketing efforts will bear fruit for some time.

Meanwhile, US production is soaring, and forecasts call for even greater output. As earlier noted, volume matters, and the significance of the US benchmark is likely to grow. The USA is expected to become the largest world oil producer later this year. In its latest report, the US Energy Information Administration forecast US production to average 10.7 million b/d in 2018 and 11.3 million b/d in 2019.

US and Canadian production is typically hedged using the CME Group (CME)'s light crude oil futures benchmark. Volumes at the exchange therefore naturally grow as North American output expands. Another pricing issue with benchmarks is whether they have full connectivity with the physical market. Because the CME futures contract is physically delivered at Cushing, Oklahoma, there should be no disagreement on this issue.

But the real problem is location. The price at Cushing is not very relevant to the world at large. An international player looking at the US benchmark price needs to add the freight and other fees needed to move the oil from Cushing to the US Gulf to determine its actual value. Based on historical data,

this correction ranges from a few dollars to almost \$20.00 per barrel, depending on market circumstances. The Brent (FOB North Sea) to WTI (Cushing, Oklahoma) spread has been as wide as \$25.00 per barrel.

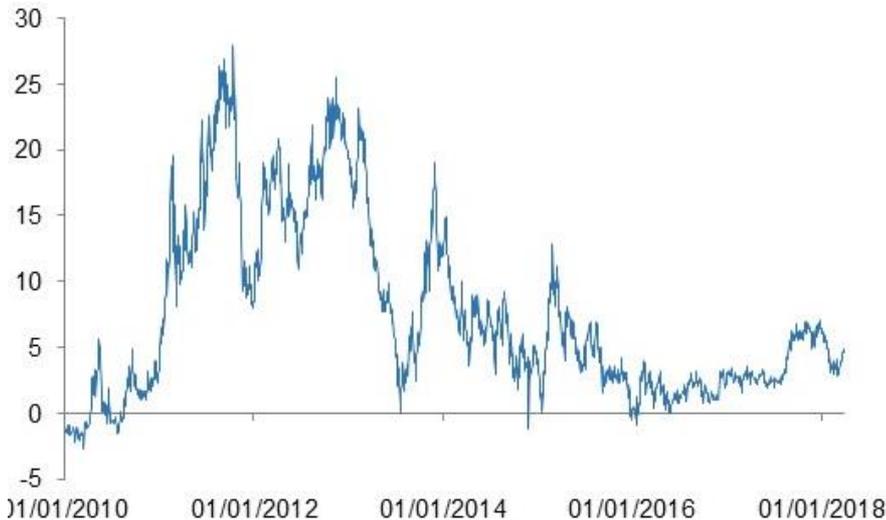
Furthermore, as US production expands, there is a likelihood that pipelines or terminals may not be fully in step with market needs. This will inevitably result in an accordion-type effect in the commonly followed Brent-to-WTI spread. This in turn raises issues as to which of the two benchmarks is the true representation of value, as in theory the two crude oils, being similar, should in an ideal world be separated by the international freight.

But as Yogi Berra unforgettably said, 'In theory there is no difference between theory and practice. In practice there is.'

The graph shows the difference in prices between the front-month futures Brent and WTI contracts. One could say that the spread should reflect the arbitrage between the two markets. But this is not even remotely the case: any arbitrage impression would be wrong, as the data are overwhelmed by the cost of freight between Cushing and the US Gulf Coast (primarily Houston). The spread seems to largely measure the arbitrage between Cushing and Houston.

To the casual observer, the data suggest that the CME futures contract is in the wrong location because, when the spread between the two markets hit \$25.00 per barrel, the contract was correctly reading the values in Cushing, while the arbitrageurs needed to measure the prices in the US Gulf versus the international market. This resulted in many refiners on the US east coast bolting away from the CME and using Brent for their crude imports.

Brent-WTI Spread, US\$/Barrel





Prospects for location resets: low to non-existent

The long-term commercial success of the CME/New York Mercantile Exchange light sweet crude oil contract has embedded the systems firmly in Cushing. The long-term growth and natural profitability and margins in the contract understandably discourage change. Informally, comments made by individuals associated with the exchange can be summed up as ‘If the contract isn’t broken, why fix it?’ Moreover, they point to the healthy volume growth. And who can argue with success?

This type of hands-off approach to a successful product is typical of any business where the core product is generating large margins. Even if the product looks a bit frayed at the edges, the common approach is not to do anything radical. Companies mature as individuals do, from aggressive growth and expansion to wealth and status preservation. It is almost like we all are bound to become sloths in our old age.

Senior personnel at the two large competing exchanges have stated that

for a business to remain successful in the long term, some amount of creative destruction is necessary. But this seems to be largely reserved for new entrants and disruptors, rather than a proposal an established business could sensibly make to its board of directors. Putting a business on the line is not something business managers like to do. In other words, rapid or radical change by established publishers or exchanges is unlikely regardless of the market’s needs.

In the short to mid term, the CME seems to be gaining ground, not because of any specific policy but based on US production growth.

Before 2014, crude oil volume traded on the Intercontinental Exchange (ICE) seemed poised to overtake that of the CME. The volume growth coincidentally occurred when the spread between WTI and Brent was at the widest. But by 2016, the process had reversed and the CME crude contract was undeniably gaining ground versus the ICE crude contract. Arguably, the different rates of growth at both exchanges would be a natural reaction

to the long-term contraction in North Sea production and long-term growth in US production.

Brent’s primary stress is production shrinkage, and WTI’s location, but no earth-shattering action by either side is expected any time soon.

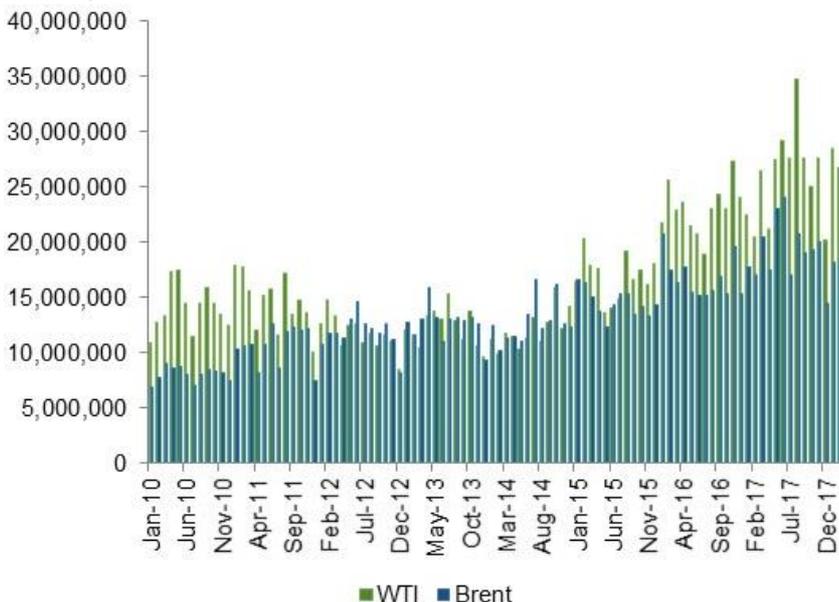
And here come the disruptors!

Life is full of change and surprises, but disruption in an entrenched business typically comes from the outside. Many disruptors try and fail, as the incumbents are strong – until a disruptor hits the mark!

Exchange efforts in Russia and the Middle East have so far not made a dent in established practices or attracted significant volumes. Volumes at the Dubai Mercantile Exchange are growing but arguably still disappointing. Recently, the Shanghai International Energy Exchange launched its delivered crude oil contract after many years of waiting and marketing. Analysts had expected the exchange to face no troubles with domestic support and liquidity; the big question was participation by foreign entities. Among the many issues facing non-Chinese traders is the currency exposure to the yuan. Undeterred by such concerns, foreign companies, including traders and majors, are reported to have jumped in with gusto. The crude contract is the first that foreigners can buy and sell. About 21 million barrels traded on the first day, according to public reports, and more importantly, Shell sold a crude cargo to China’s Unipec linked to the exchange.

Chinese participants are very optimistic; one recently said that within two years a significant portion of imports will be based on the new index. They are also hopeful that this is a step toward globalization of the yuan. Who knows, really? But the will, the long-term commitment, and the size are there.

Monthly traded contracts, CME/WTI vs. ICE/Brent (each contract = 1000 barrels)





There is a push for prominence for China on many fronts, as the economy grows and exerts its influence not only regionally but globally. China has become the largest crude oil importer after the USA, while the USA is on its way to becoming the largest producer. One could almost see the face-off between FOB (free on board) and CIF (cost, insurance, and freight) indices. Both the US and the North Sea benchmarks are FOB.

But openings remain elsewhere. Brent has a volume problem, while WTI has a location issue. Problems for the two incumbents can be opportunities for outsiders if the pace of change by the custodians of those two markets is too slow.

Some market participants have gone as far as saying that the answer for both contracts is to reset them into delivered contracts in areas where there is a refining market, such as Houston and Rotterdam. The issues created by a relocation of a contract are huge, due to the technicalities of moving open interest from one basis to another. Would it be very difficult? Yes, of course. But is it impossible? No. All that change needs is hard work and a thick skin.

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BENCHMARK DEVELOPMENT: LOOKING BACK AND FORWARD

Peter Caddy

Oil price reporting and benchmark development have undergone major changes over the last generation, while experiencing continuity in other respects. Based on these changes and continuities, it is possible to project likely future trends.

What has remained the same?

The one constant is that very few people understand what a price reporting service does, how it provides

added value, and how it adds to the efficiency of the market to the benefit of both buyers and sellers. It is often a shock to executives in the oil industry when they realize just how much money their companies will lose if they cannot access and utilize reported prices of the physical markets that their own companies trade. Similarly, price reporters are continuously told, by people who have never reported a market, how they can report prices more accurately. Sometimes the advice may appear theoretically attractive – and we all know the idealized requirements of a physical oil market benchmark are lots of sellers, lots of buyers, a standardized contract, high transparency, and good levels of liquidity. But for those of us who live in the real world, the three constants of benchmark provision have been, are, and will continue to be: Is the reporting methodology feasible? Is it sustainable? And is it culturally acceptable?

These concepts are difficult to understand, not least by policymakers. There is usually an underlying assumption that price reporters design a contract, or construct a reporting methodology, and then the industry chooses, or doesn't choose, to trade on that basis. In other words, the process is similar to an exchange designing a futures contract. The reality is that companies conclude bilateral deals on terms and conditions that, for convenience, may be reflected in standard, or similar, contracts. Sometimes a price reporting service may influence the nature of these terms by only using one type of contract to identify market price. But if the buyer and seller choose to sign on different terms, eventually the reporting service will have to adapt to the realities of the market.

Firstly, feasibility requires a realistic assessment of real-world constraints

and opportunities. For example, the first draft of the European Union's Benchmark Regulation would have effectively prevented reporting and use of any crude oil price series in the European Union because the civil servants had no idea what was and was not feasible. They were not aware that crude oil in the North Sea is traded in large seagoing vessels and therefore the number of transactions in the physical market is limited – unlike trade along a pipeline, which can be divided into much smaller parcels. Similarly, North Sea terminals can only load at a certain rate, so the number of traded cargoes is limited by the infrastructure of the terminal. Thus, price identification based exclusively on transactions, in a seaborne cargo market, is not feasible or at least would not be consistent. This is not the same as saying price reporting and benchmark construction for North Sea crude is not possible. It is just not sensible for it to be solely based on transactions.

The final iteration of the European Benchmark Regulation acknowledges this and allows for methodological flexibility in price identification and benchmark construction. But the battle continues to educate accountants, compliance officers, lawyers, as well as new regulators, oil executives, and indeed reporters, that you cannot impose a theoretical concept on the way that oil contracts are traded and reported – at least, not if you want oil to be competitively and sensibly priced.

Secondly, what is feasible today might not be feasible tomorrow. A price series that becomes a benchmark needs to be sustainable. A price series that emanates from a proprietary electronic platform and is based on the highest bid and the lowest offer for a standard contract is a valid way of assessing a market price. But what happens if there is no bid or offer? Constructing a price



series from reported prices based on transactions for a standard contract within a specified time frame is also a valid way of assessing price, but what happens if there are no transactions? Most people understand the concept of default procedures; but if these situations are not isolated events but regular occurrences, at what point does the methodology need to be officially changed or the benchmark abandoned in favour of another?

Thirdly, the price reporter's work is only feasible and sustainable if it occurs within a culturally acceptable environment. Gone are the days, at least in some parts of the world, when reporters were physically threatened, but legal threats are still common. Somewhat paradoxically, more regulation means fewer legal threats, but the overall environment of regulation leads companies to avoid actions which are perfectly legal (and indeed often encouraged by regulators) simply to avoid any possible litigation. So what is the point of accurately reporting the market's buy/sell range if corporate lawyers advise against using such a price series – not because it is illegal or inaccurate but because it costs time and effort to defend, possibly in a court of law, when an alternative exists using transacted prices that will not provoke such scrutiny or criticism, however unwarranted?

What has changed?

The cultural acceptability of certain trading activities has evolved as companies adapt to managing price risk. This is most clearly seen in the price relationship between the physical market and futures. A generation ago, companies were exposed to absolute price movements in a way that they are not today. The trading of oil quickly adapted to the well-understood concept that all oil pricing is based on differentials and that differentials are more important, from an oil company's

perspective, than absolute prices. If a crude is on sale for a price that is lower than the aggregate price of the products within the crude, then it will be bought. If not, it won't be. The absolute price doesn't matter. All markets revolve around price differentials based on location, timing, quality, and contract terms. This is such a fundamental characteristic of the oil industry that industry actors are bewildered when, as happens all the time, stakeholders in government, the law, and the general public don't understand it.

If it is the differential that is important, then absolute price risk management can be transferred to a standardized contract for future delivery in the expectation that extra liquidity will be provided to the market from financial firms offering price risk insurance (and possibly even some speculative activity). All trade then depends on a pricing point for a futures contract in which there is high liquidity and high transparency. The differentials against this pricing point, and the differentials against these differentials, become the means of pricing crude and products. A price reporter's role then changes from reporting the initial pricing point to reporting the differentials that can ultimately be used to derive the implied price of any crude or product. The relationship between reporting agency and futures exchange is not competitive but complementary, with physical prices reflecting differentials that ultimately lead to a futures contract, and reporting the price of derivative contracts that are then cleared on an exchange. This relationship reflects price risk management through the use of physical benchmarks and futures.

The importance of cultural acceptability cannot be overstated. A generation ago it was regarded as legally impossible to trade oil derivatives in the USA. This led to a series of forward physical markets, which, under a different

jurisdiction, were legal. But the USA changed the interpretation of what was and was not legal in respect of derivative trading, and this changed the cultural environment in the US oil market regarding acceptable price risk management vehicles. A generation ago, innovation and efficiency in oil pricing came out of Europe, and with it innovation and development in price reporting. That European advantage no longer exists.

The USA has become a more friendly regulatory environment than Europe. This is ironic, because the Enron scandal at the turn of the century led to a US regulator effectively proscribing certain methodological approaches to price identification. The result was a US gas and power market that was less efficient than the incipient European gas and power market, which was only starting to liberalize. The anxiety about (or antipathy towards) physical price benchmarks that came out of the Enron debacle resulted in a cry for more regulation and a preference for price identification based on deals, both of which allowed for easier prosecution of anyone deemed to have broken the law. When the financial collapse of 2008 occurred, these anxieties intensified and spread across the Atlantic, where they were stoked by oil companies that disapproved of certain new methodological approaches introduced by the leading European price reporting service, Platts. The result, a decade later, is that Europe has a less friendly regulatory regime than the USA. By friendly, I mean allowing feasible, sustainable price identification in a flexible and supportive cultural environment.

In practice this means that a generation ago, price reporters would speak to market contacts, rapidly cross-check information on the telephone, and be constantly informed of developing issues and possible reasons to adapt



methodologies to deal with changing circumstances. Now, some companies refuse to verbally communicate with reporting agencies, not because it is illegal but to avoid unjustified accusations or unjustified scrutiny by the authorities. Communication is becoming increasingly electronic and limited to transactions, or firm bids and offers, because such information has an electronic trail that is acceptable to regulatory oversight bodies. This type of information is important for price identification but is not necessarily the best information in a world that revolves around price differentials. Not all differentials are reflected in simultaneous trade, or indeed through trade at all. It is a myth that all differentials are perfectly reflected in transactions at 4.30 p.m. London time because there is simply not sufficient liquidity or market depth in seaborne markets at any one moment in time.

Regulation has now placed the focus in price reporting on process rather than accuracy. Regulators cannot assess the accuracy of a price assessment as they do not have any means of knowing what is an accurate price in a market where price differentials are in constant flux. All they can do is check whether the process of identifying those differentials has been accurately fulfilled and whether the input data could be challenged for accuracy in court. This brings the issue of input data back to transactions and firm bids and offers, and leads market participants to limit information flow to those elements. Yet the oil industry revolves around differentials, and transactions in seaborne markets are few, because of economies of scale, and do not all occur at the same time, no matter whether a price reporting agency creates an illusion of a so-called market-on-close.

Restricting market information to transactions and firm bids and offers

allows regulators to prosecute more easily and allows market participants to avoid unjustified and costly regulatory scrutiny, but at the expense of market efficiency. If differentials between crudes, and between time periods, and between locations or contract terms are now calculated on restricted information rather than assessed and interpreted in a dynamically changing environment, then they will not be as accurate. If that is the case, then the more data inputs the better, which means that the liquidity associated with the smaller-lot pipeline markets of the USA is better than the illiquid large-cargo-lot market of the North Sea. The USA then becomes a more friendly environment for benchmarks, and Europe again relinquishes its traditional advantage over the US market.

None of this, of course, would make any difference were it not for the development of shale oil in the USA. Shale oil has increased US production; the USA will soon be the world's leading crude oil producer again. Shale oil has created a surplus at the US Gulf Coast, and that surplus is cleared as many sellers and buyers balance their requirements. The volume of trade, in small lots because it is pipeline based, means that there are many transactions used to generate deal-based indices. This is to the pleasure of regulators and the comfort of the industry. But most importantly, it has changed the psychology of the US market. What is and is not culturally acceptable has changed. The restrictions imposed on US crude exports have been removed. Prices on the US Gulf Coast can, and do now, reflect the global supply/demand balance. As the physical infrastructure continues to be built to allow this market to work smoothly, the first point of physical price discovery is now in the US Gulf, from which North Sea Brent now takes its lead. Only a few years ago the opposite was the case.

What does this mean for the future of oil benchmarks?

The US role will continue to grow, and at an increasing rate. This can already be seen in the traded volumes of the CME Group crude oil contract. The USA will become the first point of price discovery, beginning with the crude futures contract and then, through differentials, on to the US Gulf Coast. This will be where the global supply and demand balance is reflected through price. And this price will command the confidence of authorities because it will be based on transactions which are generated through a market which is a pipeline market. It will be well reported, because reporting transactions will be culturally acceptable, because the regulatory environment will favour benchmarks based on transaction-based price series. Europe's leadership in oil market innovation will fade.

This will occur, not because the USA will have more accurate pricing or a better pricing methodology, but because the price reporters will have a methodological approach that is more feasible and sustainable within a more culturally acceptable environment and that will be conducive to industry confidence. The oil market and its reporting occur at the interface of physical possibility and human activity. Unlike a generation ago, it is the USA which now has a regional surplus of crude oil and a more favourable trading environment. And that will be reflected in the benchmarks and the pricing methodologies of the future.

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INTRODUCING EUROPEAN BENCHMARK REGULATION

Evelien Van Den Arend & Payal Lakhani

The European Union (EU) has a new regulatory regime for benchmark administration that establishes core principles for commodity benchmarks, including those that relate to energy. This regime builds on studies and recommendations by the International Organisation of Securities Commissions (IOSCO), which were broadly accepted by the price reporting community and by benchmark users.

This new EU regulatory regime marks the first time that commodity benchmarks have been subject to direct regulatory oversight. Participants in the commodity markets are still digesting the implications of this regulatory framework for their businesses, but it is already shaping the way that benchmarks are designed and maintained and the way that individual firms interact with the providers of benchmark services.

A brief history of benchmarks

Benchmarks have experienced some turbulent times over the past couple of decades. Perhaps the first major scandal was when the fall of Enron revealed that false price reporting in the gas markets had resulted in the distortion of prices between the retail and wholesale markets.

In part because of the Enron scandal and in part because of the greater professionalization of price reporting agencies (PRAs), since around 2000 the majority of PRAs have introduced significantly more rigour into the process of price reporting. This has resulted in more robust price assessments, which in turn are used as benchmarks in a variety of financial products.

The first international regulatory framework was introduced by IOSCO in 2013 with the publication of the Principles for Oil Price Reporting Agencies (also referred to as the IOSCO PRA Principles) and the Principles for Financial Benchmarks, which covered other benchmarks used in financial derivatives.

Around that time, the LIBOR (London Interbank Offered Rate) rate-setting scandal highlighted further lack of transparency in the creation of one of the world's most widely used financial benchmarks. The LIBOR scandal had a direct impact on consumers, particularly in the EU, and again undermined confidence in a key global benchmark. The UK, home to the LIBOR, reacted by creating a specific regulatory regime for the benchmark, which it also rolled out to seven additional specified benchmarks.

During that same period, the EU worked on its own regulatory framework for benchmarks, which was ultimately adopted in 2016. Regulation (EU) 2016/1011 of the European Parliament and the Council of 8 June 2016 dealt with indices used as benchmarks in financial instruments and financial contracts (the Benchmark Regulation).

Recital 1 of the new regulation summarized the EU's principal objectives:

The pricing of many financial instruments and financial contracts depends on the accuracy and integrity of benchmarks. Some serious cases of manipulation of interest rate benchmarks such as LIBOR and EURIBOR, as well as allegations that energy, oil and foreign exchange benchmarks have been manipulated, demonstrate that benchmarks can be subject to conflicts of

interest. The use of discretion, and weak governance regimes, increase the vulnerability of benchmarks to manipulation. Failures in, or doubts about, the accuracy and integrity of indices used as benchmarks can undermine market confidence, cause losses to consumers and investors and distort the real economy. It is therefore necessary to ensure the accuracy, robustness and integrity of benchmarks and of the benchmark determination process.

Making a benchmark robust

Benchmarks provide a reference point for a financial instrument and indicate how that instrument should be managed on an on-going basis from the perspectives of both risk and return. Benchmarks also allow investors to gauge the relative performance of their investment, and allow users to compare one product, service, or commodity with another or track its performance.

A benchmark was defined in article 3.1(3) of the Benchmark Regulation as

any index by reference to which the amount payable under a financial instrument or a financial contract, or the value of a financial instrument, is determined, or an index that is used to measure the performance of an investment fund with the purpose of tracking return of such index or of defining the asset allocation of a portfolio or of computing the performance of fees.

In turn, an index was defined in Article 3.1(1) as any figure:

- a) That is published or made available to the public;
- b) That is regularly determined:



- I. Entirely or partially by the application of a formula or any other method of calculation, or by an assessment; and
- II. On the basis of the value of one or more underlying assets or prices, including estimated prices, actual or estimated interest rates, quotes and committed quotes or other values or surveys.

The IOSCO Principles (particularly the principles for PRAs) referred to above set out a framework and recommended the following to index providers, aiming at improving the quality of the benchmark:

- Technology making it possible to track inputs and, more importantly, subsequent changes to them
- Internal policies dealing with conflicts of interest
- Compliance monitoring functions of the creation of any indices (including price assessments)
- Staff training on the framework and principles to be followed
- Transparency in relation to the employed methodology (including compliance statements and external audits)

The EU regulatory framework goes further. It establishes a range of benchmarks and classifies them based on the importance of the underlying notional value of the instruments that use them as a reference (critical, significant, and nonsignificant). It also distinguishes between different types of benchmark – regulated data, interest rate, and commodity – and applies a different degree and level of rules to each.

At a practical level, the EU regulatory

framework embeds the following core attributes that officials believe will generate more robust benchmarks.

- **Clarity and transparency:** The components of a benchmark should be clearly defined and representative of the underlying market. To further build confidence and market efficiency, a benchmark needs to be transparent and accessible. Trust in and understanding of any benchmark would benefit from a high degree of transparency in the process by which it is determined. Knowing how a benchmark is derived and what information it encapsulates would support a more sophisticated application of the benchmark in other markets. However, transparency needs to be carefully balanced against confidentiality, as the release of institution-specific information could lead to market manipulation.
- **Investability:** The benchmark should contain components that an investor can purchase in the market or easily replicate. It should be current and reliable.
- **Measurability:** The benchmark should be clearly specified prior to the start of the evaluation period and be calculable on a reasonably frequent basis.
- **Availability of historical data:** Historical data should be kept and made available with identities and/or weightings clearly defined.
- **Low turnover:** High turnover in the components of an index and constant change in its makeup can make it hard to put value on it.

- **Fair and robust methodology:** The benchmark should be constructed prior to the start of evaluation, using a transparent and consistent methodology, which is specified in advance. The mechanism used to compile and calculate it should be sound and be subject to regular internal scrutiny and controls to underpin its reliability. A benchmark should reflect the true value and risk of the activity whose price it determines. It should ideally be based on verifiable data and rooted in sufficiently liquid and frequently traded markets.
- **Published risk characteristics:** The benchmark provider should regularly publish detailed risk metrics and other information which is material to user's decisions when it comes to using a benchmark.
- **Good governance:** The benchmark provider should focus on designing and maintaining the benchmark in a way that ensures integrity and reliability; validating input data, monitoring conflicts of interest, and ensuring appropriate record keeping and audit trails; and maintaining practices that prevent abuse of the market. A benchmark must be trusted by market participants; this requires firm ground rules and governance structures that build trust and help avoid manipulation. The process of setting the benchmark needs to be governed by a clear and independent process that is free from conflicts of interest and limits its susceptibility to manipulation or price distortion.



- Formal oversight: Confidence in the benchmark may be further enhanced through formal regulation and oversight and an appropriate sanctions regime for improper conduct. This would improve the incentive system that underlies benchmarks, sharpen accountability, and as a result add rigour to the process of compiling benchmarks.

Conclusion

The primary driver of the European legislation was to deal with lingering suspicions that major benchmarks that affect ordinary European citizens, such as LIBOR, might be subject to undue influence by certain parties.

Commodity benchmarks were caught up in the general desire to regulate benchmarks that have dependent financial instruments rather than being the specific focus of the regulatory drive. Nonetheless, the legislation does capture the work of the energy PRAs, and it does impose additional burdensome requirements beyond those already envisaged by the recommendations previously issued by IOSCO. The requirement to register benchmarks with the authorities and the related cost could be a barrier to entry for smaller PRAs, while there are concerns that greater scrutiny of the benchmark production process may deter some energy firms from participating in price discovery, thereby reducing the flow of information to PRAs.

Despite some participants' reservations about the nature of the new regulations, there is no serious expectation of any reform of the rules in the immediate future. To date the energy markets are adapting relatively smoothly to the new requirements, and little obvious impact has been noted by the majority of

benchmark users, even if behind the scenes the regulations have required a change in approach by the producers of energy benchmarks.

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THE RESILIENCE OF THE BRENT BENCHMARK

Colin Bryce

The first cargo of the oil that came to be known as Brent Blend was exported from Sullom Voe, Scotland, aboard the Shell tanker *Donovania* at the end of November 1978. This wholly physical oil transaction predated the development of an over-the-counter paper market in Brent (15-Day Brent) and was transacted towards the end of a well-documented period of closed long-term contracts and lines of trade between producers and consumers with little need for intermediaries or price references other than official selling prices.

The late 1970s/early 1980s was a time of rapid market development, as the coincidence of the start up of North Sea production along with various geopolitical dramas led to the development of spot, shorter-term market-based contracts, price volatility, and the concept (then new) of hedging.

Techniques and venues developed quickly to mine the opportunity provided by the sudden transparency and opening up of markets. First to the new game was 15-Day Brent – the creation of Shell UK under Trading Manager Peter Lane – which put some standard terms around a paper market and provided for its liquidation into a physical cargo at expiry. It soon became clear that 15-Day Brent could be used by North Sea producers to optimize their tax contribution through an exercise known as spinning.

Liquidity begets liquidity, and it was not long before independent trading

houses, Japanese shosha, and most of the traditional industry-established trading desks began to play the markets. Some were amply rewarded; but the odds against betting the market without an edge left some holding big losses.

As liquidity developed, so did the desire for a higher level of sophistication and a more perfect hedge. Incumbents wanted to be able to hedge using an instrument benchmarking prices within their specific geography, as well as in the size they required.

The first mover to add some precision was the New York Mercantile Exchange with its West Texas Intermediate (WTI) contract. It addressed the issue of size of trade, in that small volumes could be transacted, against the 15-Day Brent requirement for trades to be in 500,000-barrel cargo sizes.

It was left to the over-the-counter market and particularly to 'Wall Street refiner' Morgan Stanley to create a 'partial Brent' market to satisfy the needs of geography and volume in Europe, attempts by the International Petroleum Exchange of London to set up a futures contract in Brent having failed.

The 'partials' market instantly appealed to a number of participants: ICI, Lasmco, Conoco, and Petronor (now part of Repsol) were some of the first to use the liquidity provided on call with a two-way quote, and many others followed.

So successful was this creation that the International Petroleum Exchange, now ICE (Intercontinental Exchange) Futures Europe, finally successfully listed an appropriate futures contract, which soon relegated the partials market to second fiddle.

For more than 35 years, 15-Day Brent (renamed and with somewhat reconstituted terms) has traded as an



over-the-counter instrument, convertible to a physical Dated Brent cargo, alongside a vibrant futures contract (enhanced in liquidity by the participation of financial market speculators and investors) and now hosted by ICE.

Despite the many changes in terms as it has evolved, over-the-counter Brent has demonstrated a remarkable resilience in the face of some serious challenges. The Dated Brent benchmark price, discovered daily by price-reporting agencies such as Platts and Argus, is thought to be the reference for more than 70 per cent of the world's crude oil production.

Brent has faced challenges since the beginning. As long ago as March 1987, the doyen of industry commentators, the late Jan Nasmyth, wrote in his eagerly awaited Weekly Petroleum Argus of the concerns over liquidity in the 15-Day Brent market. Today, over 30 years later, there are those who express similar concerns. There has been a history of challenges resulting from bad behaviour in the markets as well as from irresponsible and unauthorized trading resulting in the collapse of firms, with a consequent Carillion-like domino effect – as experienced by Gatoil, Transworld Oil, Klockner, Metalgesellschaft, and many more. The Brent complex and its participants have seen them all off in a practical example of the positive power of self-regulation.

Dated Brent has grown dramatically in stature over the last 35 years plus, as a relevant and transparent benchmark hosted by the industry and governed by a trustworthy legal system. Not a little help also came from the forceful creativity of the price assessor Platts and its key staff in cajoling the industry into on-going fine-tuning of the technicalities of the marker in order to maintain and extend its relevance. This has not, however, happened without a

legacy of complexity, so often the consequence of incremental tactical change.

The Dated Brent marker may now be at the threshold of a new challenge – one which may require a strategic rather than a tactical solution. The issue is whether there is sufficient underlying producing volume and consequent transactional evidence from the declining output from the Brent, Forties, Oseberg, Ekofisk, and Troll components of the assessment.

By the early 2020s, daily combined production may fall below the perceived critical threshold, needed to support the price assessment, of one cargo per day. The potentially straightforward tactical solution is to turn to the coming start-up of the Norwegian oil field, Johan Sverdrup (JS). Although publicly available assay detail on this grade is hard to come by, it would appear to be conventional wisdom that JS will be heavier and more sour than anything already in the assessment, with the possible exception of the Buzzard field component of Forties Blend.

However, the original Dated Brent, as a light sweet stream pricing as a benchmark for other light sweet oils, is long gone. This is due to the advent of heavier and more sulphurous elements in the basket, with the intrusion of quality and sulphur adjustment mechanisms and with the reach of the benchmark extending to the pricing of sour heavy grades of oil across the globe. Brent is arguably as much a brand these days as a specific type of oil.

Notwithstanding such developments, the precedent is only partially appropriate, as the Dated Brent delivery mechanism has yet to deliver a crude of the quality of JS. However, in a world where refining equipment is becoming increasingly complex and the global crude oil quality median outside

of the USA is becoming heavier and more sour, this is not an insurmountable challenge.

The key players in this next evolution are expected to be Platts as the assessor, Shell UK as the guardian of the SUKO 90 terms (which govern the paper-to-physical conversion), ICE as the futures listing venue, and Statoil as the dominant producer of JS (along with the other unitized field owners).

While it seems necessary to seek a quality adjustment solution to encompass JS in the assessment of the benchmark to retain its efficacy, it may not be sufficient in the long term, as production volumes from this field are estimated to be only at a level that will replace and not extend underlying Dated Brent complex production beyond the medium term.

There is also production risk. If JS performance is similar to that of the Heather field, which never reached more than a small percentage of predicted levels, then Dated Brent will be looking for a Plan B.

Plan B currently involves one or both of two major strategies. The first is to consider bringing Urals crude (well regarded by European refiners) into the assessment. Aside from the obvious geopolitical complexity, there are questions of changing quality of Urals in the future as more Russian crude is directed east. There are also issues associated with the lack of transparent FOB trades in Urals despite the large underlying production and other concerns about the ability or propensity of stakeholders to exercise market power.

The second strategy, also fraught with challenges, involves a change in the benchmark from an FOB (free on board) to a CIF (cost, insurance, and freight) assessment. Netting back freight to arrive at a reliable, observable 'clean' price creates a further layer of



complexity. This is the reason the most established and widely traded benchmarks have arisen at production locations or as FOB contracts, rather than at consuming locations. Furthermore, significant deliverability issues surround the idiosyncratic approach to ship vetting and vessel acceptability of incumbents likely to receive deliveries.

However, Platts have been quoting a CIF price for some time now, and there is some interest in exploring this route in some quarters in the industry.

Most participants, whether traders, oil companies, funds, or other entities, would prefer the key stakeholders to sort all this out and keep the show on the road with the minimum of fuss. ‘Just do it,’ as the slogan goes, is the order of the day. As International Organization of Securities Commissions (IOSCO) benchmark regulation takes effect, how these key market leaders address questions of benchmark stress will assume a critical importance.

What is clear to intelligent commentators and participants in the crude oil markets is that each competitive benchmark (such as Brent and WTI) benefits from the existence of the others, such that liquidity is bolstered by regional arbitrage and speculation across geographical differentials.

All the current leading benchmarks in crude oil have flaws: WTI is landlocked, Brent suffers from lessening production, regional antipathy hinders Oman/Dubai, and WTI Gulf Coast has logistical/quality standardization issues. Indeed, while some have asserted that ‘Brent is Dated,’ it be also be asked: Exactly what is WTI?

So who will initiate the necessary conversations to determine the future of the Brent brand? As in the past, this calls for the leaders in the Brent milieu

to strategize together to choose the solution most suitable for all stakeholders. Platts, ICE (assisted by Energex Partners as interlocutor), and Shell, at the least, are in conversation and will be guided by the need for transparency, simplicity, legality, timeliness, and the effective continuation of the storied concept that is Dated Brent.

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THERE CAN(NOT) BE ONLY ONE

Liz Bossley

Oil traders attending the February 2018 International Petroleum Week would be forgiven for concluding that there is a fight to the death going on between the Intercontinental Exchange (ICE) and Platts on one side and Argus and the CME Group (CME) on the other for supremacy over oil price benchmarks. The ICE/Platts coincidence of interest is characterized as supporting King Brent, specifically Platts Dated Brent, and Argus/CME are portrayed as flying the Young Pretender’s flag of West Texas Intermediate (WTI) at Houston, specifically the Magellan East Houston quotation published by Argus.

But nothing could be further from the truth. This is not Highlander, and there can be – in fact, it is essential to the health of the market that there is – more than one key price reference point, or benchmark, to which traders can refer when pricing their contracts.

What is a benchmark?

The majority of contracts for physical oil around the world include a formula that determines the ultimate invoice price of the cargo. The counterparties to the deal do not agree on a fixed and flat price of, say, \$65.37 per barrel at the time the deal is struck. The price clause often requires the counterparties to calculate the price in accordance with a formula. The formula usually includes

as the main variable a benchmark price – say, Brent, as published by Argus or Platts or as traded on CME or ICE – on three to five specific days in the future, usually around or after the loading date of the oil. The loading date is usually determined by the tanker’s bill of lading.

Hence, one of the key prerequisites of a benchmark grade of oil is the existence of a market in that grade expressed as a fixed and flat number, \$X per barrel, not by reference to a formula. Otherwise the price equation could never be solved. The most active crude oil benchmarks are those where there is liquid trading in a fixed and flat price, that is, a forward or futures contract or some type of swap. In the case of Brent, the fixed and flat contracts are the 30 day Brent-Forties-Oseberg-Ekofisk- Troll (BFOET) deliverable contract and the Brent futures contracts; in the case of Dubai, there is a swap market and the Dubai Mercantile Exchange/Oman futures contract into which Dubai can be delivered. In the case of WTI, there is the futures contract deliverable at Cushing, Oklahoma. Fixed and flat numbers from these sources are plugged into price formulae in physical contracts to establish the invoice price.

The price formula will typically also specify a differential to account for any differences between the quality, quantity, and delivery date of the benchmark and those of the grade of oil being traded. This differential formula may be a pre-agreed fixed and flat number or, if the grade in question is widely traded and assessed by the price reporting agencies (PRAs), the differential may itself be a formula solved by reference to a PRA differential assessment, typically on the same three to five days used to determine the benchmark element of the price formula.



Other price reference points

The PRAs derive the price of grades that are not benchmarks, such as Bonny Light in Nigeria, Urals in the Mediterranean, or ESPO (East Siberia–Pacific Ocean) at Kozmino as a differential versus a bona fide benchmark. Although such key reference points are essential to the market, they cannot be considered true benchmarks because they do not trade at a fixed and flat price.

Anyone looking to buy a cargo of a new grade of oil that is not assessed by the PRAs in, say, West Africa, would most likely compare the gross product worth (GPW) of the new grade with the GPW of Bonny Light, which is freely traded and assessed by PRAs as a price differential to Dated Brent. The starting point for price negotiations would not be the GPW differential between the new grade and Brent, because Brent is no longer a single grade of oil: it is a basket of Brent, Forties, Oseberg, Ekofisk, and Troll, with the lowest price in the basket determining the price of Dated Brent on any given day. Hence traders would be hard pushed to know the assay of which Brent basket grade to use if they were trying to establish the GPW of the new grade versus Brent. It is much easier to establish the price of a new grade versus a grade that already has an established market price differential to Brent and work out the GPW differential to Brent as a compound differential to the established reference grade, such as Bonny Light.

Other grades of oils, such as Urals and ESPO and some Middle East grades, are similarly pivotal differential referencing points and are derived from their traded market price differential to one of the main benchmarks. Several could easily become benchmarks over time if the traders made sufficient deals at fixed and flat prices. This is not an outcome that can be engineered easily

by regulators or other authorities, although the Chinese yuan-based futures contract may be the exception that proves that rule.

At the moment the price of WTI at Houston is a price referencing point rather than a benchmark because it trades at a differential to WTI at Cushing, not at a fixed and flat price. It is fashionable to predict that this will change over time because of burgeoning exports through the US Gulf Coast. But this is not a foregone conclusion. WTI at Houston has a few more hurdles to jump before it takes its place in the pecking order of international crude oil price benchmarks.

WTI at Houston as a benchmark

Other important characteristics that a benchmark would have in an ideal world are:

- a large volume of production in diverse hands to prevent one company controlling supply,
- a large number of refiners/blenders able to accommodate the grade in question so that the price is not vulnerable to refinery turnarounds or other shifts in demand,
- stable quality that does not have any particularly difficult quality attributes,
- good loading terminal logistics with enough storage to accommodate a number of days of production with sufficient flexibility to handle operational changes and shipping delays,
- sufficient jetties with capacity to load a range of tankers to optimize freight and promote inter-regional arbitrage,
- a transparent lifting schedule,

- standardized, transparent general terms and conditions of trade, and
- a benign host government that does not intervene in either price or supply.

WTI in the Houston area appears to tick many of these boxes. There are certainly a large number of producers, although export power is not in the hands of a myriad of small producing companies. Instead it is in the hands of aggregators, many of whom are themselves large oil producers and/or traders and/or refiners who perform the role of gathering the crude into pipelines for delivery to the US Gulf Coast and export from Houston, Corpus Christi, and Beaumont/Port Arthur in descending order of current throughput. Apart from the Gulf Coast refineries themselves, WTI ex-Houston has already been exported to at least 12 other countries, not least of which is China. So there appears to be no harmful concentration of buying power in too few hands.

This diversity of buyers is aided by, so far, the known and stable quality of light, sweet oil: WTI at Houston is reported by Argus to be 44°API and 0.45 per cent sulphur, compared with 40°API and 0.37 per cent sulphur at Cushing. Barrels at Beaumont/Port Arthur are widely recognized to be inferior and of a more variable quality than those at Houston or Corpus Christi. This is because Beaumont/Port Arthur barrels can be delivered via Cushing (with the risk of blending), whereas Houston and Corpus Christi barrels have direct pipelines from the Midland, Texas, area.

Logistics are a significant challenge to WTI at Houston's bid to be a benchmark. There is plenty of storage and import capacity in the US Gulf Coast; the export capacity is unclear but is known to be growing. A potential buyer of WTI at Houston has to shop



around to find out exactly where and when cargoes can be made available and in whose hands the oil currently resides. This compares unfavourably with the Brent basket, the availability of cargoes of which is published widely by terminal operators each month.

As yet, there are no standardized WTI cargo sizes, with some cargoes going to northwest Europe on Aframaxes and others going to China and other Asian countries in very large crude carriers (VLCCs) that have been gathered offshore by trans-shipments. The three export ports of Houston, Corpus Christi, and Beaumont/Port Arthur cannot load VLCCs directly. In time we may see VLCCs of sweet crude loaded through the Louisiana Offshore Oil Port, but the cost of getting the crude from St James to this port is currently about \$2 per barrel, making this export route uneconomic.

In time, flexibility in parcel sizes will be seen as a virtue, boosting the relative price of WTI at Houston; but in the short term, the lack of clarity is detrimental to the emergence of the sort of physically deliverable forward contract at a fixed and flat price that was the precursor to the emergence of the Brent benchmark – that is, the 30 day BFOET market in 1981 and the Brent futures market seven years later. VLCCs are too large to lend themselves easily to an active forward contract, excluding all but the largest oil companies and traders. Even at 600,000 barrels the BFOET contract is not easily digestible for many players, who choose instead to use swaps in 50,000 barrels Brent partials or futures contracts of 1,000 barrels per lot.

Buyers of WTI at Houston must negotiate a contract with sellers; there are, as yet, no standard general terms and conditions of trade like the SUKO 1990 terms that govern Brent forward trades. So a buyer at Houston who wants to trade a cargo on to a third

party runs the risk of not being back-to-back on its purchase and sales terms.

The barriers to WTI at Houston's development as a benchmark price are easily fixable, and the race is on to be the company that controls the storage, lifting schedule, and general terms and conditions.

Whether the US government can be currently described as a benign host government is a matter of opinion. Supporters of the WTI at Houston market as a benchmark would be well advised to consider whether a president who would like to build a physical wall against the country's neighbours and says that 'trade wars are good, and easy to win' can be considered benign.

Meanwhile, back in the North Sea

Brent is still limping along with poor liquidity as production of the BFOET basket continues its downward trajectory. A complete force majeure on the largest component of the basket, Forties, for more than 20 days in December 2017 had remarkably little impact on its relative price, indicating that the issue described in the OIES paper Oil Benchmarks: What Next? of March 2017 still prevails. The issue is that when the supply of Forties dries up, the price of Forties does not rise, as economic theory would suggest, making it necessary for sellers to be paid a quality premium to encourage them to supply the apparently higher-priced Oseberg or Ekofisk into sales contracts for 30-day BFOET. There is no quality premium for sellers who supply Brent or Troll instead of Forties into a forward contract.

It is increasingly recognized that the somewhat arbitrary price premiums, based on a proportion of historic price differentials, that are applied to Oseberg and Ekofisk cargoes supplied into 30-Day BFOET contracts are inadequate to the needs of a healthy,

liquid market. It is accepted that some form of prospective quality adjustment will be needed before Troll ever contributes to the physical supply. If the heavier, higher-sulphur, higher-acid Johann Sverdrup volume is to be added when it comes online at the end of 2019, a more comprehensive value adjustment mechanism will be needed. Recognition of this need is growing but is not universal.

Spreads are part of the market

Clearly there is much work to be done to repair Brent and to facilitate the progress of WTI at Houston towards benchmark status. In carrying out this work, it should be borne in mind that a huge proportion of liquidity in the market is attributable to spread trades amongst benchmarks and between benchmarks and other price reference points. It is unhelpful to behave as if WTI at Houston can only succeed at the expense of Brent. The market needs more working benchmarks, and that presupposes that all interested parties are working towards the ultimate solution of a range of efficient benchmarks promoting inter-regional arbitrage.

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STRESS TESTING THE WEST TEXAS INTERMEDIATE (WTI) BENCHMARK

Dan Brusstar

Several key characteristics determine the adoption of a benchmark and its ultimate success as a price-setter in the oil marketplace. Of these, nothing is more important than the ability to withstand the test of time and adapt to the needs of the marketplace. The oil markets are highly dynamic and continually evolving, and it is critical that a benchmark be responsive to the changing marketplace. The West Texas Intermediate (WTI) futures benchmark has endured and thrived over the years



due to its ability to change in times of stress and to remake itself to meet the needs of the market.

In his book *Anti-fragile: Things That Gain from Disorder*, Nassim Nicholas Taleb presented the theory that things gain strength if they respond positively to shocks and stress testing, and that applying stress and pressure are necessary as a catalyst in the process of remaking and improving something. The process of stress testing and breaking something forces a reworking that can lead to a better, more robust end product. Indeed, looking back historically, the WTI benchmark has endured shocks and was considered 'broken' on two separate occasions, and each time it was forced to change. Ultimately, it emerged after each stress test to be a better and more reliable price indicator.

This article discusses some of the factors that contribute to the success of a futures benchmark, and then examines two occasions in which the WTI benchmark was pushed to the breaking point and was remade into a leading global benchmark.

In the competitive marketplace, a successful futures benchmark should be structured to meet the needs of the oil industry as it strives to accurately price and hedge commercial transactions. There are key characteristics that a futures benchmark must satisfy:

1. Liquidity and robustness in the underlying cash market

A price benchmark is useful only if it is based on activity in an existing physical cash market that is robust with diverse commercial participation. Over time, the oil industry has developed key pricing hubs where commercial transactions are executed in a competitive

marketplace, where a reliable price can be established and verified. The WTI futures contract was launched in March 1983 based on physical delivery of light sweet WTI-type crude oil at an existing hub in Cushing, Oklahoma, where a robust and flourishing cash market provided a solid foundation for a benchmark. It is important that a benchmark is tied to a robust underlying cash market so that the price reference is meaningful and verifiable.

2. Transparency and reliable information on market fundamentals

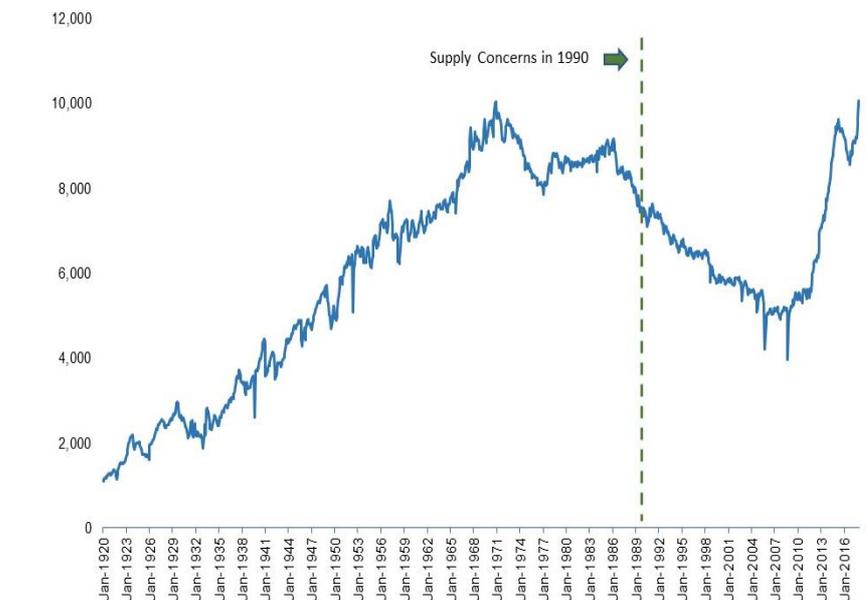
Another critical success factor for a benchmark is transparency and information on a real-time basis to ensure that the price indicator is market-responsive and reliable. The WTI futures benchmark provides a transparent price reference that is available 24 hours a

day and is a reliable signal of demand and supply fundamentals in the marketplace. Further, the US Energy Information Administration (EIA) publishes relevant demand and supply data on a weekly basis that is critical to the WTI price-setting mechanism. The market relies on data to ensure that the price formation process accurately and immediately reflects market fundamentals.

3. Straightforward and direct convergence with the physical oil market

A critical factor that makes the WTI futures contract unsurpassed is the direct physical link to the underlying cash market in Cushing. The true test of a futures benchmark comes at expiry when the pricing of the futures contract converges with the physical market price, so that the settlement price is based

US crude oil production (1920-2018) thousand barrels per day





on real transactions that accurately reflect the underlying market. The WTI futures contract has become the industry standard for reliability in establishing a price signal that is tied directly to physical delivery of oil.

4. Adequate production in the underlying cash market

The demand and supply dynamics that underpin a market have a strong impact on the long-term viability of a futures benchmark. The increasing US oil production is clearly supportive of the WTI benchmark, but there was a time in the 1990s when declining US production was a serious threat to it. Similarly, declining oil production in the North Sea is putting pressure on the Brent benchmark, and additional supply sources will be critical to its continued viability. In the end, it is vital that a benchmark is supported by adequate production in its underlying market to ensure a stable supply base.

5. Relevant price reference in commercial contracts

Another key characteristic of a successful futures benchmark is its adoption as a price reference in commercial contracts used in the oil industry. Over time, the industry will imbed the price in its long-term contracts, which then solidifies the importance of the benchmark. The WTI futures settlement price is used widely in the marketplace, not only to price WTI-type crude oil but

also as the price anchor for all US sweet and sour crude oil grades.

Ultimately, the most important feature of a benchmark is its ability to endure the test of time. The WTI benchmark has endured shocks and stress over the years, and was considered a broken benchmark; but each time this happened, it was remade, and it has emerged as a superior price mechanism.

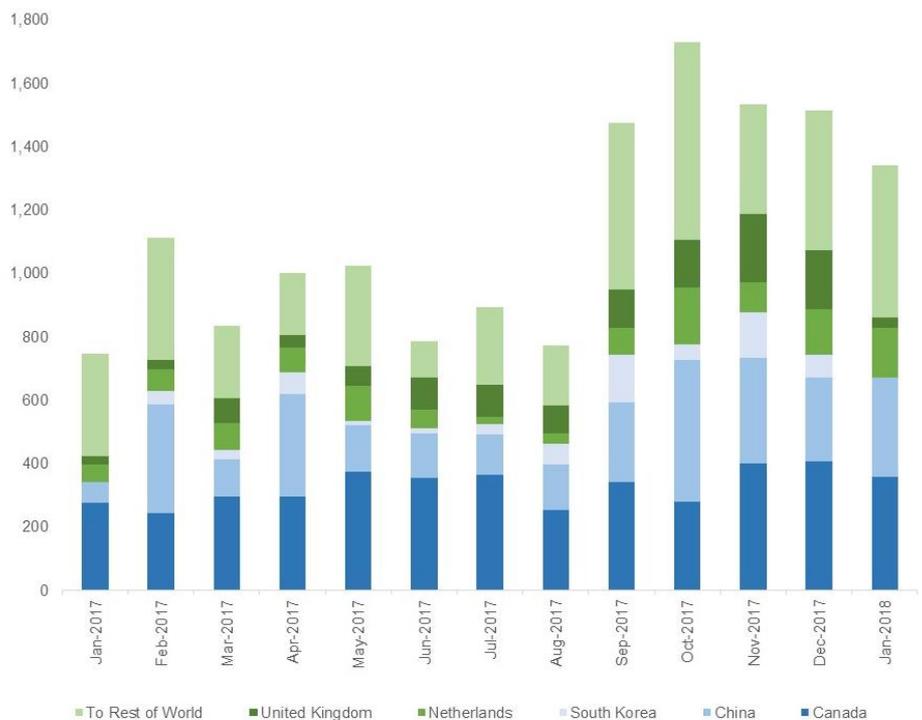
Surviving stress, emerging stronger

On two occasions, in 1990 and 2007, the WTI futures benchmark was subjected to shocks that threatened its viability. In 1990, when US crude oil production was declining rapidly, the WTI futures benchmark was threatened with a shortage of deliverable supply, and many industry participants began

to question its validity. It was feared that the WTI would become a regional price marker that reflected a diminishing underlying market. Indeed, US oil production had peaked in 1970 at 10 million barrels per day (mb/d), and by 1990 had slipped to 7 mb/d. At the time, analysts were forecasting further declines, and US oil production ultimately fell below 5 mb/d.

In response to the supply crisis in 1990, the New York Mercantile Exchange (now a subsidiary of CME Group) worked in consultation with oil industry participants to seek additional supply sources to underpin the physically delivered WTI futures contract. Only one pipeline, Seaway, provided a direct inbound connection to crude oil supplies from the US Gulf Coast, where foreign crude oil grades could be sourced. Consequently, the Exchange

US oil exports by country of destination (thousand barrels per day)



Source: US Energy Information Administration



and the oil industry agreed to allow physical delivery of several foreign crude oil grades, including Brent and Bonny Light, against the WTI futures contract to provide a backstop in the face of declining US oil supplies. This solution fix was critical, because it provided a direct physical link between WTI futures and Brent-related grades, and assured the viability of the WTI–Brent arbitrage.

Again in 2007, the WTI futures benchmark was shocked by the explosion and shutdown of Valero’s McKee refinery, which is supplied directly by Cushing via a pipeline. The explosion knocked out the refinery for almost two years and cut crude demand in Cushing by over 150,000 b/d. This shock caused crude supplies in Cushing to swell, and there was limited outbound pipeline capacity to relieve the storage glut. The inbound flows of foreign crude oil on the Seaway Pipeline declined in response, and consequently, the WTI benchmark became disconnected from the US Gulf Coast market. At the time, the Seaway Pipeline was unidirectional and was unable to take away burgeoning crude supplies from Cushing. As Seaway Pipeline flows dwindled to a trickle, the oil industry and the Exchange supported a reversal of the pipeline to allow crude oil to flow outbound from Cushing to the US Gulf Coast. In November 2011, Seaway announced it would reverse the pipeline, and in May 2012, the reversal was completed by its joint owners, Enterprise Products Partners LP and Enbridge Pipeline. This pipeline reversal established a direct southbound link between WTI in Cushing and the US Gulf Coast market. The 2007 refinery explosion, and the resulting reduction in southbound flow capacity from Cushing, immediately impacted the WTI–Brent price spread, which bulged to a record \$25 in 2013 in the aftermath of the 2007 shock – a

good reflection of the extreme stress that the WTI futures benchmark endured. As Nassim Nicholas Taleb’s theory predicted, the severe shocks to the WTI futures benchmark led to its breaking down and remaking, which ultimately made it better. The WTI benchmark emerged after each shock event as a transformed price indicator that has endured the test of time.

A look ahead

Today, the tested and reworked WTI benchmark is enjoying a renaissance in the global marketplace, as the US ramps up oil production and becomes a major oil exporter. The oil industry has responded to the 2012 Seaway Pipeline reversal with significant new pipeline infrastructure that connects Cushing directly to the export hub in Houston on the US Gulf Coast. As a result, the outbound pipeline capacity linking Cushing to the coast is currently 1.5 mb/d, making Cushing a key supply source for the vibrant export market.

US crude oil production has nearly doubled, from 5.1 mb/d in January 2009 to 9.96 mb/d in January 2018. In its latest estimate, the EIA predicts oil production will hit a new record high in 2018 of 10.3 mb/d and then rise to 10.9 mb/d in 2019. According to the EIA, most of the growth in US crude oil production is WTI-type crude oil with API gravity between 40 and 45 degrees. This is significant for the WTI benchmark, as it underscores the similarity in quality between the new oil production and the WTI pricing reference.

US crude oil exports nearly doubled in 2017 to average over 1 mb/d, up from 600,000 b/d in 2016, which was the first year that US exports were allowed. The growth in exports has transformed the US crude oil market. Houston has become a major export hub, and new infrastructure has been constructed to process the growing export volumes.

These infrastructure changes have transformed the US into the marginal supplier of oil to the world.

Currently, oil market participants are pricing US oil exports based primarily on the assessment of WTI at Houston, which is quoted as a differential to the WTI benchmark price at Cushing. This differential is highly liquid and reflects the location basis between Cushing and Houston. The WTI benchmark at Cushing provides a reliable anchor as the flat price reference for the WTI priced at Houston. In addition, the liquidity of the WTI benchmark at Cushing helps to ensure the accuracy and reliability of the basis differential for WTI at Houston, where exports are priced.

The growth in US crude oil exports has been balanced and diverse, with strong participation from Asian countries. The broad participation indicates a well-developed export market that spans both Europe and Asia. As US oil exports gain deeper penetration in the global oil markets, the WTI benchmark will continue to expand its reach as the key price reference in the international marketplace.

With the remarkable growth in US exports, the WTI futures benchmark has become the key pricing and hedging tool for the global marketplace. It has withstood stress and shocks over the years, and today it is well-connected and battle-hardened as the price discovery leader in the world oil market.

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THE EMERGENCE OF ARGUS US CRUDE GRADES AS GLOBAL BENCHMARKS

James Gooder

In mid-December 2015, US lawmakers, desperate to avoid a looming government shutdown and impatient to start their Christmas holidays, voted a contentious spending bill through Congress. With a reluctant stroke of his pen, President Barack Obama passed the bill into law.

“I’m not wild about everything in it,” he said.

One of the things he was not wild about was the lifting of a virtually total ban on US crude exports, implemented in 1975 to protect US refiners and consumers from price spikes in the wake of the Arab oil embargo. Many Republicans and oil companies had been campaigning for years for the restrictions to be lifted, particularly following the US shale boom. In return, environmentally minded Democrats managed to negotiate extended tax credits for wind and solar energy. But for global crude markets, the cork was out of the bottle.

Relatively unrestricted exports of US refined products had been flowing into the market for years, but now, for the first time in the memory of anyone under 60, US crude producers were also competing in a global market. The nexus of this competition today is the US Gulf Coast.

The glut moves south, and clears

The US midcontinent had been dealing with an oil supply glut since early 2009, when weakening demand led to a stock build that began to overwhelm storage capacity at the Cushing market hub in Oklahoma, home to the CME’s benchmark light sweet crude futures contract, or WTI (West Texas Intermediate) futures. The start-up of

the Keystone pipeline in 2011 exacerbated the overhang by opening the way for more crude to move from western Canada to Cushing. The surplus dragged WTI crude futures down to a discount of more than \$20 per barrel to ICE (Intercontinental Exchange) Brent futures, and the following year’s reversal of the Seaway pipeline, originally built to bring foreign crude to midcontinent refineries, served only to move the glut south to the US Gulf Coast.

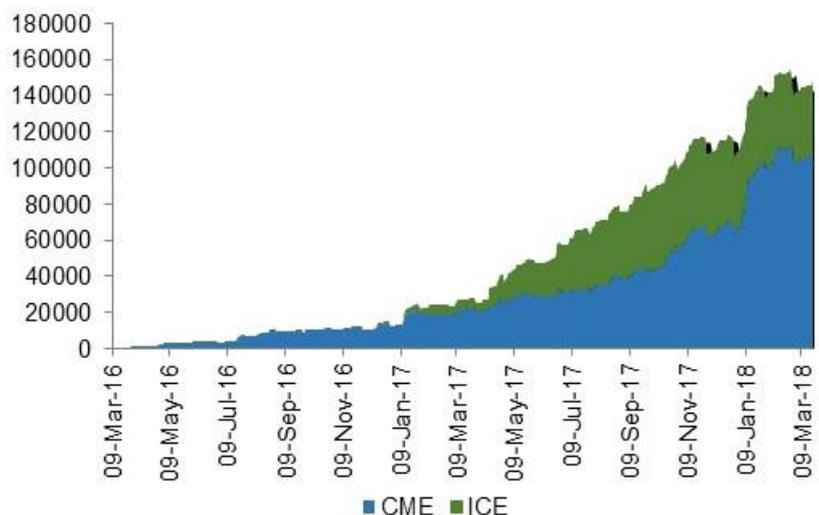
These new pipeline connections coincided with the historically unprecedented boom in US hydrocarbons production occasioned by the widespread take-up of advanced hydraulic fracturing and horizontal drilling techniques, which unlocked oil and gas in shale formations across the country. US crude production was a little under 5.5 million barrel per day (mb/d) in 2010, when the shale boom began to accelerate rapidly. That figure is projected by the US Energy Information Administration to exceed 11 mb/d in the fourth quarter this year and continue to grow to a plateau of about 12 mb/d in 2030. US tight oil output is poised to grow for the next two decades and to exceed 8 mb/d by the mid-2030s, when it will make up close to 70 per cent of total US crude

production, compared with 54 per cent in 2017.

By the time the brimming surplus of US crude had moved from the midcontinent to the Gulf Coast, assessments of the price of crude in the region by the independent price reporting agency Argus were already well established. US crude market participants were familiar with the agency’s method of compiling all-day volume-weighted averages of trade. This method is designed to create price indexes that are reflective of the whole market and encourage maximum liquidity and transparency, as every trade counts. It is most successful in markets with high iterations of daily trade, such as US pipeline crude markets and European gasoline barge markets, and is not practical in markets with far fewer trades of much higher volume each, such as the North Sea crude cargo market.

US Louisiana Light Sweet (LLS) crude, a blend of imported and domestic grades, was widely regarded as a measure of the value of light sweet crude at the US Gulf Coast. And reported trades of offshore medium sour grades Mars, Poseidon, and Southern Green Canyon fed into the Argus Sour Crude Index™, which

WTI Houston Open Interest (1000 barrel lots)





Saudi Arabia, Kuwait, and Iraq had adopted as a benchmark for their crude exports to the USA as early as 2009.

The benchmarks Argus LLS and Argus Mars were not designed to replace the outright price signal generated by trade in WTI futures. The grades at the US Gulf Coast trade at premiums or discounts to WTI futures, making the final physical prices a robust combination. This means that Argus's US Gulf Coast prices incorporate both the high volume of trade in CME Group (CME) futures delivered at Cushing – the world's most actively traded oil contract – and trade in the physical differentials adjusted for the different market conditions at the Gulf Coast. Given the high levels of usage of these prices in physical indexation, active derivative markets arose around the Argus differential prices to allow market participants to hedge their exposure to them.

WTI moves to Houston

WTI crude is gathered in west Texas, where it trades in a spot market in the inland town of Midland. But with the growth in infrastructure and the convergence of several streams of crude on the coast, primarily in the Houston area, a market emerged in 2015 at the latter locations.

The emergence of a spot market in Houston for WTI was initially facilitated by Magellan Midstream, which put in place an in-tank transfer system at its Magellan East Houston terminal that allowed for the open trading of crude. Since the launch of the Argus WTI Houston assessment in February 2015, spot market volumes have increased sharply. Participation has expanded to include majors, refiners, producers, and trading houses.

The liquidity of the WTI spot market at Midland, which had been so high in recent years, has now begun to transfer down to Houston. All of this trade

supports the Argus WTI Houston price assessment and makes the accompanying financial markets more useful as a hedge. As a result of the growth in the physical market, CME and ICE now list several futures contracts for WTI Houston, all of which are settled against the Argus price assessments for the grade. (The growth in open interest on these contracts is summarized in the figure below.)

Argus WTI Houston is supported by clear quality specifications. The WTI Houston market consists of Permian WTI crude shipped to the Magellan East Houston terminal through the 275,000 b/d Longhorn and 400,000 b/d BridgeTex pipelines, both of which set specification requirements for crude moving through their lines. Once at the terminal, WTI is stored in segregated tanks. This makes WTI Houston distinct from Domestic Sweet Blend (DSW) crude at Cushing or Houston. Blended DSW can vary significantly in quality and value.

The CME will allow for a broader range of tests as of 2019 to ensure that DSW delivered into its WTI futures contract meets a tighter specification than was previously the case. But many refiners prefer to do their own blending, so they opt for field-grade WTI.

Argus WTI Houston provides a stable quality against which more variable qualities can be traded. The WTI Houston market is backed by production in the Permian basin, which has remained resilient despite extended periods of relatively low crude prices. A particularly severe test was the landfall of Hurricane Harvey in late August 2017, which in addition to causing loss of life and extensive damage to private property, flooded several coastal refineries and disrupted some crude output. Argus continued to publish assessments and market coverage throughout, despite a flooded

Houston office, with staff working from remote locations.

The WTI Houston market continued to trade at stable levels relative to Brent and Dubai, even while WTI at Midland and CME's WTI futures saw prices plummet as a result of production shut-ins and a drop in demand.

Since the USA lifted its crude export ban, refiners in many parts of the world have been keen to see how the new US supply can fit into their accustomed feedstock diet. Buyers in northwest Europe, the Mediterranean region, East Asia, and India have become regular buyers of US crude. Asia-Pacific buyers tend to favour Permian quality WTI, trade in which underpins the Argus WTI Houston assessment, as its quality is predictable and stable.

An island no longer

Argus WTI Houston is the best indicator of price at the US Gulf Coast, which has become the balancing point of world crude markets, where the marginal barrel from Midland meets imported crude from other parts of the world, and increasingly, surpluses can be efficiently exported to meet demand elsewhere. The USA remains a large importer of crude, despite its rapidly acquired production riches, and this dynamic has placed it at the centre of global oil trade, rather than as an island apart.

To help facilitate trans-Pacific trade of US crude, Argus began in mid-2017 to publish prices of WTI Houston and Mars at the close of the trading day in Singapore. This allows Asia-Pacific buyers, accustomed to benchmarking their supplies of Mideast Gulf or Russian crude against the price of Dubai crude, to compare the value of US imports at the same timestamp.

The opportunity to ship US crude to the Asia-Pacific region has become a key determinant of crude prices in the growth markets of China, India, and



Southeast Asia. In November 2016, the OPEC group of producing countries and its non-OPEC partners, including Russia, agreed to curb output to clear a global surplus of crude and support prices. While this effort has not exactly backfired – WTI crude recovered from around \$45 per barrel at that point to nearly \$65 per barrel at the end of February 2018 – it has opened the way for US crude to find a foothold in OPEC’S core markets.

Tripolar disorder

The world of physical crude benchmarking remains tripolar. Dated Brent prices are dominant in the Atlantic basin, Dubai-Oman is used for Mideast Gulf exports, and CME WTI futures, adjusted by Argus’s US Gulf Coast differentials, provide the benchmark for the Americas. But East Asia lacks its own benchmark.

Regional crude price benchmarks Malaysian Tapis and Indonesian Minas were abandoned a decade ago because of low trade liquidity and perceptions that they did not fully reflect market fundamentals. At that point, Dated Brent was adopted in much of East Asia for the pricing of light sweet crude, despite being reflective of trade in the North Sea, half a world away. But many of the criticisms directed at Tapis and Minas are now being levelled at Dated Brent, which is suffering from low trade liquidity, a small pool of participants, and risk of disruption to ageing infrastructure, such as the rupture on the Forties pipeline in December 2017.

East Asia needs a representative benchmark for light sweet crude imports, and WTI Houston fits the bill. It enjoys the benefits of Brent, such as liquid derivatives markets and a stable legal and fiscal regime, as well as several improvements, including a wide spread of participants, high iterations of daily trade, near total market transparency, and flexible

infrastructure with several routes to market.

The next step in the evolution of the WTI Houston benchmark is to incorporate it into existing pricing relationships. We have already seen how the spread to Dubai is becoming a key determinant of crude prices in the Asia-Pacific region. On the other side of the world, traders have looked at the WTI Cushing-Brent futures spread for years as a measure of transatlantic arbitrage. But that spread was viewed through the prism of an understanding that crude could only flow one way — westward from the Atlantic basin to the USA. Now that crude can go in the other direction, and WTI Houston has proved to be the best measure of value of that crude at the coast from which it is exported, a WTI Houston-Brent spread is a more appropriate gauge of the arbitrage opportunity. Exporters to the USA are competing with WTI at Houston, not at Cushing or Midland.

The US shale boom and the lifting of the crude export ban have revolutionized the global crude market. And for those looking to understand how the new trading patterns operate, all pipelines lead to Houston’s market, its export terminals, and the world’s shipping lanes.

THE CHANGING NATURE OF THE DUBAI BENCHMARK

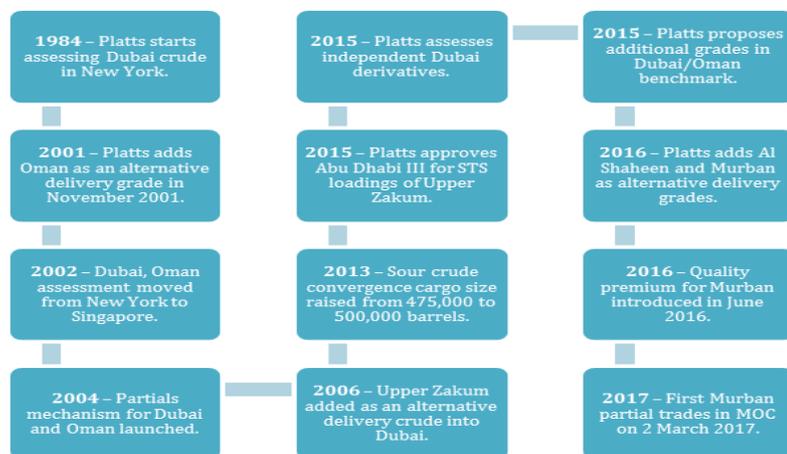
Dave Ernsberger

The Dubai benchmark has been at the forefront of innovation in crude oil benchmarks throughout the first decades of this century, ensuring it is well positioned to continue serving as the pricing basis for crude oil term supply contracts and derivatives that serve markets around the world.

Dubai has been transformed through the addition of new grades, new delivery mechanisms, and new market participants, ensuring that it is fit for purpose in the 21st century’s new marketplace for physical commodities – a market characterized by ever greater diversity of participation, the rising voice of consumers in Asia, and growing volumes of trade flows.

Platts conservative estimate is that there are more than 2.2 million barrels per day (mb/d) of spot crude oil deliverable against the Dubai benchmark, thanks to the inclusion of four grades alongside Dubai itself in the benchmark. And the value of Dubai represents the activity of a broad array of global market participants – equity producers in the Middle East, refiners in

The Evolution of Dubai Benchmark





Asia, and, of course, the physical trading community.

The Dubai benchmark has served the markets well as the basis of pricing long-term sales of crude oil from producers to refiners since the 1980s, used either on its own or alongside Platts' Oman benchmark. Essentially, Dubai helps market participants understand the tradeable value of medium sour crude in the Middle East spot market.

The benchmark reflects the value of medium sour crudes trading in the open market between willing buyers and sellers, without destination restrictions or other re-trading restrictions, for cargoes that will load two, three, or four months after the date of trade itself.

As with Brent and West Texas Intermediate (WTI), Dubai has a strong sense of inherent definition that makes the name Dubai itself a standard and a brand. It generates a clear, flat-price market value for medium sour crude on a daily basis, as well as a vital forward curve both for physical barrels and in the derivatives markets. Its strong inherent meaning has cleared the way for Dubai to overcome the kinds of physical limitations that geology imposes on every raw material.

As with Brent and WTI, Dubai has grown over the years to include delivery of other crude oils beyond loading at Fateh, from the original field itself. As of 2018, the four crudes deliverable alongside Dubai itself are Al Shaheen from Qatar, Upper Zakum and Murban (with a quality adjustment premium) from Abu Dhabi, and Oman Blend.

Since January 2016, when Platts introduced Al Shaheen and Murban in the Dubai benchmark, about 49 per cent of the cargoes declared by sellers to buyers during our Market on Close assessment process have been Upper Zakum, 29 per cent Al Shaheen, and 22 per cent Oman. A single Dubai

cargo was delivered during trading reported through the Platts Market on Close (MOC) during that time, in late October 2016.

We have long maintained at Platts that physical market benchmarks – especially raw materials benchmarks – must work hard to maintain a strong available volume of inherently deliverable material, if they are to remain relevant reflections of market value.

One of the greatest tests of any physical price reference is its ability to evolve with the times, and to surmount challenges like falling production by incorporating new sources of spot supply, new ideas, and new ways of thinking.

This continues to be an important element of Dubai's role as the basis for many official selling prices, tender sales, and other term contract structures. It is also important because Dubai serves as the cornerstone of two key analyses that the markets perform in real time. Paired with Brent, and sometimes WTI, the difference in value between Dubai and Western benchmarks generates an East/West spread which underwrites daily flows of

crude between the Atlantic and Pacific Basins.

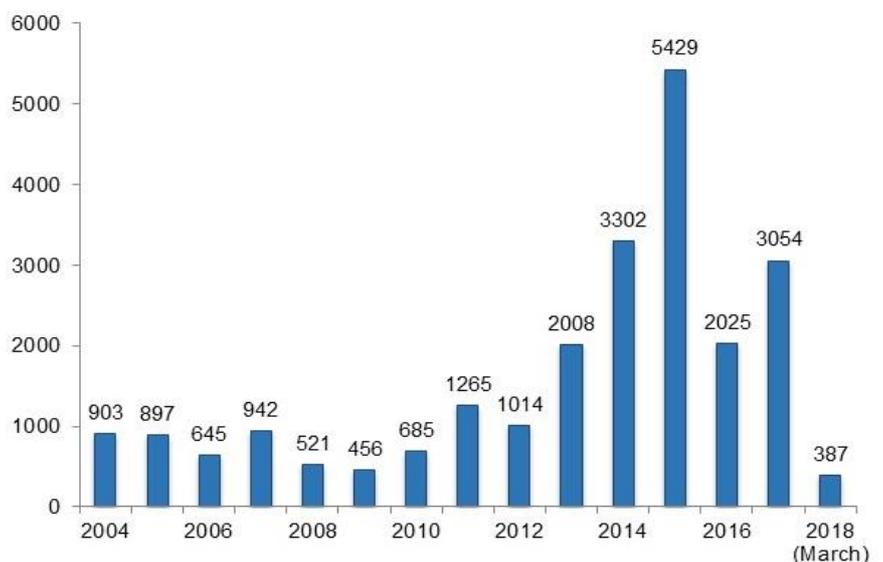
A premium for Brent against Dubai can keep West African crudes circulating in northwest Europe, the Mediterranean, or the US east coast, for example, easing any pressure on Atlantic crude markets. But as that premium comes down, and Dubai's relative value rises, crudes from across the Atlantic, including from the North Sea itself, can more readily flow into Asian markets.

It is no coincidence that as OPEC's production cuts were felt throughout 2017 and into 2018, and the value of Dubai rose steadily in comparison to Brent, flows of the UK crude spread beyond more typical Asian destinations like South Korea and into China.

The physical Brent/Dubai spread moved sharply lower after OPEC's production cuts kicked in in January 2017, trading below \$1 per barrel in January and rarely much above \$2.50 per barrel for most of last year – well below the \$3–5 per barrel spread seen before the cuts.

Crudes pricing in relation to Brent simply became more competitive in Asia as a result, and the relatively high cost of Dubai made crudes pricing in

Trades in partial cargoes reported during Platts MOC (2004–March 2018)





from Russia, the Middle East, and South America’s Pacific coast less attractive to spot buyers.

These same spreads also serve as a gauge of the difference in value between light sweet crudes and medium sour crudes. As key measures of sweet/sour crude economics, fluctuations in the Brent/Dubai and WTI/Dubai spreads can have a major impact on how a refinery plans its slate of crudes – and in turn, can play an important role in how much diesel, jet fuel, gasoline, and fuel oil are likely to flow into spot markets in coming months.

For the interplay between Brent, Dubai, and WTI to function effectively and efficiently, it is important for each point on the triangle to represent as much as possible the actual spot market value of the crude oil each represents – which should be a function of the price buyers and sellers are willing to trade at, with as little impairment as possible from potentially distracting factors like major fluctuations in liquidity, logistical constraints, or unreasonable asymmetry in insight into emerging market conditions.

To ensure our benchmarks meet the mandate, we regularly propose changes and updates to their specifications. In keeping with the spirit and expectations for best practices to be applied by price reporting agencies, like the [Principles for Oil Price Reporting Agencies](#), published by the International Organization of Securities Commissions in October 2012, (Platts publish such proposals publicly in our various information products and on our website). After a comment and consultation period, we go on to confirm the proposed changes – with any adjustments made based on feedback – and then implement them.

The last major set of changes we introduced to our Middle East benchmarks was in late 2015, when we proposed the introduction of Al Shaheen and Murban as deliverable crudes into the Dubai benchmark, and Murban as a deliverable into our Oman benchmark.

Observably, liquidity in the physical markets has grown substantially since the early 2000s, and Middle East crude is no exception. The markets have embraced the introduction of these new crudes, and the regular nomination of Upper Zakum, Al Shaheen, and Oman into the convergence of full cargoes has demonstrated the effective role that each major stream of crude is playing in the benchmark.

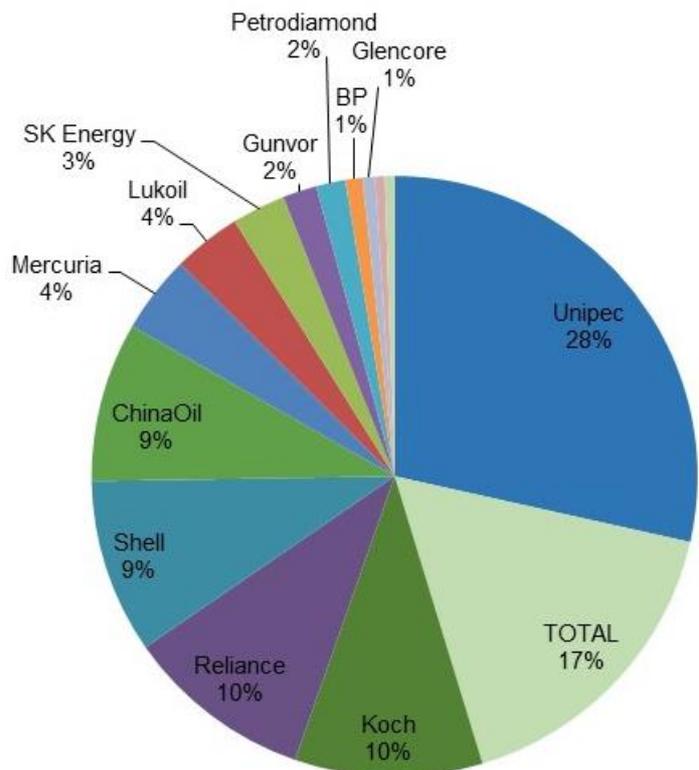
The number of physical partial cargo trades reported during the Platts MOC also shows that the market continues to demonstrate great confidence in the physical market mechanisms reflected by Dubai. As the chart below shows, more than 2,000 partial cargoes are still

traded during the Platts MOC process every year, and the markets are observably deep enough to handle any significant changes in liquidity – increases or falls.

This is important, particularly given that physical market liquidity can rise or fall for any number of reasons. In August 2015, Platts reported on unprecedented volumes of trading in the Middle East’s physical crude oil markets. Looking back, it is clear that relatively low prices for crude oil – crude had fallen to the mid-\$40s per barrel for only the second time since the financial crisis in early 2009 – played a factor in surging physical trading volumes. The emergence of a whole new class of spot market buyer, independent Chinese oil refiners who had to meet import quotas for the first time, were also a factor in the jump in spot market liquidity in the summer of 2015.

Higher volumes have regularly shown that these physical markets continue to grow, and that space must always exist

Participation in Platts MOC process (Q1 2018, trades reported by companies)





for new entrants to be part of benchmark dynamics. The changes we have made to our methodology and specifications for Dubai and Oman help ensure broad participation in the benchmarks from all corners of the market, and help keep Dubai representative of the dynamics in the East/West and sweet/sour trade flows.

As part of our MOC assessment process, Platts publishes fully and transparently the names of all the companies that provide bids, offers, and trades for consideration in our final assessments. These data are published in real time, along with the data as it comes in for publication.

A quick review of partial cargo trades reported by Platts during the first quarter of 2018 shows that 15 companies have traded partial cargoes during the MOC so far this year – a large and diverse group for a spot physical crude market – and that activity is well distributed across these companies. Spot activity by entities from China, India, South Korea, Japan, and Russia are represented in the benchmark, certainly reflective of the energy economy of 2018, alongside western oil majors and international trading giants.

Derivatives markets also continue to respond positively to the evolution of Dubai as a benchmark, with trading volumes in Dubai-settled futures and other exchange-cleared derivatives regularly hitting record volumes throughout 2017.

Our view at Platts is that solid physical market benchmarks are built around three core pillars: the specifications defined for each benchmark, the way data is collected and validated, and the process used to evaluate each day's data and arrive at a final benchmark assessment. While it is impossible to say with certainty what evolutions will follow next for our benchmarks, it is a

certainty that changes will continue to occur, just as the world around us generates changes and new considerations on a constant basis.

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THE DUBAI BENCHMARK: ARE THERE ANY VIABLE ALTERNATIVES FOR ASIA?

Tilak Doshi

Crude oil reference prices in the Atlantic Basin market – Brent Blend and West Texas Intermediate (WTI) – are discovered in futures markets such as the Intercontinental Exchange (ICE) and the CME Group (CME). The reference or 'marker' price for Middle East crudes sold in Asian markets, however, is assessed by price reporting agencies (PRAs). The Oman-Dubai average base price in typical Middle East crude oil sales invoices for Asian customers refers to price assessments published by Platts, a leading PRA and a division of Standard & Poor's Financial Services LLC. Concerns about crude oil price discovery in Asia, and specifically with the assessment methodology for Platts Dubai price quotes, have long been raised by industry journals and the trade press as well as by academics.

Three potential alternatives to the Dubai price assessments published by PRAs have been noted in the trade press on Asian crude oil benchmark pricing: the Oman futures contract traded on the Dubai Mercantile Exchange (DME), ESPO (East Siberia–Pacific Ocean) spot crude sales off Russia's Far East port of Kozmino, and the proposed sour crude futures contract on the Shanghai International Energy Exchange (INE). The Oman futures contract was launched in June 2007, and has since established itself as the key instrument for physical Oman crude oil delivery. However, its estimated average daily traded

volumes of 5,000–6,000 contracts pale in comparison to the daily volume of over 800,000 Brent Futures contracts traded on ICE in September 2016.

The emergence of the DME Oman futures contract as a viable instrument for establishing a reference price for Middle East crude oil exports to Asia is contingent on whether key market participants support the use of that instrument as a mechanism for price discovery. Until a major Middle East national oil company elects to use the DME Oman futures contract price as a price benchmark (replacing the current Oman-Dubai average reported by PRAs), the contract will continue being traded as a tool for effecting physical delivery of Oman crude. For all those with price exposure to Dubai-linked crudes sold on term contracts (accounting for the vast majority of Middle East crude exports to Asia), the ability to shift risk from Dubai to the Brent futures contract is a critical requirement, and the most liquid instrument for that remains the Brent-Dubai EFS (exchange of futures for swaps) contract traded on ICE in London.

DME's ambitions for the contract's wider role as a pricing reference and risk management instrument for Middle East crudes sold in Asia will likely remain out of reach until a major stakeholder or group of stakeholders finds the existing PRA assessments of oil benchmark prices too dysfunctional and unilaterally opts for an alternative. This is precisely what happened in the case of Saudi crude oil sales in the USA. In 2008 and 2009, WTI crude was often disconnected and sold at steep discounts to the Brent global benchmark as a result of logistical bottlenecks at the Cushing (Oklahoma) delivery point. Faced with large revenue losses due to the WTI discounts, Saudi Aramco announced a switch in their price reference in



January 2010 from the Platts benchmark WTI assessments for delivery at Cushing to price assessments by a competing PRA (Argus Media) of an alternative sour crude index. Known as the Argus Sour Crude Index, it is a volume-weighted average of daily spot sales of the three US Gulf Coast medium sour crudes Mars, Poseidon, and Southern Green Canyon.

The completion of the ESPO oil pipeline in 2010 allowed crude oil cargoes to be loaded out of the port of Kozmino in Russia's Far East. Kozmino's proximity to the oil refineries of northeast Asia, within three to five days' sailing time from markets in China, South Korea, and Japan (which account for over half of total Asian demand for crude oil), confers significant locational rents to ESPO Blend crude oil relative to similar-quality crudes which need to be imported from much more distant locations in the Middle East, West Africa, and Latin America. It can take anywhere from two to three weeks to ship oil from these latter locations to northeast Asian ports. ESPO Blend exports from Kozmino led several market observers to suggest that the new crude marketed into Asia had attributes that could lead it to serve as a new pricing benchmark.

Although deliveries of ESPO crude at Kozmino are significant in volume (estimated to be over 0.5 million barrels per day (mb/d) in 2014–2015), sales of the crude away from spot trade in favour of long-term supply commitments and sales via tender to invited participants have limited spot market liquidity. Concerns about concentration on the supply side – with two companies, Rosneft and Surgutneftegaz, accounting for almost three-quarters of ESPO production – also work against ESPO spot trade leading to independent price discovery. On the demand side, when the ESPO

trade out of Kozmino gained momentum from 2010 onward, it drew a wide range of customers (including Australia, Malaysia, Singapore, and the USA) outside of the core markets of northeast Asia (China, Japan and South Korea). In the past two years, however, the list of buyers has narrowed considerably. Effectively, customers from only two countries, China and Japan, are left. As the ESPO Blend draws new supply from different oil fields in eastern Siberia, there are also concerns about the long-term stability of crude oil quality. These concerns, as well as uncertainty over government policy and perceptions that the ESPO market could be influenced by the political considerations of Rosneft, a state-owned company, suggest that the spot trade in ESPO is unlikely to lead to independent price discovery. ESPO crude will most likely continue to be priced off Dubai price assessments.

In 2012, the Shanghai Futures Exchange announced its plan to launch a crude oil contract based on a medium sour crude oil with specific gravity ranging from 30 to 34 degrees API and a maximum sulphur content of 2 per cent. The proposed contract would include the commonly spot traded Middle East crudes such as Oman, Dubai, Basrah Light, Upper Zakum, and Qatar Marine, as well as Shengli, a domestic crude, delivered to specified locations in China. The Shanghai crude oil futures contract was initially planned to start trading on the Shanghai Futures Exchange; but its launch has been repeatedly delayed, and in 2013, the planned launch was moved to a new exchange, the INE, located in Shanghai's new free trade zone. After repeated delays, the yuan-denominated futures contract -- the first Chinese commodities contract to be fully open to foreign investors, a landmark in the opening of China's financial markets with tax incentives and promise of full

convertibility of the yuan – was launched on March 26th. The crude futures contract “kicked off to a roaring start” as western traders and Chinese state-owned companies actively traded the world's newest financial oil instrument. While it may well attain a status as the third global price benchmark alongside Brent and WTI crude, it remains to be seen whether Shanghai's sour crude futures contract can overcome key obstacles. The experience of exchanges launching futures trading is replete with examples of new contracts being launched amid great fanfare only to fail subsequently as the contracts fail to develop sufficient liquidity and slide into irrelevance.

That Asian crude oil markets need a genuinely Asian marker is a popular sentiment even among seasoned market participants. In this view, a shift of crude pricing benchmarks eastward is a natural move given the shift in the centre of gravity in crude oil trading to Asia. A variant of this argument is that the sheer size of China's oil market – importing over 8 mb/d – is enough to justify its own pricing benchmark. The scale of Chinese demand in global commodity markets can indeed lead to rapid growth in domestic liquidity on the commodity exchanges. For instance, the Dalian Commodities Exchange is home to the world's first and third most actively traded commodity contracts (steel reinforcement bars and iron ore). China's efforts to launch a crude oil futures contract seem to be geared towards having their commodity imports priced as much as possible off of Chinese reference contracts. Chinese authorities announced a series of special policies on taxation, foreign currency exchange, and bonded delivery to enable and encourage overseas participation.

The contract size was raised to 1,000 barrels a lot, up from the initial 100



barrels, as a means to reduce volatility by making the contract less attractive to non-oil-related individual speculators. While the development of successful futures contracts requires both buyers and sellers to have confidence in the contract's specifications and in the futures exchange that offers the platform for executing trades in the contract, it is also critical that governments provide an environment conducive to the operation of futures markets. In that context, the sharp sell-off in China's stock market in mid-2015, followed by the government's rushed regulatory shifts to reassert control over the market, raises concerns about the government's commitment to allowing markets to determine prices without administrative "guidance" from government authorities. More recently, actions by the country's National Development and Reform Commission to rein in surging coal prices by administrative fiat again brought attention to the government's reluctance to allow commodity markets to trade freely and openly.

As the largest oil-consuming region in the world, Asia occupies a central place in the planning and analysis of most state-owned or publicly listed corporations in the oil industry. Given that the OECD (Organisation for Economic Co-operation and Development) countries have already reached or will likely soon reach peak oil demand, Asia is commonly seen as the major demand-growth region for oil in the coming decades. In a context of low oil prices and robust production of unconventional oil in North America, the major crude oil producers in West Africa, Latin America, and Russia are aggressively competing with Middle East exporters for market share in Asia. Asian buyers spoil for choice in a buyers' market after almost a decade of high oil prices, now actively look at spot purchases of crude oil from Latin America, the North Sea, and the US

Gulf Coast, apart from their regular supplies from the Middle East, West Africa, and Central Asia. West African crude oil, having dramatically lost market share in the USA with the surge of light tight oil output as a result of the shale revolution, now faces static demand in Europe and an imperative to compete in Asia for incremental demand alongside other crude oil producers.

Crude oil pricing benchmarks are the outcome of market evolution rather than government policy. The status quo in Asian oil markets, where the pricing benchmarks are discovered by PRAs, has shown resilience and a longevity that may seem surprising to some observers. But an appreciation of how the Dubai benchmark works as an integral part of global oil market price discovery and risk management goes a long way in explaining the robustness of the Middle East crude oil pricing norms. It should be noted in particular that the Dubai reference price is effectively linked to the highly liquid Brent benchmark by the Brent-Dubai EFS contract, one of the most actively traded derivative oil contracts, allowing those with Dubai price exposure to hedge their risks.

Unlike the Atlantic Basin, where crude reference prices (Brent and WTI) are discovered in liquid futures exchanges such as ICE and the CME, the Asian market does not have any traded futures contract for crude oil which serves as a widely used pricing benchmark for sour crude. The reference Dubai crude price is, as already noted, discovered by PRAs such as Platts and Argus Media. While the role of PRAs in oil price discovery has been the subject of considerable debate and controversy, there seems to be no plausible alternative. The current system of voluntary reporting of trades, bids, and offers to PRAs, evolved since the mid-1980s at the end of the OPEC

administered-pricing system, has proved resilient despite the many deficiencies emphasized by market observers.

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MIDDLE EAST POISED TO JOIN THE RANKS OF TRADING HUBS

Paul Young

Casual observers might easily be lured into thinking that the USA, boosted by its 7 million barrels per day (mb/d) shale oil bonanza, is the now at the centre of global crude oil production. But they would be wrong; that accolade still belongs to the countries surrounding the Middle East Gulf.

The US oil and gas industry has done a tremendous job in boosting the nation's output to a five-decade high, but the Middle East is still, and is likely to remain – by any key metric, whether production, reserves, or exports – the crude oil kingpin.

The USA has, however, been years ahead of the Middle East in terms of trading and pricing, especially with its flagship West Texas Intermediate (WTI) crude benchmark, accompanied by the highly liquid gasoline and distillate futures contracts hosted by CME Group (CME).

Ready for change

The Middle East Gulf and (to some extent) Asia have struggled in terms of market development due to their conservative approach to hedging and more forward-looking pricing strategies. The USA and Europe have a more natural balance of buyers and sellers, which provides the core liquidity for WTI and Brent futures and associated products. The natural longs and shorts in the market will place both short-term and long-term hedges, which helps smooth out price volatility. For instance, a refiner buying unhedged crude oil and selling refined products from the crude



two months later could end up selling gas oil below the purchase price of the crude.

The ‘it all balances out in the end’ attitude, though, has largely disappeared, and a number of Asian refiners operate sophisticated hedging strategies to help smooth out market fluctuations and manage cash flow more efficiently – particularly those in China, India, Singapore, and Japan.

National oil companies in the Middle East are also increasingly adopting this model and have refocused marketing arms into fully fledged trading companies, which will be a key development in shaping the region into a fully fledged trading and benchmarking hub.

Oman led the way, establishing Oman Trading International and Vitol in 2006, coinciding with the formation of the Dubai Mercantile Exchange (DME). Saudi Arabia established Aramco Trading Company in 2010, and more recently, Iraq’s SOMO (State Organization for Marketing of Oil) and Russian trading giant Lukoil have formed a joint-venture company, initially focusing on crude oil but expected to move into refined products. At least two other Gulf states are said to be in advanced negotiations to branch into trading and hedging.

These developments are a significant step in changing the mindset of the region as it develops from a price-taker into an integral participant in price formation and discovery.

Oman crude oil benchmark

Oman is the single most important grade in the Middle East when it comes to price discovery and trading, not only in terms of futures contracts but also as a key part of the Dubai pricing mechanism; it is expected to play an integral role in Shanghai’s International Energy Exchange (INE) crude contract, which launched in March 2018.

Oman’s Ministry of Oil and Gas (MOG) adopted exchange-based pricing in 2007 and uses the DME pricing as the basis for its monthly official selling price (OSP) calculation. The weighted average of the daily five-minute pricing window will be averaged out over the month, enabling both buyers and sellers to hedge on a forward basis. Typically, several million barrels will change hands during the pricing period, providing a solid basis for a benchmark price.

The grade is the largest freely traded crude stream in the region, with a production capacity close to 1 mb/d and exports of around 0.8 mb/d. Oman is a popular grade in Asia among both refiners and traders; not only is it the only east-of-Suez crude backed by a futures contract, but it is also extensively traded in the secondary over-the-counter spot market, which leads to delivery chains between futures and over-the-counter in much the same way Dated Brent is traded.

The delivery chains have paved the way for DME Oman to establish itself as the largest physical delivery of any commodities contract in the world, with typically 25–30 million barrels going to delivery on contract expiry each month. Enhancing Oman’s reputation as a key benchmark is the broad level of participation, with around 90 active traders each month and a healthy mixture of refiners, trading houses, international oil companies, and financial entities. Typically no single entity conducts more than 10 per cent of DME trading activity in any given month, which again adds to market confidence in the benchmark.

Destination Asia

The vast majority of incremental oil demand this century has come from Asia, so it is no surprise that China has a voracious appetite for Oman crude, regularly consuming over two-thirds of the entire monthly export program.

However, with Chinese refiners enjoying a much greater choice of crudes these days, Oman is finding a broader range of end receivers. In the first two months of 2018, Oman crude was shipped to nine countries – China, India, Japan, Malaysia, Myanmar, New Zealand, Singapore, South Korea, and Taiwan – while 2016 and 2017 saw the occasional arbitrage open up for Oman crude into the USA. Around 40 separate entities lift Oman crude, and many end users are buying from third parties rather than directly from the MOG or DME.

Oman’s Mina al Fahal loading port enjoys the advantage of being east of the strategically sensitive Strait of Hormuz, which connects the Middle East Gulf with the Gulf of Oman and beyond. The US Energy Information Administration (EIA) calculated some 18.5 mb/d of crude and refined products were shipped through the Strait in 2016, representing around 30 per cent of all seaborne oil and liquids trade and making it the most important chokepoint in global energy trading.

The EIA estimates that at least 80 per cent of crude oil shipped via the Strait of Hormuz is destined for Asian markets, with refineries in China, India, Japan, Singapore, and South Korea the largest buyers.

China joins the exchange world

When it comes to crude oil futures, the USA has WTI, Europe has Brent, and the Middle East has Oman. East Asia had nothing until 2018, when the Shanghai-based INE launched its long-awaited medium sour crude contract, of which Oman will be a major component. Oman already enjoys a strong correlation with Dubai prices and is expected to have a similarly close correlation with the INE crude contract. But while Oman and Dubai are based on FOB Middle East, the INE contract opens up a whole new market for spread trading between the value at



export point and the value at consumer location.

Essentially the spread will represent the Middle East price of crude versus the delivered price of crude into East Asia, which is likely to appeal to traders and refiners alike. Before the USA and North Sea went their separate ways on fundamentals, the Brent price was typically the netback value of WTI – but since the Cushing delivery point was swamped with crude, Brent has typically traded at a premium to its US counterpart.

Shanghai's initial liquidity is likely to come from the domestic Chinese market; but going forward, the contract is expected to have a much wider international appeal, and spreads like WTI/INE and Oman/INE are likely to become established crude oil price markers.

DME auctions

Another innovation in crude oil marketing among national oil companies is the DME auction platform, which has brought new levels of transparency to what are typically very opaque spot markets. Selling via auction not only guarantees best-available price for sellers but also allows sellers to gauge the market strength in setting OSPs.

Oman's MOG was the first adopter of DME auctions in 2016 and has since been a regular seller of additional spot barrels via the auction process – particularly when Oman's two domestic refineries undergo scheduled maintenance.

More recently, SOMO has proved to be the unlikely champion of change and innovation in the region, regularly listing both Basrah Heavy and Basrah Light on DME auctions and selling 24 million barrels on the platform during 2017. SOMO has also engaged in extensive dialogue with customers on OSP methodology.

Malaysia's Petronas was the first Southeast Asia producer to utilize DME auctions, selling 500,000 barrels of Kimanis crude oil. Over 50 companies have now registered for DME auctions.

Middle East potential for refined products

The Middle East has seen a huge expansion in refining capacity to above 10 mb/d, and while much of it is used to supply soaring domestic demand, the region is increasingly a swing supplier of a number of refined products, including LPG (liquefied petroleum gas). Leading consultancy FACTS Global Energy (FGE) predicts that the Middle East will be net long products to the tune of 4 mb/d by 2020 and notes that even gasoline, where the Middle East has been net short since the turn of the century, will have a small oversupply by 2020.

But it is likely to be distillates that give the Middle East an edge when it comes to trading opportunities, as the healthy surplus increasingly puts the region in the position of swing supplier. FGE predicts the Middle East will have a net balance of around 1.7 mb/d diesel/gas oil and jet/kerosene by 2020, supplying both Asia and Europe, with Saudi Arabia the largest contributor following extensive new refining projects. In particular, around 60 per cent of jet exports go to Europe, so the old Singapore netback model for Middle East pricing will become increasingly broken, creating a need for stand-alone regional pricing.

The upcoming International Marine Organization (IMO) 2020 legislation will lead to a radical shake-up in the market, as 0.5 per cent sulphur gas oil replaces the soon-to-be prohibited 3.5 per cent sulphur fuel oil in the shipping market. This will likely produce an excess of heavy fuel oil needing expensive sulphur-reducing treatment, and on the flipside, a shortage of diesel. Already traders are talking about

huge swings in relative spreads between gas oil and fuel oil. Such jolts to the market are typically agents of change, so rather than attempt to manage prices against netback models that are no longer fit for purpose, the industry is likely to rally around new and more relevant benchmark pricing for the Middle East.

Traditionally, the Middle East has been at a disadvantage to other trading hubs due to a lack of third-party storage, but Fujairah has solved that problem with its 10 million cubic meters and growing commercial storage. As such, Fujairah is likely to be the focal point of benchmark pricing going forward.

Middle East tipped for the top

Overall, the position of the Middle East oil industry is looking very healthy. The Saudi-lead OPEC policy since 2016 has put the region on a more balanced financial footing, and a number of key regional events are planned. Dubai will host the prestigious 2020 Expo, followed by the United Arab Emirates' 50th anniversary in 2021 and Qatar's hosting of the 2022 football World Cup.

By that time, the Middle East will be well and truly established as a world-class trading hub.

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CHINA'S CRUDE AWAKENING

Michal Meidan

On 26 March 2018, the Shanghai International Exchange (INE) officially launched its long-awaited crude futures contract. Much ink has been spilled about the rise of the INE crude contract, namely whether it will join (and ultimately displace) Brent and West Texas Intermediate (WTI) as the leading global crude benchmark and whether the renminbi (RMB)-traded contract signals the end of dollar dominance in trading. The short answer to both questions is no, but the launch



of the contract – after years of planning and numerous false starts – is nonetheless momentous as China tries to take more control over crude oil pricing.

The fear, of both international traders and the government, has been that retail investors, seeking avenues to place funds in a market with tight capital controls, will generate significant volatility, only to be tempered by government regulators fearing that trading is getting out of control. Yet at the time of writing, speculative activity has been relatively muted. What is more, since these retail investors have limited ability to hedge on the international markets, any speculative spikes will likely remain a contained domestic phenomenon. The first big test will be the first contract expiry and physical delivery in September 2018; but with numerous details still being ironed out, participants on the physical side will consist mainly of the Chinese majors and a handful of large international traders. Nonetheless, over time, the INE contract will be fine-tuned and could, at the very least, become the domestic benchmark for Chinese refiners.

Why a Chinese futures contract?

The need for a domestic Chinese crude benchmark has long been discussed in Beijing. The Chinese economy has grown at an average rate of 10 per cent for almost four decades and is now the world’s second largest economy. In 2017, China also surpassed the USA to become the world’s biggest importer of crude oil, at 8.4 million b/d (mb/d) compared to 7.9 mb/d for the USA. Yet despite China’s increasing prominence in the global economy and trade, the financial system is still dominated by the dollar, the

euro, and the yen, while the benchmarks that determine prices for the crude China purchases are in the North Sea, Cushing (Oklahoma, USA), and Dubai. The Shanghai crude futures contract, announced over five years ago, seeks to remedy these shortcomings and establish a benchmark that will better reflect supply and demand dynamics not only in China but in the Asia Pacific more broadly, especially since Brent and WTI represent predominantly light-sweet grades while Asian buyers typically consume a larger share of Middle Eastern medium-sour crudes. From a domestic perspective, private refiners and traders hope that the contract will weaken the state-owned majors’ control over pricing.

A contract with Chinese characteristics

In the government’s eyes, the Shanghai contract is therefore part of China’s natural progression from a price taker to a price maker in global oil markets. Shanghai’s RMB-denominated, physically settled contract aims to reflect the lowest-priced grade of a basket of mainly Mideast Gulf sour crude. Upon launch, it listed seven monthly contracts covering September 2018 through to March 2019, and

quarterly contracts out to March 2021. But since the first physical delivery will not occur until September 2018, the first contract will remain on the board for several months to attract more participants, ahead of its expiry on 31 August. Trading hours are currently limited, with little overlap with Western markets; but over time, the INE will seek to extend them (see Figure – Terms of the INE crude futures contract).

Seven grades are to be delivered into the contract including Upper Zakum, Dubai, Oman, Qatar Marine, Yemeni Masila, Iraqi Basrah Light, and domestic Shengli, with the minimum volume accepted for delivery set at 0.20 million barrels (mb), equivalent to 200 lots.

Before expiry, traders will be able to cash settle their positions with physical delivery or through an exchange for physicals. For physical deliveries, the INE has designated eight storage tanks, with active capacity of 19.8 mb (the total approved capacity of these tanks is 37.4 mb), all run and owned by the majors (see Fig 2), and an additional three backup tanks. The exchange will calculate freight and associated costs (including loading fees, delivery commission fees, and

Terms of the INE crude futures contract

Contract terms	
Contract size	1,000 barrels/lot
Price quotation	RMB per barrel
Daily price fluctuation	Capped within a 4% range of the previous days' settlement price
Trading hours	9.30-11.30 am; 1.30-3.00 pm; 9 pm - 2 am Beijing
Last trading day	Last trading day of the month prior to the delivery month
Delivery period	Five consecutive business days after the last trading day
Deliverable grades	Basrah light, Dubai, Upper Zakum, Masila, Oman, Qatar Marine and Shengli
Benchmark specifications	32 API; 1.5% sulphur content
Delivery method	Physical delivery
Settlement method	RMB, conversion of profits to USD possible

Source: INE, Energy Aspects



inspections fees) to derive a delivered cost for each new contract. Finally, profits can be settled in RMB or dollars – and the rumoured settlement in gold is currently not an option – but losses made on positions can only be settled in RMB.

A crude question

The choice of crudes has raised questions given that grades from China’s largest suppliers – Russia, Saudi Arabia, and Angola – are not represented in the contract. Supplies from Yemen and Qatar, however, only accounted for 31,000 and 20,000 b/d, respectively, of China’s imports in 2017. Intakes of UAE grades averaged 0.20 mb/d that year, leaving only Omani and Iraqi crudes, which accounted for 0.62 mb/d and 0.74 mb/d of Chinese crude imports in 2017, as realistically deliverable grades. Shengli is also an intriguing choice given that it is a domestic grade, and it is priced a month in retrospect, so the government and Sinopec will now need to work on changing the pricing mechanism for it.

To add to these complications, the INE has announced a discount of RMB 5/Mt or \$0.10 per barrel to Basrah Light and Shengli crude, and a premium of \$0.10 per barrel to Yemeni Masila Light (with no modifiers to Upper Zakum, Dubai, Oman, or Qatar). It is unclear if and

how frequently these modifiers will be revised, but the INE has stated that it will take into account the quality differences and spot market spreads between them as well as additional information related to these crude streams. Moreover, Shengli delivered into the contract could be exported from the bonded storage tanks used for delivery, further complicating pricing calculations.

Let’s get physical

Storage space is an additional concern for both foreign traders and independent refiners looking to deliver into the contract. The tanks are owned and run by the majors, and storage costs have been tentatively set at around \$1 per barrel. Independent refiners therefore fear that they will struggle to find storage space when they need to settle a position, even though the INE will match up the crude to tanks and will determine delivery points depending on quality (as they have said there will be no blending) and availability. The INE has also stated clearly that as long as the storage facilities are not fully occupied, the majors cannot inhibit deliveries. But this leaves much to the majors’ discretion.

Moreover, the tanks are dotted all along the Chinese coast, spanning 2,700 km from Dalian in the north to Zhanjiang in

the south, but there are no differentials attributed to their location. So buyers wishing to bring the crude from the tanks into onshore storage or a refinery will need to hire a Chinese tanker to move the barrels from the INE-designated tanks, incurring additional costs. The associated fees – including loading and discharging, port security charges, inspection fees, and commission of delivery – at Cezi in Zhoushan, for example, are currently estimated at \$0.30 per barrel, compared to \$0.50 per barrel at Zhanjiang. Additional tanks as well as privately owned facilities could still be designated at a later date.

Finally, the only parties that will be able to bring physical cargoes into China are licenced importers (the majors, which have unlimited rights to import crude and resell it in China) and the small ‘teapot’ refineries that have received import licences. Unlicensed traders will have to resell to a licensed Chinese buyer or re-export. In light of these limitations, the contract will need to trade at a significant premium to Dubai in order to take off. At the outset, therefore, foreign traders could use it as a storage play in Asia, but with under 20 mb of storage space available and current market structure, even this storage play will only be marginally appealing. For now, the Chinese

Designated storage tanks, mb

Location	Storage name	Operator	Approved capacity	Active capacity
Dalian, Liaoning	Dalian PetroChina bonded depot	PetroChina	7.2	2.5
Zhanjiang, Guangdong	Zhanjiang Branch	PetroChina	4.4	2.5
Cezi island, Zhejiang	Cezi Island Reserve	Sinopec	5.0	3.8
Aoshan, Zhejiang	Sinochem Xingzhong Aoshan Depot	Sinochem	6.3	2.2
Yangshan, Shanghai	Yangshan Depot	Yanghsan Shengang	1.9	1.3
Rizhao, Shandong	Rizhao Base	Sinopec	7.5	2.5
Daxie, Ningbo	Ningbo Daxie branch	PetroChina	2.5	2.5
Qingdao, Dongjiakou	Qingdao port, Dongjiakou	Qingdao port	2.5	2.5
Total			37.4	19.8

Source: INE, Energy Aspects



majors will likely be the key participants in the physical market.

The rise of the petro-yuan?

Another issue for foreign trades is currency. Beijing is seeking to encourage greater use of RMB in cross-border trade and to make it easier for Chinese and international companies to do business in RMB. There have been suggestions that China is using RMB to buy cargoes of oil from countries like Russia and hopes to do the same with Saudi Arabia, but RMB have still been converted into US\$ for the vast majority of transactions. If the INE futures contract is liquid and transparent enough, having significant volumes of oil priced in RMB will impact global markets, but this is still some way off and would depend on international banks holding significantly more RMB reserves and producer countries being willing to source more goods from China and pay for them with RMB. Even so, the government’s penchant for currency controls and intervention in the country’s stock markets would still act deter many.

China’s independent refiners find the notion of an RMB-traded futures contract appealing, as they could hedge their financial risk by buying oil in their own currency rather than in dollars. However, they would also like to see foreign companies delivering into the contract; so for now, most have opted to sit on the sidelines and see how trading unfolds. Foreign traders have dipped their feet in cautiously and will likely become more active participants over time. Indeed, state-owned trader Unipet announced a deal to buy Middle East crude from Shell priced against the INE contract on the first day of trading. Details of volumes and grade have yet to be published, but even very limited volumes send an important signal. In order to encourage additional instances of crude purchases

priced against the contract, the government also announced that it will waive income tax for overseas investors and brokers trading the futures contract.

To speculate or not to speculate?

In the first months of trading, all eyes will be on the Chinese retail investors. Indeed, the INE reported that 10,000 accounts were opened in late 2017, almost 70 per cent of them by retail investors. Asset managers (likely Chinese) accounted for an additional 10 per cent, leaving few companies with physical oil exposure in the mix. But if the simulation run by the exchange in December 2017 is any indication, investor appetite for the contract is huge. A total of 90,564 trades were made, with 647,930 traded lots and a turnover of RMB 268 billion (\$40 billion). While speculative activity drove the price of Chinese crude futures up as soon as the starting pistol was fired, with 20,000 lots changing hands in the first two sessions of the day, prices fell subsequently. And in its first month, contrary to many expectations, prices on the INE have roughly tracked the Basrah Light OSP and did not surge on speculative buying as many had feared.

Indeed, conscious of Chinese day traders’ eagerness to trade anything from dates to iron ore, the INE has intentionally designated relatively large lot sizes for crude futures (compared to metals, for which small lot sizes and low entry barriers act to encourage small day traders) and introduced a more rigorous registration process, alongside relatively high transaction costs and margin requirements. The INE has also set strict daily limits on the number of cancelled orders allowed per account, to avoid speculators placing bids to buy or offers to sell futures contracts with the intent to cancel them before execution. But importantly, while Chinese retail investors are unlikely to

hedge their domestic contracts internationally and will only likely bid up prices domestically, it will be trades made by the Chinese majors and foreign traders that will be impactful for on global benchmarks and physical flows into China. Indeed, the arbitrage opportunities between the INE contract price and international benchmarks will be exploited by trading companies.

Over time, the INE is likely to fine-tune the contract, leading more refiners and traders (both Chinese and foreign) to trade it. Indeed, many independent refiners and domestic trading companies hope that the INE will become a means of breaking the majors’ dominance of domestic crude pricing or at the very least become a benchmark for product prices, displacing the current government-set formula. The Shanghai Futures Exchange (SHFE) metals contract, after several years of trading, ended up becoming the domestic benchmark and displacing the London Metal Exchange (LME), and since China accounts for over half of global metals demand, the spread between SHFE and LME is now actively traded. But this will be a protracted process for crude, as China accounts for only 10 per cent of global crude demand, and the contract will need to establish options and linkages to a number of existing benchmarks. The launch of the INE futures contract is therefore an important milestone, but it will take years before it becomes a domestic benchmark, let alone a global price-setter.

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CHINA'S NEW CRUDE OIL BENCHMARK: LONG IN THE MAKING, BUT STILL IMPERFECT

Tracy Liao, Edward Morse, Anthony Yuen

Much local hype surrounds the new Chinese crude oil contract becoming both an Asian and global pricing benchmark, in the hope that the Chinese yuan renminbi (RMB) could become the world's main petro-currency. The contract started trading on 26 March on Shanghai's International Energy Exchange (INE). The deliverable crude is a mix of six Mideast and one domestic stream, all medium sour grades but none with vibrantly active spot trading.

Some Chinese authorities believe that establishing a crude contract could eliminate the Asian premium and help reflect pricing of medium sour crudes in the global market. The government also looks to encourage RMB internationalization and increase foreign participation in China's financial and commodities markets.

Successful crude price benchmarks share a number of characteristics: high physical trading volume, consistent quality, security of supply, diversity of market participants, and broad acceptance. The contract appears to satisfy some of these criteria. The Dalian iron ore contract might serve as a good precedent for the Chinese crude contract.

Although the Chinese government and Shanghai exchange worked to address concerns about the contract, a number of mostly made-in-China issues are likely to impede its international success. Its domestic success, on the other hand, is virtually ensured. A history of Chinese regulatory intervention in markets and cross-border capital movements makes market participants worry that policies,

rather than fundamentals, will drive pricing.

Domestic speculators are likely to add tremendous liquidity and potentially destabilizing volatility to trading. Chinese investors are eager to trade, as seen in surging activity in other commodity futures markets there.

Foreign participants generally take a wait-and-see approach despite the exchange's offering settlement in US dollars (USD). The integrity of a commodities contract is at risk if there is rampant speculative activity in the paper market or manipulation in the physical market. Both elements could well be present, as investors in China are highly speculative and trading arms of Chinese majors will have a substantial presence in the exchange. There is also no apparent way to link the contract to the broader oil trading market, such as having an Intercontinental Exchange (ICE) look-alike that traders can arbitrage with other crude contracts also on the platform. Hedgers may also not be able to use it reliably for now to hedge their delivery price risk instead of using the Dubai Mercantile Exchange (DME) Oman crude.

If and when China can resolve these trading and regulatory issues, there could be stronger international interest, but obstacles would still remain.

What the contract looks like

The contract has already started to trade on the INE, with deliverable crudes set to be a mix of medium sour grades with an overall API gravity of 32° and sulphur content of 1.5 per cent. This is similar to Dubai crude, which has about 31° API gravity and 2 per cent sulphur. Deliverable crudes include Dubai, Upper Zakum, Oman, Qatar Marine, Masila, Basrah Light, and the domestic crude Shengli. Delivery points are in four locations across China: the Liaodong and

Jiadong Peninsulas in northeast China, the Yangtze River Delta in the east, and the Pearl River Delta in the south.

The exchange is located inside the free-trade zone in Shanghai, which is structured to allow foreign participants to trade the crude contract in USD with certain restrictions. Foreign market participants are allowed to use USD to post margins in lieu of RMB and are guaranteed currency convertibility, but they are only allowed to retrieve payoffs, including those via physical settlement, in the same currency that they selected for margin deposit, so as to avoid obvious capital outflow. Domestic participants can only use RMB (CNY, the onshore currency, and not CNH, the offshore currency) for oil trading.

For now, a foreign entity can participate by dealing with an exchange member registered inside China, or through an intermediary outside that directly deals with an exchange member registered inside or outside China.

The exchange imposes a 4 per cent daily limit on price movements, and the limit is reset on the second day – that is, if price moves exceed 4 per cent again on day 2, the limit is reset at 7 per cent. If 7 per cent is exceeded on day 3, the limit is reset at 9 per cent. In comparison, West Texas Intermediate (WTI) has a tiered system that halts trading for every additional \$5 per barrel change over the previous day's close, until the price move reaches \$20 per barrel within the same trading day. ICE Brent and DME's Oman crude have no such restrictions.

To ensure participation, the Chinese exchange has mandated certain local players to trade. Different entities under the same corporate umbrella can participate in the exchange, as long as there is no centralized control over the trading activities of these subsidiaries.



Rationales for the contract: to increase China’s influence in oil price determination and promote RMB internationalization

China and a number of other Asian countries have expressed frustration at the perceived Asian premium in energy prices. Some believe that establishing this crude contract can eliminate the premium and make the price discovery process more transparent in Asia, as energy pricing is dominated by exchanges in North America and Europe, despite surging demand in Asia. Even Oman and Dubai crudes, based in the Middle East, do not form a fair benchmark given the way exporters from the Middle East impose complicated formula largely based on FOB (free on board) rather than on delivered basis.

It is important to distinguish between regional pricing power and having prices more accurately reflect regional fundamentals. Prices should reflect market supply and demand. Futures contracts that have ample liquidity should more accurately reflect regional fundamentals, but not accord additional pricing power over the benchmark to the host country.

Some also believe that there is no benchmark that reflects the predominance of medium-gravity sour crudes in the global market. Brent and WTI are both light and sweet crude streams, while Oman/Dubai, traded in Dubai, and Urals, traded in St. Petersburg, have limited liquidity. As a massive importer of medium sour oil, Beijing believes that a local price benchmark is warranted, even though Oman crude is already traded out of the DME in the Mideast.

Nevertheless, even without an active and domestically traded crude futures contract, Chinese trade flows already have a significant influence on global oil prices. The main transmission mechanism is through physical crude

buying and increasing activity in the Brent and Dubai pricing windows by Chinese traders.

The push to have foreign participation in the crude oil contract also follows from the broader government objective of increasing foreign participation in the country’s financial and commodities markets. Increased foreign participation should help increase competition and promote deeper and broader market reforms.

RMB internationalization might remain a stumbling block for a while. The dual use of the USD and RMB for foreign entities trading in China’s crude futures market is another way of encouraging RMB internationalization, but large obstacles remain. Beijing is frustrated that despite the country’s major position in world trade, the RMB does not count among the seven main trade settlement currencies – the US dollar, euro, yen, UK pound sterling, Swiss franc, Australian dollar, and Canadian dollar are all used more often than the RMB, whose use might actually have fallen recently.

Beijing’s push in the INE follows its promotion of the yuan in trade settlement along with the One Belt One Road initiative. The crude contract will likely take time to develop, during which the RMB could increasingly be adopted as a currency of choice, not only in the crude oil trading sphere but more broadly in global trade, although it is hard to imagine this occurring without full currency convertibility.

Key success factors of established crude contracts

Establishing a successful crude benchmark requires meeting a number of preconditions to assure liquidity, consistency, and competitiveness and generate market confidence:

- High volume: A sufficient amount of oil is available to be

traded, with a multiplicity of both sellers and buyers.

- Consistent quality: Buyers are certain that they can buy, resell, and use the oil without a loss in value for quality reasons. If the quality changes, the mix of products refined would be different.
- Security of supply: A sufficient amount of oil is available consistently over time.
- Diversity of market participants: Pricing is competitive, without anyone having outsized market power to distort pricing.
- Broad acceptance: The market is confident that the crude is widely accepted as representative of its grade and location.

Brent in the early 1980s exhibited all these qualities. When volume started declining, other crude streams were added – initially two streams of similar quality, Forties and Oseberg, which created the Brent-Forties-Oseberg construct to bolster the overall volume, with the Ekofisk grade added later to form Brent-Forties-Oseberg-Ekofisk.

WTI also exhibits these qualities. At first glance, it did not appear to be a good global benchmark because of its landlocked nature. But its tremendous liquidity, with huge futures trading volume behind it, helped to overcome its challenges. The New York Mercantile Exchange chose WTI mainly for operational reasons. The extensive pipeline network ensured a diversity of supply domestically, while allowing the movement of small amounts of crude that matched the delivery size of the contract.



WTI's huge volume and liquidity allowed the market to quickly price changes to fundamentals, thereby creating greater price transparency. But despite WTI's prominence globally, its prices can depart significantly from other global crude grades because of pipeline and export constraints. The Brent/WTI spread widened to nearly \$30/bbl earlier this decade because of such constraints.

Asia does not have a good benchmark for a variety of reasons. Dubai comes close, though trading is still much lighter than Brent and WTI. Malaysian Tapis and Indonesian Minas are geographically within the Asian market, but the small volume of production and spot sales, with a few companies controlling production, has limited their effectiveness.

The Dalian iron ore contract

China's Dalian iron ore contract might serve as a good precedent for the Chinese crude contract. The contract, set up in the world's largest iron ore importing and consuming country, attracted substantial domestic liquidity following its launch in 2013. Similar to the Shanghai oil contract, the Dalian iron ore contract allows physical delivery of a wide range of iron ore products, from the 65 per cent Carajas fines to the 61 per cent Roy Hill fines, with premiums and discounts assigned to most of the deliverable products.

Trading patterns in the Chinese crude contract could mirror those of the iron ore contract, such as substantial speculative retail flows and dislocations between prices of contracts upon settlement and actively traded contracts. Daily trading volumes of Dalian iron ore have been consistently higher than open interest over the past two years due to substantial speculative flows and high-frequency trading activity. When a contract enters physical delivery month, prices are usually set by the availability of the

cheapest deliverable products, considering rules on premiums and discounts, with pricing disconnects between contracts.

On the one hand, the Dalian contract may have been leading its offshore counterpart, the Singapore Exchange (SGX) iron ore swap contract, in price discovery over the past few years. On the other hand, China's increasing pricing power on iron ore rests primarily on its predominance as the world's largest consumer at 70 per cent of seaborne imports. This would have happened without the Dalian contract. For oil, China accounts for only 10 per cent of the world's demand despite being the largest crude importer.

Iron ore also enjoys a few characteristics not quite applicable to crude oil. The Dalian iron ore contract has benefitted from a lack of established contracts globally, but Brent, WTI, and Dubai/Oman are well established. The Chinese iron ore market has a wide range of participants, including large steel mills and physical trading houses, and balanced hedging flows that have helped boost liquidity. Iron ore physical liquidity is also currently ample at Chinese ports; a decent proportion of wide range of iron ore products are qualified for delivery into the Dalian contract. The iron ore contract attracts liquidity from similarly actively traded steel and coking coal contracts, which enable market participants to perform relative-value trades. On oil, some expressed interest in arbitraging the crude contract and onshore petrochemical contracts including Polyvinyl chloride (PVC) and polyethylene (PE), but ideally market participants would like to trade crude with other petroleum products, such as gasoline and diesel, instead.

Issues this contract confronts and potential mitigating measures

Despite Chinese authorities' efforts to

encourage foreign participation in the Shanghai crude contract, challenges remain. The success of the crude contracts requires participation by a broad range of producing and refining companies that engage in hedging and can provide or take physical delivery as settlement.

At first glance, the INE contract appears to possess some of the success factors listed in the previous section, except for broad acceptance. On the one hand, there is likely to be significant participation by locals, but the majority of participants are not likely to be from the corporate world – except that some early success here is possible given mandated local company participation. Authorities have also worked to mitigate issues raised earlier, such as currency convertibility, although limitations on full convertibility are likely to be severe. On the other hand, it is not clear how workable the contract pricing is likely to be, as the lowest price of the six crude streams from the Middle East and the one from mainland China should prevail on the exchange. Most of these seven crude streams also have no well-recognized market-based spread among them. Certainly the quality of these crude streams looks largely consistent, at least for the Middle Eastern grades.

But the Chinese crude stream also raises flags. A concern for foreign traders is whether pricing would be distorted by production and shipments out of the Shengli field, which has no clear market relationship to the Middle East crudes. Supply disruptions would not have severe consequences if only one crude stream were affected. On the other hand, diversity of suppliers of Middle Eastern crude, let alone buyers, is an illusion. The suppliers are mainly Mideast national oil companies who determine their own prices via formulae and largely contractually limit resale of their crude. Domestic players, even



including small ‘teapot’ refiners, are limited in number and are fairly lumpy buyers in the local market.

Participants outside of China have generally taken a wait-and-see approach, as the INE contract also faces more unique circumstances brought about by historical regulatory uncertainty and existing barriers to foreign participation. The contract’s use in hedging is questionable for now, as DME Oman (also a medium sour contract) plus transport is available as an alternative. Ultimately, a robust physical underlying spot market is important for the success of the exchange, as the contract should be a mechanism for risk transfer between participants: suppliers looking to hedge deliveries and buyers looking to hedge purchases, with speculators also providing liquidity.

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PETROYUAN VS PETRODOLLAR: A NEW WORLD ORDER?

Antonio Merino & Roddy Graham

Over the last few weeks there has been a lot of hype about the new Chinese crude oil futures contract launched by the Shanghai International Energy Exchange. Many experts have heralded this as a world-changing event, with headlines predicting a shift in the global financial system that could threaten US dollar hegemony.

Oil markets have until now been dominated by two benchmarks: the US West Texas Intermediate (WTI) and Europe’s Brent crude. WTI is the main benchmark for US crude grades, while Brent, priced off North Sea oil, is the primary reference for Europe, Middle East, and African crudes. Both are used extensively by industry and financial traders.

A yuan-denominated crude oil futures contract has been promised for 25 years. In 1993, China tried to develop a local oil futures contract, but it was stopped just over one year later due to high volatility. The price fluctuations were so great that hedging by using the contract actually became more risky than not hedging.

China is now the world’s largest buyer of oil. It accounts for more than 25 per cent of Asian demand and over 10 per cent of total global demand. Therefore, China has an interest in using its own currency rather than that of a geopolitical competitor.

So far, the Chinese authorities have not pushed the new oil futures contract heavily, like they did to get the yuan into the International Monetary Fund’s basket of official reserve currencies in 2015. The current goal appears to be to establish a regional benchmark. However, as time passes, China may start to push producers to adopt the benchmark for pricing their physical crude spot cargoes and contracts.

Some economists, traders, and analysts predict that this will begin to undermine the petrodollar’s status. By adopting this futures contract, they argue, China can reduce the control over pricing held by the main international benchmarks. Shifting just part of the global oil trade to yuan, they argue, would improve the liquidity of the yuan in the global market and promote its use in global trade (one of the country’s key long-term goals). In the last year, Chinese capital controls have caused the use of the yuan in global trade to fall from 2.5 per cent of global payments to just 1.7 per cent.

Further, they argue that expanding futures trading to include other commodities would require central banks and government treasuries around the world to reduce their dollar holdings and build their store of

Chinese yuan. At present, the yuan only represents around 1 per cent of the global reserve currency, while the dollar accounts for 63 per cent, according to International Monetary Fund estimates.

Finally, it would also reduce China’s dollar holdings, and the corresponding need to ‘round trip’ them back into the US in the form of treasury purchases. These three points, they argue, could create the conditions for the yuan to challenge the dollar, by increasing the role of the yuan as a global trading currency and reducing the dollar’s importance.

Now the question is whether this contract itself is capable of achieving all these objectives.

Conditions for the contract to succeed

A futures contract is designed to allow participants to fix their prices for delivery at a later date. Consumers use them to protect against higher prices down the line, while speculators use them to bet on price movements.

To be successful, a new futures contract must (1) include a hedging requirement, (2) be attractive to speculators, and (3) be supported by public policy. Does the new futures contract fulfil these criteria?

Regarding the first requirement, China is now the world’s largest crude importer, so hedging price risks, particularly among the ‘teapot’ refiners, is a definite requirement. While Brent and WTI are light sweet crude oils, China’s refiners typically buy medium or heavy sour crudes. These heavier crude oils are not always affected by the price movements of light sweet crude, leaving China vulnerable to any changes in the light sweet market, such as the availability of BFOET (Brent-Forties-Oseberg-Ekofisk-Troll) cargoes in the North Sea market. The new futures contract, on the other hand, is



based on a basket of medium crude oils from the Middle East and China, alleviating the risk created by light sweet crude grades.

The new contract is also denominated in yuan, thus allowing refiners to effectively hedge their currency risk by passing the risk back up the chain to the producers/traders.

Regarding the second requirement, speculators play a far greater role in China than anywhere else, helping to boost trading volumes. China has a large number of speculators, day traders, and brokerage houses that are familiar with commodity markets. China has already launched a number of successful commodity contracts, including for nickel and steel, which have significant liquidity.

Regarding the third requirement, in a first for Chinese commodities, the futures contract is open to foreign participation, which is seen as critical for its long-term success. To attract more foreign participation, China will waive income taxes for overseas individuals and institutions. However, overseas oil producers and traders will have to deal with China's capital controls and occasional market interventions. These interventions have been the major reason that many other Chinese financial instruments have attracted few foreign investors.

Due to the quantity of speculators in the Chinese markets, prices are susceptible to high levels of volatility. The Chinese government has, therefore, periodically intervened to stop steep rises and falls through tighter trading rules, higher fees, and shorter trading hours. Therefore, the biggest source of uncertainty surrounding the success of this contract will be the government's acceptance of price volatility and its willingness to refrain from intervening in trading. In this case, the futures contract stipulates

that the maximum price movement within a day is ± 4 per cent. This suggests the Chinese government is not fully comfortable with price volatility, and the question remains: what will happen to the yuan contract if Brent/WTI move more than 4 per cent on any given day? It should be noted, however, that China's regulatory interventions have not prevented the successful development of contracts for other commodities.

The new Chinese future contract thus appears to fulfil the requirements for success, as long as the risk of government intervention is low. However, it still needs to attract foreign investors in order to achieve credibility. Will it be able to do so?

Physical delivery and allocation of risks

The contract is primarily designed for settlement via physical delivery. But under the contract details, all the benefits seem to accrue to Chinese refiners. The contract allows Chinese refiners to buy crude at a fixed price (eliminating pricing risk), in yuan (eliminating currency exchange risk), and to purchase the exact volume they require (reducing cash flow risk) of high-quality crude oil (reducing margin risk). For small refiners, this is a huge benefit. The quantity bought on the exchange also appears not to be counted against a refiner's crude import quota. The only real downside for refiners is that they don't know which of the seven grades of crude oil they will receive.

For sellers/producers, the contract entails significant risk. It requires that physical delivery of the crude must take place five days after the expiry of the contract. Expiry is the last day of the month prior to the trading month – for example, 31 August (if a working day) is the expiry date for a September contract. The crude oil must then be delivered between 1 and 5 September

to an Exchange-designated tank at a specific port. As six of the deliverable grades are produced in the Middle East, sellers will have to buy cargoes well (potentially up to four months) in advance of the delivery and before the expiry of the contract.

This means that effectively, given the delays that are usually seen at Chinese ports, the physical crude must arrive at the delivery port well before the delivery period, which will incur additional storage costs for the supplier. Producers/traders will also require tank space in China to be able to trade physical crude properly, as the Exchange is providing limited storage and plans to charge twice the market rate for it. Storage in China is subject to other regulations (Strategic Petroleum Reserve requirements) that may also make it less than ideal for producers/traders.

The contract being delivered means all the freight/transport costs and risks (including discharge losses and import duties) are shifted to sellers. This is amplified by the Exchange setting the price of each grade (currently at an unspecified point before expiry). This could result in the seller supplying the most expensive cargo to the buyer, instead of the cheapest like in other benchmark contracts. The only way for a seller to deal with this risk is to have the crude already in tanks in China and, once prices have been released, to deliver the cheapest to the Exchange's tank.

The minimum load-in amount (for the seller) of crude oil to the Exchange's delivery tank is 200,000 barrels; the minimum load-out amount (for the buyer) is the same. In other words, a seller, having purchased between 600,000 and 2 million barrels of crude, may only be required to deliver 200,000 barrels. This leaves the seller with 0.4 to 1.8 million barrels to find a home for and the price risk that entails.



Therefore, the details of the contract suggest it is currently designed only for the local Chinese market and not for international companies. Current contract terms effectively prevent anyone but state-owned oil companies and large teapot refiners from entering as sellers.

Financial speculation

Financial speculation is possible up to the market close on the eighth trading day prior to the last trading day of the crude oil futures contract – for example, 23 June for a July contract. One way the Chinese authorities have tried to control who can trade the contract is by adding a minimum 5 per cent trading margin. This should keep a lot of speculative traders out. As of this writing, anybody deemed a ‘natural person’ (a client that may not deliver or receive crude oil) must hold zero lots. If that person has not cleared the position on the seventh day, the position will be directly liquidated by the Exchange.

Now the big question is whether there will be price spikes on or around the eighth day before expiry as these ‘natural persons’ try to clear their positions. At settlement on the eighth day, some may still be holding positions that they cannot close because the participant on the other side of the trade wishes to receive or deliver physical crude. What price will they pay when their positions are being liquidated? What happens to the contract of the company wishing to receive or deliver physical crude?

Conclusion

This contract will likely need to undergo a number of cycles before traders can fully understand how it works. Traders will probably hold positions for a short period of time before liquidating their positions. Open interest will therefore be a key metric to assess the success of the contract.

However, this contract has many of the

ingredients needed to be successful and therefore has a chance of becoming a regional benchmark, although this will not happen overnight. In its current form, sellers assume almost all of the risk. For the contract to become a true regional benchmark, the risk will need to be more evenly spread between buyer and seller.

The current design of the contract makes it likely that physical trading will occur mainly between Chinese state-owned oil companies and local teapot refineries. For the contract to be taken seriously as a regional benchmark, that will need to change. To achieve that goal, it will need to adapt, as WTI and Brent have done before it.

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URALS CRUDE OIL AS A FUTURES CONTRACT BENCHMARK

Alexei Rybnikov

On 29 November 2016, the Saint Petersburg International Mercantile Exchange (SPIMEX) started trading physically settled SPIMEX Urals crude futures (FOB Primorsk). Sufficiently large and freely tradeable volumes of Urals oil from the ports of the Baltic Sea would ensure that market forces prevail and that Urals oil is appropriately priced. We predict that with an open, transparent, and well-regulated futures market, the acceptance of Urals FOB Primorsk as a superior benchmark for many of the world’s main export crude oil streams will follow.

The superiority of FOB Primorsk

Baltic oil is the most appropriate price and value basis for the two other main export streams for Russian crude oil, Kozmino and the Black Sea, because oil is regularly shipped from the Baltic into the Far East and the Mediterranean, the natural destinations for East Siberia–Pacific Ocean (ESPO)

ex-Kozmino and Urals ex-Black Sea, respectively.

The flexibility of the physical flows of Russian oil ex-Baltic to other regions will enable Russian producers to best manage their oil flows by destination and thereby optimize the performance and profitability of their operations. Urals ex-Mediterranean and ESPO ex-Kozmino do not enjoy the same flexibility of destination, on a regular basis, as ex-Baltic oil. Rather, they are priced relative to Urals ex-Baltic and thus form a single, robust benchmark for Russian crude oil export operations.

To achieve the transparency and price discovery that mark the operation of a successful futures contract, it is preferable that any Baltic Urals contract be deliverable. Baltic deliveries operate with few logistics or quality problems.

Key elements for an FOB Primorsk Urals futures contract

Urals ex-Baltic’s fungibility in terms of logistics and quality makes it well suited to form the basis of a deliverable futures contract. It is, however, vitally important that Russian oil producers’ contracts for physical delivery be standardized in line with futures-related pricing and delivery mechanisms. To the advantage of the futures contract, Russia imposes no restrictions on the secondary trading of Russian oil.

The volume of ex-Baltic deliveries of Urals crude oil is twice that of the Brent-Forties-Oseberg-Ekofisk (BFOE) complex, which reputedly is the price basis for more than 60 per cent of the world’s crude oil exports by volume. In addition, Brent futures and the Dated Brent quotation form the price basis for a huge volume of related exchange-traded and over-the-counter contracts.

The scale and scope of the supply and consumption of Urals oil is perhaps greater than that of any other single crude oil stream in the North Western Europe (NWE) region. Multiple



suppliers and consumers will be able to participate in the transparent price discovery that exchange-traded futures will bring as well as in exchange trading in order to efficiently and effectively manage their operations.

The primary producers and end consumers of Urals oil, under the current pricing regime, suffer multiple layers of risk, on top of the natural volatility of oil markets. The real function of a futures exchange is to provide a forum where buyers and sellers of risk may transact; but in order for such risk to be palatable in contract form, it must be clear and distinct and not confused in the stratification of risks that Dated Brent-related pricing entails. Reducing the risk of Urals oil to market price risk benefits the producers and consumers of Urals crude oil. Reduction of this single risk element will allow efficient hedging via the ex-Baltic futures contract.

Arbitrage

Certain producers of Russian crude oil are sellers of complementary crude oils in NWE, the Mediterranean, and ex-

Kozmino. These special circumstances would greatly enhance these producers’ opportunities to manage their operations and their risks with a single benchmark as the price basis for all three export regions. To relate the prices to a single benchmark makes it immediately apparent when arbitrage opportunities open and naturally closes them without the intervention of intermediaries.

To complete the price integration of all main Russian crude oil export routes, an FOB Primorsk futures contract can form the basis for Druzhba and associated pipeline deliveries. Since Kozmino seaborne already constitutes the price basis for ESPO pipeline deliveries, this would result in FOB Primorsk serving as the price benchmark for Russian oil in NWE, the Mediterranean, the Druzhba pipeline, Kozmino, and the ESPO pipeline. This integrated approach to the pricing of Russian export oil would establish a system of valuation that would be difficult to resist and would promote its use as a benchmark for other non-

Russian crude oil streams.

SPIMEX Urals crude deliverable futures contract

On 29 November 2016, SPIMEX started trading in physically settled SPIMEX Urals crude futures (FOB Primorsk). Access to the SPIMEX futures contract trades is granted to Russian and foreign legal entities. The SPIMEX Urals crude futures contract is settled by physical delivery upon expiration. Such a futures contract has a direct link with the crude oil spot market and prevents price manipulation.

Terms and conditions of the physical delivery are set out by SPIMEX along with key Russian oil producers in line with current market practice. Crude oil under the futures contract is delivered FOB Primorsk by standard deliveries, each equal to 720,000 barrels (about 100,000 metric tonnes, a full cargo – see the table below). In 2017 over 4,000 Urals crude futures contracts (FOB Primorsk) were traded.

Contract Terms	
Settlement method	Deliverable
Underlying asset	Russian export Urals-grade crude oil
Hub name	Primorsk
Currency	US dollars
Contract size	1,000 barrel
Standard delivery	720,000 barrel
Minimum price flux per barrel	US\$ 0.01
Last trading day	21 days prior to the first calendar day of the delivery month
Delivery period	Delivery month
Delivery price	Final settlement price of the futures contract set on the last trading day
Performance procedure	The parties enter into physical contracts at the SPIMEX derivatives market on the terms and conditions and under the procedures set forth in the relevant contract specifications, the Trading Rules, and the in-house regulations of the clearinghouse.



In 2017 SPIMEX successfully attracted new participants to trading in the Urals futures. Market makers, setting buy and sell quotations, will provide initial liquidity along with Russian oil companies.

Physical deliveries of crude oil should be the next step in the promotion of the project. SPIMEX is now actively working on this issue and has solved several issues related to the customs clearance of the export contracts required to carry out the futures contract. Russian Federation currency control regulations have been amended to allow, and provide the appropriate conditions for, the use of foreign currency as collateral by non-Russian residents. The remaining regulatory item on the agenda is the clarification of the withholding tax regime for foreign companies' income from operations in the Russian derivatives market.

Step by step, SPIMEX is working to solve many complex issues, developing the contract in close interaction with authorities and Russian and foreign participants in the crude oil market. We believe that a Urals crude oil FOB Primorsk exchange-traded futures contract is an appropriate and rational choice for a much-needed improvement in the system of global energy pricing.

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