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This latest issue of the *Oxford Energy Forum* provides an update on the state of play of the world's oil benchmarks. The theme of oil benchmarks was examined in the February 2012 edition of *OEF*. The new edition is timely. In May 2013, the world of oil trading was thrown into turmoil by raids on the offices of Shell, BP, Statoil, and Platts (the price reporting agency), conducted by the European Union alleging collusion to manipulate prices. September 2013 saw the publication of a draft proposal by the European Commission for the regulation of financial benchmarks in the wake of the LIBOR scandal. The proposal, which also applies to commodities such as oil, has been described as 'draconian' and 'unworkable' by industry analysts.

The first section of this *OEF* provides analysis of the need, or otherwise, for such a tightening of the regulations on benchmarks, and evaluates the consequences for both the market and price discovery.

Opening the *Forum*, *Peter Stewart* writes that the decades of improvement in oil market transparency, achieved over the years by price reporting firms and exchanges, may be about to be reversed by the recent benchmark regulations proposed by the European Commission. Stewart notes that these rules are being rushed through before the results of an EU probe into oil pricing, that began with highly publicized raids on the offices of Shell, BP, Statoil, and Platts, have been made public. Stewart reviews the evolution of oil market transparency from the 1970s to the present, and concludes that oil markets in Europe have become less transparent in recent years, partly as a result of misplaced regulatory zeal. In contrast, oil markets in Asia have prospered, and have grown in transparency and liquidity in this period.

Liz Bossley says that the lack of any dénouement from the EU probe of oil prices does not mean that all is well in the world of oil price reporting. Bossley says that while oil companies have the motive, means, and opportunity to influence prices, she suggests that any distortion in prices is likely to be to be driven by a desire to push prices lower – in contrast to EU allegations that companies colluded to generate high prices. Bossley says that the Platts window – the period at the end of the day when companies' bids, offers, and trades are recorded for use in the daily assessments – may be

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vulnerable to non-arm's length transactions being done at 'off-market' prices, as Platts has no power to force any company to reveal all the deals it does.

Peter Caddy sees the European Commission's proposal for the regulation of benchmarks as flawed. Caddy says that the proposal has been drawn up on the assumption that the oil market, and all other commodity markets, are inherently like financial markets. The reality is that oil is a physical commodity with complex quality specifications, logistical constraints, and uneven liquidity. Unlike activities in the financial markets, oil contracts are highly non-standardized. Caddy says that these factors would make a European regulation that is designed for financial market benchmarks, such as the discredited LIBOR interest rate, inappropriate in physical energy markets. He notes that the Commission's proposed regulation goes far beyond the recommendations of the International Organization of Securities Commissions (IOSCO), which were endorsed by the G20 in November 2012.

Patrick Heren believes that the bias of regulators is towards tidy methodologies based on 'verifiable' data. He argues that this bias is leading potentially to the introduction of tightly prescriptive rules that would seriously distort physical commodity trading in Europe. Heren notes the EC's benchmarks proposal would set rules on who could contribute information to Price Reporting Agencies (PRAs) and on the extent of their participation in trades making up an index, as well as putting potentially unlimited financial liability on those contributing information. He argues that the proposed benchmarks regulation is likely to make energy markets more opaque rather than more transparent, and therefore more liable to manipulation.

David Fyfe and *Brian Lewis* describe the business model for commodity traders and how the trading business has been evolving over the years. Contrary to the general belief, commodity traders have been subject to an increasing array of regulations – which is not unexpected given their wide geographical reach and their involvement throughout the global energy value chain. However, the authors argue that authorities should be careful when introducing new regulations; otherwise these could result in some unintended consequences, with the ultimate effect of increasing the cost of energy to the final consumer. The authors also warn against the risk associated with treating commodity traders like financial institutions, as the two business models are fundamentally different; and hence they call for physical participants to cooperate closely with regulators to avoid the risk of inappropriate or excessive regulation.

The *Forum's* second section focuses on the evolution of oil benchmarks around the world, given the changing landscape of supply and demand for the different grades of oil.

Robert Levin opens the section on benchmarks by looking at the role of US pricing benchmarks, comparing these with Brent. He argues that US benchmarks are underpinned by market mechanisms based on straightforward designs; information about market fundamentals; and lack of artificial of barriers to entry, which leads to an active arbitrage process. This in turn ensures that US benchmarks, including WTI, reflect accurately supply and demand fundamentals. The author argues that this is in contrast to the Brent structure, where regular information about oil market fundamentals is missing. At a deeper level, Levin questions whether existing mechanisms in the Brent system allow a role for arbitrage, arguing that there is 'nothing that compels physical market supply and demand discipline to be administered through these mechanisms'. Levin concludes by arguing that unlike the US market benchmarks which reflect fundamental supply and demand (and are subject to confirmation by authoritative data), there is still a 'need to determine what are the prime driving forces in the North Sea market and whether fundamentals are at the core or something else altogether'.

Amrita Sen examines recent developments in the Brent system and argues that while the Brent benchmark is still responsive to global supply and demand fundamentals, it also responds to Brent-specific issues. Sen argues that there are three main factors setting the stage for a considerable increase in the volatility in Brent time spreads: the South Korean arbitrage; the introduction of the Platts escalator for assessing Dated Brent prices; and the greater sensitivity of Brent to European refining margins. The author discusses each of these factors in detail and argues that among these, refining margins will have the biggest impact and are likely to be a constant factor impacting sentiment about the structure of the Brent curve, especially given the current glut in global refining capacity.

Owain Johnson examines the prospects of new benchmarks emerging in the Mideast region. Johnson describes the recent dynamics in the region, such as the increase in refining capacity and the increase in domestic demand, which are leading to the development of new trading practices. According to the author, these changing regional dynamics and shifts towards increased regulation will have their biggest impact on the Dubai crude oil assessment, which suffers from low levels of trading activity and only a small number of participants. This will create opportunities for new benchmarks to emerge in the 'post-Dubai world', including consolidation of the position of DME futures contracts. Johnson argues that while many benchmarks could emerge, the success of any benchmark will be determined by tight regulation and a tight convergence with the underlying physical market.

Jim Henderson explores whether East Siberia/Pacific Ocean (ESPO) crude could become a new benchmark in the Asian region. Henderson argues that while it is clear that ESPO crude has changed the dynamics of the Asian crude market, it remains less clear whether ESPO can meet the conditions for becoming a benchmark crude. The article analyses some of these conditions and concludes that it is still some way from the emergence of ESPO as benchmark. The author identifies some of the key challenges, which include the establishment of 'a solid production base in East Siberia, a continued diversity of buyers and sellers, a secure quality assessment and, most critically, an improved perception of Russian political risk'.

Finally, *Jorge Montepeque* looks at the gyrations of oil and commodity prices in 2008 and after, and concludes that the core role of the market – that of balancing supply and demand through price – has worked well in this period. Montepeque traces the rise in the price of Dated Brent crude oil to above $145/barrel in June 2008, and its subsequent fall to $35/barrel later in the year. He argues that other commodities – such as coal, iron ore, and food, among others – experienced similarly sharp rises and subsequent reversals. Even if price volatility is painful, Montepeque argues that the market should be allowed to function without intervention.

Contributors to this issue

LIZ BOSSLEY is CEO of the Consilience Energy Advisory Group Ltd and author of *Trading Crude Oil: the Consilience Guide*, published in May 2013.

DR PETER CADDY is Business Development Director, Argus Media.

DAVID FYFE is Head of Market Research and Analysis, Gunvor Group.

PATRICK HEREN is the founder of Heren Energy.

JAMES HENDERSON is Senior Research Fellow at the Oxford Institute for Energy Studies.

MICHAEL HOCHBERG is an independent analyst.

OWAIN JOHNSON is Chief of Products and Services, Dubai Mercantile Exchange.

ROBERT LEVIN is Managing Director, Energy Research and Product Development, CME Group.

BRIAN LEWIS is Compliance Director, Gunvor Group.

JORGE MONTEPEQUE is Global Director, Market Reporting, Platts.

AMRITA SEN is Chief Oil Analyst, Energy Aspects.

PETER STEWART is Chief Energy Analyst at Interfax Global Gas Analytics.

Hard Truths about Market Transparency

PETER STEWART

In the wake of the LIBOR scandal, legislators have rushed through new rules intended to put a stop to market manipulation, purporting to improve market transparency.

The European Commission issued its latest proposal – for a regulation 'on indices used as benchmarks in financial instruments and financial contracts' – on 18 September 2013 (SWD(2013) 336/337).

The proposed regulation follows a report by the International Organization of Securities Commissions (IOSCO) issued in November 2012, which made recommendations about the oversight of activities by so-called Price Reporting Agencies (PRAs). However, the EU regulation goes far beyond the recommendations of the IOSCO report, despite claiming to be aligned with them.

> ***'The EU proposal suffers from a not uncommon delusion among regulators: "transparency" can be mandated from above.'***

The proposed regulation opens a Pandora's box of issues which include: the viability of implementation of the new rules; issues of extra-territoriality; press freedom and the right to express opinions; the possibility of reduced competition in energy pricing; and the potential for political interference in price-setting. While all of these issues are of concern, this article addresses only one of the many issues raised by the regulation: that of the transparency of the market.

The EU proposal suffers from a not uncommon delusion among regulators: 'transparency' can be mandated from above, by enforcing the disclosure of masses of documents and data, and putting in place an oversight procedure, with the threat of heavy penalties if the rules are not followed. This is not the case. Market transparency evolves, much as it does in any other walk of life, over time, and through open and intelligent dialogue. This dialogue may be among professionals involved in the market – from industry, academia, and the press – all of whom have competing interests and goals. If the dialogue at times gets fractious, that is probably good rather than bad.

This article contends that oil markets in Europe have become less transparent in recent years as a result of regulatory meddling; that the oil market in Europe is now less transparent than similar markets in Asia which have traditionally been regarded as more opaque; and that price reporters, a main target of regulators' zealous efforts, are likely to function less well as a result of the new rules being rushed through.

The EU does not define what it means by transparency in its recent legislative proposal, but it seems to have in mind a set of clear bureaucratic procedures that result in a mass of auditable data. The definition used here is much simpler, and is that provided in *Webster's* dictionary: 'transparent: characterized by visibility or accessibility of information especially concerning business practices'. Such a definition implies more than just the existence of masses of data. It implies that if you want to understand market activity, rather than just observe the stream of data it generates, you can do so with reasonable ease.

So there is a vertical as well as a horizontal dimension to transparency. The latter requires the disclosure of trade data, such as happens in the Platts window and on futures exchanges. The former is more subtle, requiring a dialogue about why the market is moving and what the consequences are – such a dialogue may include market participants and market observers. This explanatory role has been provided in the past by price reporters associated with price reporting firms and news agencies.

The evolution of these aspects of transparency is considered in the following section.

Evolution of Market Transparency

The evolution of oil market transparency has been a slow and often painful process. Price reporting firms and news agencies have played a key role in pushing it forward, their efforts often being resisted by market participants who by and large prefer anonymity.

1973–1985

During the period 1973–1985, oil markets lacked transparency, even in Europe. Oil traders at that time had a justifiably shadowy reputation. Many of the deals they did were private and confidential, and news about them leaked out to the market through a privileged network of well-connected oil traders. When writing his bestselling book about the major oil companies, *The Seven Sisters*, published in 1975, Antony Sampson had faced a wall of secrecy about their commercial activities.

This was an opaque market. The job of a price reporter in those days was to relate as much as they could risk reporting about the trades that were taking place. The 'data gathering process' involved intensive phone calls through the afternoon, but this was supplemented by long and often liquid lunches, meetings in IP Week and similar industry events, and even, on occasion, conversations while smoking on street corners in Mayfair where many of the traders had their offices. The names of the counterparties to physical oil transactions were known by those in the market, but were never published.

1986–1997

The period between 1986 and 1997 saw increasing transparency, as the move to formula-based pricing of crude oil boosted spot market activity. From 1985 onwards, electronic screens operated by price reporting firms such as Platts and Argus and news agencies such as Reuters and Dow Jones played a growing role in price discovery in the physical oil market.

The process of price discovery in this period was imperfect but reasonably efficient. In the 15-day Brent market as it then was, it was not uncommon to have around 50 full-size cargo deals (30 million bbl) reported over the course of a day. Many of the deals were 'leaked' to reporters within minutes of their being concluded. A high degree of liquidity existed in other forward markets such as open spec naphtha, non-EEC gasoil, and fuel oil cargoes for delivery to the CEGB.

'As markets became more liquid and more volatile, however, assessment methodologies in Europe lagged behind.'

Physical markets which were not speculatively traded were often much less liquid. There was a significant difference between trade in northern Europe (particularly the reasonably liquid ARA hub), and trade in the Mediterranean region where very little fixed price business happened.

The price discovery process – which was pioneered by price reporters such as Platts, Argus, ICIS, and others, often to the intense irritation of oil companies – was boosted greatly by real-time price reporting by the news agencies such as Reuters and Dow Jones. A further leap forward came with the advent of oil futures in Europe, notably the IPE gasoil contract (1981) and IPE Brent contract (1988) which made the outright price highly visible. By the end of the 1980s, also, the so-called Wall Street refiners had entered the physical market and were making markets in Over the Counter (OTC) swaps and options, so the size of the derivatives market burgeoned and prices gradually became more visible.

By 1993, when Paul Horsnell and Robert Mabro published *Oil Markets and Prices*, the oil market's transparency had developed enormously:

'Before the mid 1960s, the major oil companies were their own price assessors, calling out prices unilaterally, a role taken up by OPEC through to the end of the 1970s. The growth of spot markets for crude oil created a need for price assessment, at first simply as a contribution to transparency. … However, the assessed prices … began to be used in trade rather than merely as an aid to trade.'

This period is characterized by a growing level of physical market transparency. For instance, reporters who monitored the Transworld squeeze of the Brent market at the end of 1987 published the key deals on electronic screens, and the oil market story rapidly became front-page news. The names of those companies involved in the squeeze were published, whereas 'naming names' had hitherto been off limits.

Asia at that time, in contrast to Europe, had among the least liquid and least transparent markets. Deals were almost invariably done on a Platts-related basis, but there was no obligation to disclose them to Platts. The pool of fixed price transactions was limited, and with the bulk of deals done on a Private and Confidential basis, subjective judgement was often used when verifiable information was unavailable.

The emergence of the Platts window in Singapore in the early 1990s provided a solution to this. The advent of the window coincided with a push by investment banks to sell derivatives, such as swaps, to oil market participants in Asia where demand was burgeoning. By forcing traders to objectify their opinions, and by using the increasingly visible swaps prices in the assessments, Platts brought transparency to what had been a failing assessment process.

1997–2001

In the period 1997–2001, futures markets gradually became the locus of outright price discovery in real time, and price reporters used their electronic screens to communicate physical oil market information, if not in real time, on at least an hourly basis. Swap market liquidity grew exponentially and market transparency was enhanced by growing competition among the news agencies and the price reporting agencies.

As markets became more liquid and more volatile, however, assessment methodologies in Europe lagged behind.

In the 1980s and 1990s, when markets were typically less volatile, Platts had used a 'representative' trading range over the day in most of its oil products assessments. In this system, traders reported deals through the day, and by the close reporters would compile comprehensive lists of deals done over the whole trading day. This involved subjective assessment, as the ranges published did not represent the highs or lows of the day, but were typical ranges traded with outliers removed. If a deal smelt bad, it was tossed out of the basket without remorse.

In such a system, it was often in traders' interests to widen the spread of trades over a working day. Also, as long as deals were reported retrospectively, it was impossible to track at exactly what time of day they were done transparently, and therefore whether they made sense in light of the prevailing crack spread and timing structure of the market.

With physical crude oil prices dropping to all-time lows below $10/bbl in 1986 and 1998, regulatory scrutiny of the physical market was virtually non-existent. Such investigations as did occur were performed by competition authorities looking at the link between the wholesale and retail price. All this changed in 2001, however, when the Enron scandal revealed false reporting of deals in the gas market, diminishing regulatory confidence in the price reporting firms – if indeed it had ever existed. Meanwhile, the inexorable rise in oil prices between 1998, and the all-time highs reached in 2008, catapulted the oil market to the top of regulators' priorities.

'… the reporting of physical oil transactions outside these assessment 'windows' has become less transparent than it was a decade ago.'

In response to Enron and other scandals, regulators introduced a series of regulations aimed at reducing the risk of market abuse, and upping the penalties if it were identified. Simultaneously, the main PRAs took decisive steps to make their assessment procedures more robust and transparent. These included: putting in place auditable systems such as the Platts window, to diminish the risk of subjectivity in an assessment; formal compliance regimes that ensured best practices were being followed; and more rigorous procedures for correcting, re-specifying, and phasing out assessments. Similar steps were taken by other price reporting firms such as Argus, resulting in an assessment regime that was arguably more rigorous than that for any other commodity.

2002 onwards

The period from 2002 to the present is characterized, therefore, by increased rigour in assessment procedures, mounting regulatory scrutiny, but a very uneven development of market transparency. Horizontal transparency has increased greatly. With the advent of assessment windows, deals worth tens of millions of dollars were conducted in the plain light of day, with the names of counterparties in physical transactions revealed to the market at large. However, vertical transparency of the market – the dialogue that allows an understanding of the activity of market players – has deteriorated.

No Comment

Nowadays, traders at major oil companies who are asked by price reporters about why prices are moving will probably decline to comment, and will direct further requests to a compliance officer or the Press Office. Most of the majors now will only allow approved disclosures about their trading activities – such as those made in 'the window' where bids, offers, and deals are communicated, or in their end-of-day deal summaries which cannot be further checked to evaluate the significance of the deals. The opinions of individual employees in relation to the direction of prices are not allowed, as this may be construed as 'signalling' by the company, although a senior trader may sometimes be assigned the job of managing the dialogue between trading desk and the media.

This lack of dialogue limits the 'visibility and accessibility of information'. Reporters are resourceful people, however, and it is likely that valuable information is exchanged anyway – whether on mobile phones or in face-to-face meetings – and of course the diligent reporter will disseminate this to the market at large. However, the open dialogue between market participants and reporters that used to be habitual has been curbed by regulators' concern to stop selective disclosures.

The end result is that, while a segment of the physical market is made highly transparent by the Platts window and equivalent systems offered by other vendors, this transparency is confined to a small portion of the trading day and to the relatively small number of grades of oil that are reasonably liquid. That is not to say, of course, that the window is anything but a boon to market transparency; indeed, the 'naming of names' in real time provides a degree of transparency that is unavailable for other commodities.

But the reporting of physical oil transactions outside these assessment 'windows' has become less transparent than it was a decade ago. Companies faced with severe penalties for misreporting deals, and with no penalties for non-reporting of deals, have taken the easy course. The number of deals reported outside the assessment windows has declined. The ready flow of information between traders about their deals, the circumstances of the deals, the peculiarities of the oils traded, all that rich vein of information that price reporters gathered throughout the 1980s and 1990s to understand and contextualize the deals, has become less available.

There is a profound irony here. While the horizontal transparency of the market has been improved by the efforts of price reporters, regulators remain antipathetic to their efforts; meanwhile, diminution in the market's vertical transparency is the unintended consequence of regulators' efforts.

Regulators who were rattled by the LIBOR scandal and who are now trying to rush through a generic fix for 'benchmarks' in markets (including commodities) seem not at all bothered by this reality. They should be. Commodities are not standardized financial instruments, but are highly differentiated in terms of quality, logistics, and fungibility with other grades. Vertical transparency is necessary. It is not just a question of averaging masses of data, but of understanding what the data means.

The EU benchmark proposal is likely to harm the transparency of the market rather than improve it. The threat of massive fines for 'misassessment' can only deter rather than encourage competition among the price reporting firms.

Meanwhile, there is a risk that regulatory scrutiny will reduce market liquidity, or displace it to regions outside Europe with laxer regulatory and compliance regimes. Trading activity in Singapore has burgeoned in the last decade, and market activity in the trading windows and outside has become more liquid and more visible.

'Nothing in the EU's proposed benchmarks regulation will allow the increasingly opaque European oil market to function better.'

This is unsurprising. When the risks of getting involved in discussing market activity outweigh the rewards, market participants are likely to retreat into their shells. When the risks of engaging in market activity outweigh the potential rewards, those involved are likely to vote with their feet and move to other markets. Price reporters already comment anecdotally that financial institutions are providing less deal data in Europe. Industry sources have described the new EU regulation on benchmarks as 'draconian' and 'unworkable'.

Conclusions

No-one would disagree with the regulators' goals of stopping manipulation, averting collusion, and improving transparency in the oil market.

The EU benchmark proposal will not achieve these goals, however. The urgency of the new legislation appears to be predicated on a loss of public confidence in the functioning of the markets, and the assumption that widespread manipulation of the energy markets has actually occurred. After the EU raids on oil companies and Platts in May 2013, a senior EU official was quoted in the press as saying: 'We are witnessing more alleged and potential manipulation of benchmarks in energy markets'.

This statement is breath-taking because it is the EU itself that has generated these allegations of manipulation. Meanwhile, the new regulations are being pushed through even before it has been established whether Shell, BP, Statoil, or Platts have a case to answer.

In this overcharged atmosphere, the cause of market transparency is suffering. Nothing in the EU's proposed benchmarks regulation will allow the increasingly opaque European oil market to function better.

The hard truth is that regulators, in trying to make things better, have made them much worse. The proposed legislation on benchmarks indicates another wrong turn that is about to be taken by the EU juggernaut. ■

Motive, Means, and Opportunity

LIZ BOSSLEY

When the European Commission (EC) swooped, like the SAS, into the offices of Shell, BP, Statoil, and Platts (the price reporting agency), on 14 May this year looking for evidence of manipulation of Platts prices, it seemed as if a major overhaul of the oil market, not just of oil price reporting, might be in the offing.

This EC raid triggered a separate oil price investigation by the US Federal Trade Commission (FTC) at the end of June and, perhaps scariest and least predictable of all, a class action suit brought by a Chicago trader in the District Court of the Southern District of New York against a range of oil companies and un-named co-conspirators for reporting inaccurate information to Platts.

> ***'It worth reminding ourselves of who is motivated by high oil prices and who is motivated by low oil prices.'***

Now, six months later, the market has got tired of waiting for the dénouement and it is business as usual in oil trading.

No News is No News!

But this does not mean that all is well in the world of oil pricing, even if the EC and FTC investigations eventually decide not to publish their conclusions. It may just mean that the data that has been submitted to those regulatory authorities that police the market (or that they themselves have seized in the hope finding a smoking gun) is so complex that they are not yet ready to share their findings. Or it may be that those findings are showing 'the wrong result'.

The *Independent* newspaper reported on 15 May, the day after the EC raid, that 'Oil executives could face jail if they conspired to keep petrol prices high by rigging the market, David Cameron has warned'. This suggests that the public perception of the 'crime' under investigation is one of artificially inflated prices and that the 'victim' is the man in the street.

But what if the EC investigation shows evidence that oil executives conspired to keep prices low? Does that mean they should get a pat on the back from the UK's Prime Minister?

It is worth reminding ourselves of who is motivated by high oil prices and who is motivated by low oil prices before throwing around accusations about which companies, if any, are up to no good in their reporting of price information to the oil Price Reporting Agencies (PRAs).

Motive

Upstream producing oil companies like high crude oil prices for obvious reasons, but they do not necessarily like to see those high oil prices recorded and publicized by the PRAs. The higher the crude price that gets reported, the higher the price used by state-owned National Oil Companies (NOCs) in Production Sharing Contracts (PSCs) to calculate the number of barrels that the contractors are allowed to take in order to recover their exploration and development costs and to earn a profit before the state qualifies to take a share. The level of crude oil prices also determines the size of the royalty and other production tax bills that contractors must pay. In those regimes that use Service Contracts, rather than PSCs, the higher the reported crude price the more the oil industry must pay to buy barrels from NOCs.

This is not news: it was the tendency of the oil industry to understate oil prices that prompted the formation of OPEC back in 1960.

The high upstream rate of tax – sometimes in excess of 80 per cent – means that the integrated oil companies (those owning both refineries and distribution outlets) would prefer to see their profits being earned in the downstream sector where the rates of taxation are much lower – sometimes lower than 30 per cent. The dream ticket for the integrated oil company is low crude oil prices and high refined product prices.

But surely non-integrated exploration and production (E&P) companies can be relied on to push for higher oil prices. After all no-one wants to minimize their tax bill by earning less income (in other words, selling at low prices). Not necessarily. If E&P companies can disguise the high oil prices they receive and only let the regulatory and taxation authorities see lower prices, then they can enjoy tax-free income. The easiest means of achieving this is by using non-arm's length transactions.

Means

In the oil sector the term 'arm's length' refers to trade between companies that are not affiliated in any way carrying out deals that do not involve barter or swap arrangements. In an arm's length deal there is no 'consideration', other than price. It is a routine feature of the industry that a large number of deals that get reported to NOCs and other authorities are non-arm's length. For example, oil producers regularly supply their own crude oil production to their affiliated refining system. When such deals are reported as 'non-arm's length' the NOCs and tax authorities use the prices assessed by PRAs to calculate cost recovery, profit share, royalty, and other taxes, rather than the price reported by the producing company.

It is possible, but unlikely, that oil companies would mis-report non-arm's length deals as arm's length deals to regulatory or tax authorities. That would probably constitute fraud. But PRAs are not regulatory or tax authorities. The suspicion that prompted the EC investigation is that the prices that get shown to the PRAs are not subject to the same degree of rigour as those reported to the statutory authorities.

If a company wanted to use the non-arm's length technique to depress reported prices, this would involve the company in selling one cargo of crude oil to a third party and buying back a different cargo from the same third party, with both the purchase and the sales prices being below the true market level. That way neither company loses out. If only one of the two deals is shown to the PRA, this would mislead the PRA into believing that prices are lower than they are in reality. The reported prices of refined products could also be artificially inflated using the same technique.

This places a heavy burden of responsibility on PRAs to spot when they are being misled, while having no authority to audit or sanction those companies that they suspect may be misinforming them. In what was probably an attempt to protect itself from manipulation, the PRA on which most EC and FTC attention is being focused, Platts, introduced its 'window' system. In doing so it may have inadvertently opened up a window of opportunity to any oil company wishing to push reported prices down or up and may have actually facilitated what it sought to avoid.

Opportunity

The Platts window provides a snapshot of a wide range of benchmark prices at certain key points during the day in a variety of regional markets – such as 4.30 pm in London and in Singapore, and 3.15 Eastern Standard Time. To ensure that it is shown consistent and comparable data, Platts publishes guidelines and methodologies explaining what form companies' contracts must take in order to be included in its price database. Furthermore, Platts will not accept data from just anyone. If, in its sole opinion, a company does not deal on equal terms with other players in the market, it can and does exclude deals done by that company from its database.

For example, for a period of time during the banking crisis, Platts excluded data provided by American banks such as Morgan Stanley and Goldman Sachs. Similarly, if a company indicates in the Platts window that it will deal at a particular price level, but does not honour that commitment if a third party tries to accept its price indication and execute a deal with it, then Platts will 'box' the defaulting company for a period of time, which may be days or weeks. In other words, Platts sanctions companies by locking them out of the window process.

The actual window price discovery process is straightforward. Companies wanting to ensure that their voice is heard in the determination of the price that is eventually published (and who are acceptable to Platts) need only phone, fax, email, or otherwise e-messenger Platts with bids and offers during the half-hour window. Alternatively, companies can engage directly with other players in the window online using the Platts software that is hosted by the Intercontinental Exchange (ICE). The half hour progresses with bids and offers changing within limits, or increments, dictated by Platts.

For the key benchmark grades of oil and refined products the only deals *or price indications* that matter are those transacted in the last few minutes of the half-hour window. It is often the case that no deals are transacted and that the price assessment that is published is based on the best bids and offers at the Market on Close (MOC). The market does not actually close – MOC is the term used by Platts to refer to the end of its half-hour window. Trades in non-benchmark grades throughout the day are considered assessing the price differentials that are applied to the snapshot of MOC benchmarks.

In the days before the Platts window existed (before 2002) any company wishing to influence the oil price that is reported had to remain vigilant around the clock, stepping in to back a play to push the price one way or another with a significant volume of trade. After the introduction of the Platts window, any company with a similar motivation only has to engage with the process during a half-hour period and can have an impact on the price that is published – often without actually transacting any volume.

> ***'… the prices that get shown to the PRAs are not subject to the same degree of rigour as those reported to the statutory authorities.'***

Platts is at considerable pains to ensure that it is not being misled and that any company indicating its willingness to deal at a particular level must stand by that indication if a third party steps in to hit any bid that is too low or lift any offer that is too high compared with market levels. But nothing can protect Platts from any non-arm's length transaction done at 'off-market' prices which is shown to Platts as if it were arm's length. Platts has no power to force any company to reveal all the deals it does. Companies can therefore cherry pick which deals to show in the Platts window and which to exclude. There is no sanction against showing only one half of a non-arm's length transaction.

This must be what the EC and the FTC are looking for as they plough through the data they have seized on their raids on the oil companies. Only time will tell if the regulatory investigations will uncover any evidence indicating misrepresentation of prices to Platts.

So, with apologies to Cluedo, are we going to see a case of 'the oil companies in the Platts window, with the non-arm's length transaction'? The EC and the FTC are going to have to exercise their 'little grey cells' to solve that complex puzzle.

Regulation and Reporting the Price of Oil

PETER CADDY

The European Commission published a proposal for the regulation of benchmarks, including benchmarks used in oil pricing, on 18 September 2013. Unfortunately, the proposal fails to understand the nature of oil trading and threatens the industry's ability to provide affordable and reliable supply to Europe. The professional reporting of oil prices requires a deep understanding of markets, especially as the market for crude and petroleum products is vast and complex. Any attempt to regulate benchmarks in these complex markets requires a similar level of understanding. Without it, regulation jeopardizes the efficient trading of oil.

'The PRA Principles are a proportionate set of recommendations for market authorities regarding oil benchmarks used in the pricing of financial instruments.'

PRA principles

The Commission's proposed regulation contrasts sharply with the work stream established by the G20 leaders to examine and make recommendations concerning price reporting agencies (PRAs). The final result of this work stream – an in-depth examination by the International Organization of Securities Commissions (IOSCO) and international agencies with an understanding of the physical oil market, such as OPEC, the IEA, and the IEF – was the document *Principles for Oil Price Reporting Agencies Final Report* (the PRA Principles), published in October 2012. IOSCO's PRA Principles were endorsed by the G20 in November 2012. The PRA Principles are a proportionate set of recommendations for market authorities regarding oil benchmarks used in the pricing of financial instruments. IOSCO, together with the other international organizations, explicitly recommended that the principles should be applied by the PRAs to all their benchmarks used in the pricing of financial instruments, and not just to oil benchmarks.

One requirement of these principles is that PRAs publishing benchmark prices undergo an annual assurance review by an external auditor. UK-based privately owned Argus Media, one of three major PRAs – along with US-based Platts, which is part of McGraw Hill, and UK-based ICIS, a division of Reed Business Information, which is part of the Dutch-UK publisher Reed Elsevier – has successfully completed its requirement to undertake this year's review. Other PRAs include US-based Opis and the Japanese firm RIM. IOSCO and the other international organizations will review how the PRA Principles have been implemented in early 2014. Nothing in the G20 process so far has impeded the existing process of identifying oil prices. The European Commission, however, has introduced proposed legislation that poses serious risks to price identification in European energy and commodity markets.

European Commission Regulation of Benchmarks

An understanding of the physical constraints involved in the trading of oil is apparent in the IOSCO PRA Principles but is lacking in the proposed EU regulation. The proposed European regulation will produce energy benchmarks that are not representative, reliable, or robust. Energy benchmarks will become unnecessarily volatile, as the market information allowed to be used to identify prices under the new law would be highly selective and restricted.

The Commission's benchmarks proposal has been drawn up on the assumption that the oil market, and all other commodity markets, are inherently like financial markets. It fails to recognize the more limited liquidity in oil markets, compared with financial markets. The buying and selling of oil ultimately takes place in a physical market that naturally operates with economies of scale, unlike financial markets that do not require the physical transportation of a commodity from producer to consumer. Financial markets trade in small volume lots, trade frequently in discrete units by simple electronic transfer, and do not trade within a physical infrastructure. The proposed European regulation for benchmarks is mainly designed for interest rate and other financial markets and is therefore not appropriate for the oil market, which is ultimately concerned with getting product to a consumer at the lowest possible cost.

The European Commission proposals have been formulated against a political backdrop intent on addressing the so-called 'financialization' of oil markets. But the debate about financialization has now settled on a consensus that stresses the importance of the convergence of derivatives with physical prices for the underlying assets, and the resulting fact that supply and demand are the key drivers of oil markets in all but the shortest term. The European regulation, on the other hand, does not address the physical aspects of oil benchmarks and focuses entirely on derivatives.

Physical Aspects of Oil Benchmarks

A commodity market such as oil emerges from and revolves around the physical infrastructure, which imposes constraints on trade such as limits on quantities, specific delivery times, breakdowns, and delays. European oil markets trade around shipping and storage facilities that result in the creation of large distinct units of purchase and sale – such as large cargoes of crude oil – that can only be transacted between appropriately equipped market participants. The size of trade and timing of delivery vary due to elements such as weather, port conditions, refinery operations, oil field maintenance, industrial action, and other unforeseen disruptions. Another factor that varies in oil markets is quality specification; there are hundreds of grades of crude and a vast range of refined products and blendstocks. Standardized contracts have evolved, but they require flexibility – elements such as quality, volume, and timing of delivery make allowance for operational tolerance.

'The proposed European regulation will produce energy benchmarks that are not representative, reliable, or robust.'

The agreement of purchase or sale is only one small element in a complicated physical transaction that may take weeks to complete. The spot sale is negotiated several weeks before loading, while delivery may be several weeks after loading. Between loading and delivery, transportation must be chartered, quality checked and confirmed, loading or injection must take place, and offtake or delivery must be completed.

All of this makes a European regulation that is designed for financial market benchmarks inappropriate in physical energy markets.

Physical spot commodity markets provide energy to consumers throughout the globe efficiently, allocating products to provide the best value for buyers and the best returns for sellers. The spot price is the element that clears shortfalls and surpluses in each market, mitigating inefficiencies. Spot prices are the outcome of negotiations between buyers and sellers of each commodity in each location, as both sides to a deal seek to maximize value. Transparency in open market pricing allows non-spot transactions, such as longer-term contracts, to settle on agreed prices that represent fair value. The provision of this transparency is the role of PRAs, which identify prices in the open spot market where sellers and buyers discover the price through negotiation. Prices reported by PRAs are for the marginal supplies that are crucial indicators to balance the energy markets.

Impact on Reporting of Energy Prices

The regulation proposed by the Commission would distort the prices published by PRAs, damaging the efficiency of energy markets themselves. Distortion would occur because the reporting of energy prices requires information on transactions and on bids, offers, and other market intelligence underlying the transactional data. PRAs specialize in gathering and reporting this information, but the European regulation would undermine this process.

The regulation would impose extensive legal obligations on the providers of market information to anyone who publishes a benchmark price. Companies involved in producing, supplying, and consuming energy would react to these new obligations, many of which are onerous and costly, by stopping the supply of information to PRAs. This would enable such companies to avoid risks, costs, and administrative burdens while allowing them to continue with their main function – energy production, supply, trading, and consumption. All the information gathered by PRAs is supplied voluntarily by companies in the energy sector, so ending this supply would be the easiest choice for most companies. Companies that trade in physical energy, but do not deal in financial derivatives traded within the EU, would have no incentive to continue supplying information to the providers of benchmarks used to settle the financial instruments, even though these benchmarks are also used in physical trading.

One key obligation that companies would avoid by opting out would be the legally binding codes of conduct with PRAs. Other provisions in the European regulation would impose new internal controls on any company that contributes price information to the provider of a price benchmark. The obligations in the regulation would result in high costs for each company contributing market information, and companies would be unlikely to accept the intrusive nature of the rules. The onerous nature of the obligations on providers of market information could even prevent the production of benchmarks in a timely manner because companies would need to implement so many controls on contributors that information may reach the benchmark provider outside the required timescale for daily publication.

The EU and the International Energy Market

The international nature of energy markets makes the obligations imposed by the European regulation even more inappropriate – many market participants are based outside the EU and would have no incentive to agree to operate under the terms of the new legislation, with all of the obligations it entails. It would not be feasible for a PRA based in Europe to demand that non-EU companies – such as Middle East state-owned producers, Russian trading firms or Indian refiners – sign legally binding codes of conduct under EU law if any of their employees is to be a source of information.

For example, a Russian trading company that acquires diesel from a Russian refinery and supplies it to the structurally short European market would no longer wish to contribute information to PRAs. Such a withdrawal would have far-reaching implications because the company may be selling at the lowest marginal price, thereby helping to determine the clearing or open market price. The PRA would be unable to utilize this price in its benchmark assessment if the Russian company, understandably, had opted out as it was not prepared to take on costly and onerous obligations such as a legally binding code of conduct and new internal controls. The PRA would then face the prospect of publishing a benchmark price based on selective information (that is, information limited to sources that are prepared to accept the costly and onerous obligations of price identification in a heavily regulated environment). This benchmark would thus be distorted by the absence of information from companies such as the Russian trading firm, as well as others as diverse as state-owned companies from north Africa and the Middle East that sell refined products to Europe, state-controlled Chinese trading firms, and Indian or South Korean refiners that export their products to Europe.

'A commodity market such as oil emerges from and revolves around the physical infrastructure, which imposes constraints on trade.'

These companies would soon have a low degree of confidence in benchmarks published in the EU because the benchmarks would only reflect market data contributed by the shrinking group of firms prepared to accept the onerous obligations involved in providing information to the benchmark publishers. Companies that had withdrawn from supplying information to benchmark providers would realize that regulation had resulted in either artificially high benchmarks that reflected mainly price data from higher-cost EU suppliers, or artificially low benchmarks that were biased to buyers' price data. They would become wary of using such distorted benchmarks as indexes in physical transactions. Adding to this wariness, many non-EU state-controlled energy suppliers would mistrust benchmarks that they perceived to be under the control of a large energy consumer – the EU. It would be no different if the tables were turned – EU member states would be uncomfortable if energy benchmarks came under the direct supervision of government agencies in exporting countries. Policy makers in EU member states and the European Parliament should be aware of the political sensitivities of energy pricing.

The Creation of EU and Non-EU Benchmarks

PRAs and market participants would be aware of other prices in the open market that were not reflected in the distorted benchmarks created under the direct supervision of regulators in the EU (involving, as noted above, many costly and onerous regulations on publishers and sources of market data). PRAs would then find themselves in the bizarre situation of having to report two price assessments for the same commodity: a EU benchmark based on information from a small self-selecting group of approved sources operating under EU rules and direct supervision by regulators in the EU, and a non-EU benchmark representative of the open market price, but which the PRA states must not be used as a benchmark except outside the EU.

A two-tiered market of this type – with EU and non-EU benchmarks – would be inefficient, particularly for Europe. Trading and hedging in the EU would be based on benchmarks that did not represent costs and value at the margin. Price discovery and transparency in the EU under the proposed regulation would be inefficient. And, in the end, inefficiency is always paid for by the consumer.

If regulation makes benchmarks unviable and therefore destroys the relationship between derivatives and underlying physical markets, hedging as it is now practised becomes impossible. This would have far-reaching implications for the industry, its corporate energy users (such as manufacturers and other industrial users of energy), and consumers in the real economy in Europe.

Hedging is necessary in energy and other commodity markets because these commodities are delivered in large lots that take time to move between locations that are subject to differing infrastructure constraints. Exposure to time and location must be mitigated, or risk becomes unmanageable for buyers and sellers. Mitigation is carried out through hedging floating costs against fixed benchmark prices. Without hedging, uncertainty and volatility in energy markets are costs that would be passed on to consumers in the EU.

The European regulation applies to benchmarks used in financial instruments in the EU. It asks other jurisdictions to have 'equivalent' systems, but these need not be imposed through legislation, so the EU regulation is almost certain to be out of step with regulatory frameworks in other parts of the global energy markets. This would result in a dysfunctional energy market in which, for example, a physical price index – which does not seek to comply with the EU regulation – could be used to price physical energy transactions within the EU by all companies, but could only be used to hedge price risk by non-EU companies hedging in non-EU venues.

EU-based companies would be forced to use a benchmark for price risk management purposes which was based on the European regulation, even though this index did not represent the open market price and was not used for physical indexation. Non-EU companies selling in Europe would thus be better able to manage their price risk than their EU-based competitors. This would give non-EU companies a competitive advantage and could result in relocations or greater European dependence on non-EU suppliers, to the detriment of Europe's energy security.

'The agreement of purchase or sale is only one small element in a complicated physical transaction that may take weeks to complete.'

The EU would, perversely, end up worse off as a result of one of its own pieces of legislation, if the member states and European Parliament do indeed decide to enact a regulation on benchmarks that may be suitable for financial markets but not for the physical commodity trading sector.

Conclusion

The regulation proposal as it stands will result in confusion in the market. EU companies may be severely disadvantaged compared with non-EU companies. Benchmarks fulfilling the obligations of this regulation will be unrepresentative, unreliable, and not robust. Any benchmarks produced under this regulation will have fewer sources of information than existing benchmarks, with the result that transparency will be reduced. The consequence will be more volatile benchmarks. Other price series are likely to be used as benchmarks to index physical energy, even within the EU, but only non-EU companies will be able to manage price risk using these non-EU benchmarks. In other words, the proposed European regulation, by misunderstanding the nature of the oil market, risks achieving exactly the opposite of its intent. Fortunately, the solution to the conundrum created by this proposed regulation already exists and has been developed and agreed internationally, with input from acknowledged expert agencies in the field. Europe should give its full weight to supporting the implementation of the PRA Principles for oil and all other commodity benchmarks. ■

New EU Rules May Be a Fix for Something That Isn't Broken

PATRICK HEREN

The pricing of oil, gas, and other commodities has been under fierce regulatory scrutiny since 2008. Regulators – especially those in Europe – have focused on the role of Price Reporting Agencies (PRAs) and questioned the subjective nature of their price assessments. The regulatory mind likes tidy methodologies based on 'verifiable' data, and this bias could now be leading to the introduction of tightly prescriptive rules that would seriously distort physical commodity trading and make it less, rather than more, transparent.

The draft European Commission directive on benchmark regulation comes in the wake of the global financial upheavals and is aimed at financial derivatives markets. It appears also to be part of the French-led agenda within the EU to limit the influence of what many European politicians regard as undue Anglo-American dominance of the global economy.

> ***'… oil markets in particular are physical and non-standardized, even though they are capable of sustaining highly liquid futures and derivatives markets.'***

Commission Benchmark Proposals

The Commission's benchmark directive makes a number of unprecedented proposals that, if implemented, would have the unintended effect of reducing transparency in physical commodity markets. Inter alia, the draft suggests:

- That market sources voluntarily providing information to PRAs should be subject to direct regulation by an EU body.
- That no contributor of information should be party to more than 25 per cent of either the volume or the value of transactions used in the calculation of an index. (Such a restriction would make it impossible to provide benchmarks for North Sea crude oil, some refined products, and potentially some natural gas and electricity indices.)
- That the PRAs police their information sources and, where they suspect misconduct, report their sources to the authorities (the EU).
- That the EU would create a category of 'Authorized Contributors'. (These would apparently include physical/industry players and authorized investment firms. Such definitions are unworkable in the wider global arena in which oil, liquefied natural gas, and coal are traded, and in any case would disqualify genuine transactions or market information contributed to PRAs by non-qualifying entities.)
- Finally (and potentially most damagingly) the draft would impose unlimited financial liability on 'Authorized Contributors' in respect of any information they provide. (This is likely to severely discourage the flow of reliable information, on which the PRAs, and beyond them the operation of the free markets, depend.)

IOSCO and PRA Principles

From the energy market's perspective, the Commission seems determined to ride roughshod over other and more coherent regulatory interventions. The most wide-ranging investigation of the role of PRAs was that undertaken in 2011/2012 by the International Organization of Securities Commissions (IOSCO), an international umbrella group primarily concerned with the integrity of securities markets.

IOSCO's probe into the PRAs' role in oil markets, mandated by the G20, was lengthy and exhaustive. It took evidence from about twenty interested parties.

A minority severely criticized the PRAs for being subjective, unprofessional, and open to manipulation.

However a majority of respondents (including, of course, the three principal PRAs) were broadly supportive of the reporting agencies, and warned against any attempt to regulate them.

BP, one of the world's largest and most active oil traders, responded thus:

'We understand the concerns … that the use of PRA benchmarks in the design and pricing of OTC and exchange-traded derivatives contracts may give rise to market integrity issues. However, we do not believe it is correct or appropriate to characterise the activities of price reporting agencies as posing systemic risks or moral hazard to the financial system. It is certainly the case that physical oil markets are important to the global economy; however, the mere fact that PRA benchmarks are reflected in the design or pricing of a commodity derivative instrument does not give rise to the same type of risks as credit maturity transformation activities performed by banks.'

'… it tends to be senior company executives and regulators who prefer transaction-based indices, while traders and others closer to the action see the value of assessments.'

The three PRAs all offered lengthy defences of their methods and output. ICIS – the least influential in the oil market but the leader in gas pricing – made the point that:

'Transparency in physical oil markets is a function of multiple approaches to information: it is not simply the product of number-gathering. Price-reporting services have created transparency by researching, analysing, and publishing information on verified transactions, bid/offer levels, market sentiment, movements in and relationships to other related markets, freight and processing relationships, and derivatives markets.'

The point is that oil markets in particular are physical and non-standardized, even though they are capable of sustaining highly liquid futures and derivatives markets. In fact, the PRAs play a vital role in both creating and sustaining the conditions in which such energy-based securities markets can flourish. They do this by weighing carefully all the information available to them – transaction data (verified and unverified), bids and offers, statistical data (especially that relating to supply and demand), and opinion.

The IOSCO report made many recommendations, and led to a set of principles for Price Reporting Agencies which largely embodied, but also reinforced, the already strict internal governance rules that each PRA had developed over many years. But essentially it gave the PRAs a clean bill of health:

'IOSCO acknowledges that PRAs meet a legitimate physical oil market need, have increased transparency in the markets for physical oil where there are no requirements for transaction reporting to PRAs, have facilitated hedging activities by creating benchmark prices and have, to varying degrees, instituted policies that reflect a concern for quality and integrity in their work-product. … IOSCO also appreciates that PRA price assessment processes involve analyses of complex and varied oil markets and products and produce market views that promote price discovery in the physical oil markets.'

However, one of the areas of concern shared by IOSCO and the Commission is the verifiability of data and, in particular, the transaction data used in assessing prices.

Any competent price reporter knows (a) that it is vital to obtain as much transaction data as possible, and (b) that this is rarely the whole story. That is why, even in highly liquid and transparent markets such as the UK's NBP gas market, PRAs publish both transaction-based indices and bid–offer assessments.

The IOSCO report made its preferences clear, but did not demand full transaction-based price reporting:

'PRAs [should] give priority to concluded transactions in making assessments and implement measures intended to ensure that the transaction data submitted and considered in an assessment are *bona fide*, including measures to minimize selective reporting. These measures are intended to promote the quality and integrity of data and in turn the reliability of assessments.'

Assessment or Transaction-based Reporting?

I can here provide only anecdotal evidence, of the kind deprecated by regulators, but in my personal experience over four decades of energy market reporting it tends to be senior company executives and regulators who prefer transaction-based indices, while traders and others closer to the action see the value of assessments.

Transaction-based indices give a sort of spurious sheen of accuracy, backed up, in the case of those indices generated on electronic trading platforms, with a verifiable audit trail. Understandably, they seem to remove doubt, and above all subjectivity, from the benchmarking process.

Yet even in highly liquid and transparent markets such as NBP or TTF gas, there are usually other considerations which may lead a professional price reporter to assess a closing price, or more importantly, a closing bid–offer spread slightly – usually very slightly – differently from the transaction-generated index.

The proof of the pudding is in the eating. Oil and other energy markets have consistently opted to benchmark to price assessments published by PRAs. Of course, in the real world – and they operate in the real world – they have little choice. Only PRAs can accurately reflect and benchmark the opaque physical markets that underlie the huge OTC derivatives and futures markets that grab the attention of regulators and politicians.

Possible exceptions to this rule are the closed system markets such as gas and electricity, especially the latter. Here the PRAs, face two different challenges, both of which commend themselves to tidy minds.

'Third-party assessment by an agency whose very existence depends on getting it right is absolutely essential.'

Power markets have to balance in real time, and thus tend to produce prompt indices of undoubted accuracy. However, PRAs provide most of the transparency along the electricity forward curve, and thus their skills and published assessments are vital to this sector.

In European gas, the challenge comes from brokers who have overcome their innate mutual suspicion to pool transaction data in the so-called Tankard Index (named, it is said, from the silver tankards of champagne being quaffed in a London gentlemen's club by some leading brokers). Tankard produces prices very similar to the PRAs' assessments, but it has not been adopted and seems unlikely to be. The reason is simple: it is owned by brokers and brokers are part of the market, always acting as agents to market principals. That is why broker indices – which have a long history in the oil as well as the gas market – are bound to fail. Ultimately they lack the commitment to impartiality which is the PRAs' stock in trade.

One of the Tankard participants was recently fined $87 million for its part in manipulating LIBOR. There are two lessons to be drawn from this. First, that brokers in any market are bound to be tempted to help their clients manipulate prices from time to time. Second, that a benchmark like LIBOR – or indeed any financial benchmark – cannot be produced reliably by the industry's trade association, no matter what safeguards. Third-party assessment by an agency whose very existence depends on getting it right is absolutely essential.

The energy PRAs have been severely tested in recent years, and they have been subjected to severe regulatory scrutiny from which they have emerged with stronger and more transparent governance. The European Commission's benchmarking directive ignores that history and, by trying to regulate and potentially criminalize information flows, runs the risk of making global energy markets more opaque and more liable to manipulation. ■

Oil Trading on a Sea of Evolving Regulation

DAVID FYFE AND BRIAN LEWIS

Trading and shipping energy commodities is a business that has evolved markedly in the last decade. It is also very different from trading financial derivatives. The range of commodities, participants, and physical infrastructures involved is broad and heterogeneous, compared with more homogenous instruments traded in many of the financial markets. The business model for commodity traders has changed dramatically in the last five to seven years, as companies have invested along the value chain, across geographies, and diversified their product mix.

Contrary to popular belief, commodity traders are already highly regulated, across all spheres of their diversified business. Given their increasing reach and enlarged presence along the global energy value chain, this is as it should be. But financial regulators should be alert to the specifics of the physical oil and energy markets, and to the fact that trading companies cannot be regulated just like financial institutions. Ultimately, incoming regulation needs to avoid unintended and adverse consequences for physical market liquidity, price discovery, and transparency, which could result in higher costs for energy consumers. Physical market participants need to fully engage with regulators and policymakers to ensure the perils of inappropriate regulation are fully understood.

The Changing Role of the Commodity Traders

Commodity trading companies have been around for a long time, traditionally fulfilling a midstream role, deploying extensive logistical capabilities and market knowledge, to bring together producers and consumers worldwide. They have generally remained independent, private companies – a model that has allowed them to retain the flexibility, risk tolerance, and speed of reaction necessary to succeed in diverse and changing energy markets. They are largely indifferent to absolute prices, depending instead on time-, location- or inter-product arbitrages to generate revenue.

> ***'… regulation needs to avoid unintended and adverse consequences for physical market liquidity, price discovery, and transparency.'***

The common perception is that commodity traders thrive on price volatility, and to a degree that is true. But taking their role in the market to its logical conclusion, they also ultimately help re-establish the physical equilibrium normally associated with renewed price stability. Commodity traders have always represented an essential 'lubricant' for the global energy supply chain.

Leaving aside this ultimately self-correcting relationship between traders and market volatility, the physical traders' business model has evolved dramatically in the last five to seven years. The heady days of 2008/2009 price volatility (and buoyant trading margins) have given way to a period of remarkable price stability and intense competition within the trading space. Against a backdrop of a global financial crisis, geopolitical instability, particularly in the Middle East, and macroeconomic concerns within the developed world, Brent crude has nonetheless averaged close to $110/bbl in each of the years 2011, 2012, and 2013. In this low-volatility/low-margin environment, energy traders have sought access to volume and optionality by investing along the supply chain. This has seen them purchase upstream and downstream assets which fit with their existing trading and logistical strengths – creating synergies and optimizing facilities. They have also sought to diversify risks by broadening their product mix and geographical exposure. From a historical role as intermediaries, commodity traders are becoming integrated industrial companies, with shares in oil and gas fields, coal mines, refineries, power plants, and LNG facilities. Trading and logistics expertise help them to improve operational efficiencies and maximize returns from these facilities, but clearly the traders' exposure to price risk has both broadened and deepened. An ability to easily hedge price risk all along the curve, already vital in a cut-throat pure trading environment, has intensified.

The Myth of the 'Unregulated' Trader

Commodity traders, now more than ever, are embedded across the global physical supply chain. In Gunvor's case, total physical volumes are equivalent to 2.5 mb/d of oil. Yet the word 'trader' is taken by many observers and policymakers to signify a group of players solely interested in making speculative bets on the commodity markets. Commodity traders are frequently mentioned in the same breath as – and often considered the same as – index funds, hedge funds, swap dealers, and financial institutions. They are not. There has been much research published on the role of the financial firms and the impact of 'speculative' activity on price discovery and price itself for both commodity derivatives and the associated underlying physical commodity. To be clear: this is not the realm of commodity traders.

Paper market operators can perform a risk management function and, in the case of financial institutions, act as counterparties allowing commodities traders to hedge physical exposure and manage price risk. But regulation applicable to these financial companies' derivative market activities may not be equally applicable to the more diversified physical exposure of the trading houses.

> ***'… commodity traders are becoming integrated industrial companies …'***

Every physical barrel produced, shipped, refined, stored, and arbitraged by traders is already subject to a swathe of industrial best practice requirements, products specifications, environmental, and health and safety controls. Traders deploy rigorous, dedicated systems to ensure due diligence, and for screening counterparties and vessels. European refineries need to address incoming Fuel Quality Directives, Industrial Emission Directives, energy efficiency requirements, marine fuel quality changes, and strategic stock holding requirements. Relationships with international banks for recourse to trading, project, and longer-term finance bring with them increasing openness and transparency. There has further been a move for commodity traders to expand and diversify their funding via public capital markets on transparent regulated exchanges. Hedging activity on regulated markets is transparent and already controlled by the exchanges and by a host of national and international regulators. Commodity trading houses also work with a multitude of regulators globally, who oversee every facet of the traders' business. The question is: will impending derivative market and benchmark rule changes ensure these activities remain *appropriately* regulated?

Unintended Consequences

The financial and economic crises of 2007–2009 rightly led policymakers to try to reduce systemic risk in derivatives markets. But as the economic downturn was also partly caused by surging oil and raw materials prices, parallel policy measures were intended to improve market transparency and price feed-through to consumers, and to render markets less prone to price spikes and volatility. These dual aims in themselves are perfectly laudable and to be supported. However, elements of the new regulations that may affect companies' ability to hedge price risk, amid stretching and more complex supply chains, threaten to undermine governments' goal of more predictable, stable energy markets.

In addition, during the regulatory debate several misconceptions have emerged that need dispelling:

- First, that commodity derivatives markets are somehow identical to financial derivatives markets, and therefore *one-size-fits-all* regulatory measures can be applied to physical commodity markets without adversely affecting market participation, risk hedging, physical and financial market liquidity, or raising energy costs to consumers.
- Second, commodity trading houses themselves are perceived as (a) largely unregulated, and (b) fundamentally not different from financial institutions, and therefore can be subject to the same sort of regulatory regime as banks, hedge funds, and foreign exchange traders.
- Third, there is a fundamental lack of understanding that, unlike financial institutions, commodity trading houses do not carry systemic risk within the financial markets.

The danger is that by accepting these misconceptions, well-meaning measures designed to mitigate systemic risk and tackle market manipulation could ultimately have unintended consequences:

- diminishing, or causing undue concentration in, market participation;
- rendering energy markets less transparent and more prone to price uncertainty;
- ultimately, raising costs for consumers.

So the first policy imperative, designed to address systemic risk in derivatives markets, could actually undermine the second imperative on physical market transparency and volatility.

Key Regulatory Challenges for the Trading Community

Traders willingly comply with regulations that ensure the safe, timely, and legal carriage of commodities from A to B. They have every interest in ensuring robust price benchmarks and transparent reporting to Price Reporting Agencies (PRAs), and that the potential for manipulation in derivatives markets – and systemic risk in the broader financial sphere – are minimized. Traders are, more than ever before, an integral part of the physical energy supply chain and users of the global financial system.

At the same time, regulators need to recognize more fully that physical commodity markets are not identical to those for purely financial instruments. Indeed, there are also fundamental differences within the commodity derivatives markets between oil, power, gas, metals, and agriculture. Commodity traders are not banks and should not be regulated as if they were. Regulation that works well within the specificities of the gas and power markets, such as REMIT, may not mesh so well with the peculiarities of oil. Rules covering market abuse and market manipulation will apply equally to financial institutions and commodities traders. As commodities traders whose core business is moving energy from A to B, we are subject to precisely the same laws, rules, and regulations as financial institutions who are active in the physical commodity space. In reality, a *one-size-fits-all* regulatory approach may minimize the task and cost of oversight for regulators, but it is unlikely to help optimize energy market function.

Exemptions for commercial participants from swap and position limit rules may help recognize the needs of physical market players. But with broad cross-product and cross-geography exposure and supply chains that run anywhere between 20 and 90 days, across continents, the need to quickly and flexibly hedge highly specific market exposures is clear. The move on-exchange of standardized OTC instruments may have improved the visibility of trades. Arguably it may have also diminished the ability of some smaller traders to find tailored risk management solutions for non-standard products and cargoes, with the potential consequence of them ceasing to hedge. This therefore increases risk for these firms. All told, the breadth and depth of new derivatives, physical, environmental, trading, and benchmark-related regulation under preparation for Europe, the USA, and Asia will have a profound impact across the commodity trading business.

'… regulators need to recognize more fully that physical commodity markets are not identical to those for purely financial instruments.'

There are many different aspects of the new regulation. These range from being able to appropriately manage price risks and industrial sites, the use of, or contribution to, a commodity benchmark, managing risks along the transaction chain, to ensuring readiness for transaction reporting requirements under these new regulations. A bit like the oil markets themselves, there is a lack of consistency in these requirements, and this poses challenges and risks to commodity traders. As with all things, the devil is in the detail.

Engagement and Influence

This is not to argue against regulation *per se*, merely to highlight the wide range of concerns surrounding potentially inappropriate regulation:

- an ability to adequately and economically hedge risk is essential for physical market players;
- discouraging hedging potentially encourages unwarranted market volatility;
- a lack of international regulatory harmonization itself represents a market distortion;
- driving smaller market participants out of business due to increased compliance costs, or diverting resources away from the 'bread and butter' business of supplying energy, could raise costs to consumers and increases risks for the companies that remain.

As such, it is incumbent on physical market participants to engage with policymakers and financial regulators to ensure the latter are aware of the complexities of the markets in which traders operate. After all, a robust, internationally consistent regulatory system, which reflects specific market conditions and realities, while at the same time promoting healthy growth in global energy trade, is in everyone's interest. ■

Fundamentals, Markets, and Price Discovery

ROBERT LEVIN

Increased oil production in North America during recent years has been well publicized, not only by oil analysts who follow such events closely, but by mainstream media and press; it is an ongoing international news story.

The US Energy Information Administration (EIA) reports that, since 2005, Canadian oil production has increased steadily by 1 mb/d. In the USA, production has risen by more, and at a faster rate – 3.5 mb/d in less than five years. Most of these increases are located in the mid-section of North America. This has led some reputable institutions (and analysts) to project that by 2020 the USA will be the world's largest producer of crude oil (a status some already assign it for combined oil and natural gas production). Regardless of the actual ranking of US production compared to others, there can be no dispute that North American production has increased significantly, is expected to continue increasing significantly for the foreseeable future, and constitutes a significant component of international fundamental supply and demand for oil.

Price Impacts

All other things being equal, the increased production in North America should have led to lower crude oil prices in North America versus the rest of the world. Furthermore, given the rapid continuing decline in North Sea production that predates the increased production in North America, North Sea prices relative to North American prices should have increased. Of course, as always in the real world, it is not the case of 'all other things equal'; although enough stayed 'equal' for it indeed to be the case that North Sea prices rose relative to US prices, not all such impacts have been equally incurred or sustained during the entire period.

'This has led some reputable institutions (and analysts) to project that by 2020 the USA will be the world's largest producer of crude oil.'

Part of the reason for this is that expansion of the oil distribution system in North America trailed expansion by the oil production system by one to three years, depending on who is doing the counting and how they are doing it (there are some market observers who, if held strictly to what they reported in the past, come closer to estimating a lag of six to seven years, but objective facts summarily reject that). During this period, however long one assesses it to be, Midcontinent North America supply increased relative to US Gulf Coast supply and prices reflected it. A logical consequence of this, completely consistent with the fundamentals, is that the differential between Midcontinent and US Gulf Coast prices for crude oil widened in favour of the Gulf Coast. For instance, using Refiner Acquisition Cost of domestic produced crude oil reported by the EIA, beginning in Spring 2011, the differential increased to about $5/barrel, and eventually reached $19/barrel during Fall 2012, immediately prior to the implementation of the Seaway pipeline reversal that increased flow capacity from the Midcontinent to the Gulf of approximately 400,000 b/d.

After the Seaway reversal, which is only part of the increased flow capacity from the Midcontinent to the US Gulf, the differential quickly decreased, reaching about $2/barrel in June and July, the two most recent months for which these data were reported at the time of preparing this note; $2/barrel is slightly higher than where the relationship stood before Spring 2011, but is very close. (I used Refiner Acquisition Costs (RAC) because they are documented and authorized by the EIA and represent what refiners actually paid for their crude oil. Notwithstanding, it is highly likely that the distribution of crude streams included in these data changes from month to month, so these data do incorporate changes in specifications that are not accounted for. Using an alternative stream of prices, such as reported spot prices, entails comparable, if different, compromises in data consistency. The overall purpose here is to give an indication of the scope of the relationship between Midcontinent and US Gulf prices, and RAC does that.)

Price Analysis North American Crude Oil

An attractive and commonly accepted feature of the US market is that US crude oil prices, including WTI, reliably reflect fundamental supply and demand. In large part, the commercial market is expressly structured and organized to accomplish this. The market mechanisms, including delivery components, of the commercial US oil market are based on straightforward designs, intended to attract participation and support and build commerce; they are uncomplicated and lack artificial barriers to entry, and this leads to active arbitrage across the vast distribution system. The result is that US commercial markets are directly accessible to thousands and, driven by arbitrage, incorporate significant levels of transparency and competition.

Accordingly, prices respond to supply, demand, and competition – exactly what Midcontinent and US Gulf supplies are experiencing and what we illustrated above. The reason prices have converged is because the capacity to move crude oil from production areas in the Midcontinent to the rest of the USA, including the Gulf Coast, has increased dramatically – by nearly 2 mb/d over the past several years, with an additional 1.5 mb/d to the US Gulf to be added during Q4-13 and Q1-14. The EIA reports that rail cars are transporting 1.4 mb/d as of mid-2013. As mentioned earlier, the Seaway reversal added 400,000 b/d capacity to the US Gulf and the looping of its lines is scheduled to double that during Q1-14. The Southern leg of the Keystone pipeline is scheduled for completion during Q4-13 and should ultimately add 750,000 b/d capacity. In addition, the Magellan pipeline is scheduled to bring on another 250,000 b/d of capacity in Q1-14. The market has fully embraced the additional capacity and will continue to do so as even newer capacity is added.

The EIA also provides a historical record of pipeline, tanker, and barge movements between PADDs; it has not yet been able to incorporate the rail car movements into this specific record series. Until recently, the flow from the US Gulf to the US Midwest dominated the reverse direction. According to the EIA, as recently as 2005, there were months in which more than 2 mb/d of crude oil flowed from the Gulf to the Midwest. This has steadily declined since then, but it is still the case that monthly flows average from 860,000 b/d to over 1 mb/d (Q4-12). These fundamental data are consistent with the other fundamental observations about increased production; clearly, the need to 'import' crude from the US Gulf to the Midwest has diminished as Midcontinent production has increased.

'US crude oil prices, including WTI, reliably reflect fundamental supply and demand.'

Moreover, the reverse flow – from the US Midwest to the US Gulf – has increased steadily since US production began rising in 2008, shooting up in particular during 2013. According to EIA, in January 2008 the flow was 63,000 b/d; in both March 2013 and July 2013 (the most recent month for which data were available at the time of preparation of this note) the rate was over 500,000 b/d. The increased pipeline capacity scheduled for Q4-13 and Q1-14 mean the conditions are set in motion for this to increase further easily.

On top of this, from March through July this year (the most recent months such data were available at the time of composing this note), EIA reports that imports of crude oil into the US Gulf have decreased by 1.8–2 mb/d since 2010, which clearly impacts markets outside the USA; in other words, the supply of oil to the rest of the world – conceptually from the US Gulf – has increased by nearly 2 mb/d over the past three years. Increased US supply is directly and significantly impacting world supply.

All of these referenced data sets represent standard fare for the US market; market participants understand that they have ready access to a trove of reliable fundamental market data to analyse opportunities and challenges and compete to perform arbitrage. From the perspective of fundamental market supply and demand information, US market participants are extremely well-informed, indeed the best-informed in the world by a wide margin. In addition to what is referenced above, there are well-known series on weekly inventory reports for crude and products, each region (including Cushing, Oklahoma, the delivery and pricing point for WTI), and the entire USA. These data are delivered within three business days, which makes them approach the equivalent of real-time information for fundamentals. (Private vendors provide technologically robust services which deliver estimates of these data to their clients in less time.) In addition, market participants have access to weekly updates of refinery inputs and capacity utilization on a regional and national basis.

'US market participants are extremely well-informed, indeed the best-informed in the world by a wide margin.'

One conclusion to draw from the trove of data easily accessible to all US market participants is that US oil markets, governed by arbitrage, cannot elude the discipline of fundamental supply and demand. Our own reference to the relationship between the US Midcontinent and Gulf Coast served as an illustration of this point, demonstrated with three different types of data streams for each location. (The data streams include production, price, and movements. In addition, a fourth stream applied to the Gulf Coast imports.) So far, we have added to the well-documented historical testimony that US oil prices, including WTI, are driven by arbitrage and are highly responsive to fundamentals that are transparent, as well as being supported by underlying commercial market mechanisms that are also fundamentally transparent and fair. Is this how it works for other markets and 'benchmarks'; for instance, how does it work for the North Sea?

North Sea Fundamentals?

A fair starting point is to attempt to identify a relationship for North Sea oil and fundamental supply and demand information comparable to that which exists for US crude oil markets, including WTI. Now, one very important piece of fundamental information is provided once each month, in advance, by the commercial producers: the production and loading schedules for the respective crude streams. Beyond that, fundamental supply and demand information for the North Sea does not exist in terms of the detail and timeliness for which it exists for the USA. Nobody in authority compiles such fundamental information for the North Sea. The International Energy Agency (IEA) does compile fundamental supply and demand information and provides a substantial amount of valuable analysis of the world; but its data flow has a substantial lag of more than three months, when taking revisions into account. However, there is no official source of fundamental supply and demand information for the North Sea, beyond the scheduled loadings and a summary report of production by the IEA (with its lengthy lags), and this does not always detail its 'BFOE' components (Brent, Forties, Oseberg, and Ekofisk, the constituent streams that currently make up what is colloquially referred to as 'Brent' in the oil market). There is ambiguity in what should define North Sea fundamentals. The proof of this is that there is no shortage of subjective ruminations about the BFOE market, many of which are very insightful, but those ruminations are dominated by unconfirmed reports of commercial activity and inferences thereof, rather than by objective supply and demand information; all of this constitutes market commentary rather than market fundamentals.

This does raise two related questions: if there essentially is a lack of objective fundamental information by which to measure BFOE's price movements, how can one confirm that BFOE is driven by fundamentals? Also, if BFOE pricing were not driven by fundamentals, what is it driven by?

BFOE Cash Forward and Physical

The BFOE 'market' is mired in layers of different instruments or mechanisms. Most of the layers have been added over time as part of an effort to cope with diminishing North Sea oil production. Our focus is on two very important layers: the BFOE cash-forward market – full cargos – which is the traditional core of the BFOE (and its predecessor Brent) market and the Physical Cargo market – Dated BFOE. We will actually look closely at the Platts Dated price because it is *that* reference that is incorporated into almost all the actual Dated Physical cargo transactions as well as many pricing formulae used by national oil producers to price their oil. The relationship between these two mechanisms is straightforward, but indirect; Platts Dated is not directly related to BFOE forwards:

- BFOE cash-forwards are forward contracts for 600,000 barrel cargos to be delivered at the loading terminal for B, F, O, or E at Seller's discretion during the delivery month. The Seller owes the Buyer a minimum notice period – currently 25 days – that the delivery will take place.
- BFOE Dateds are the same BFOE cash-forward contracts after the Seller has provided the Buyer with the *date* of loading for the contract. They are referred to as *physical* cargos because they are legally

destined to be loaded and delivered with physical oil. (Historically, forwards, by contrast, were easily offset and – essentially, if not technically – liquidated.) Dated contracts are typically priced at a differential to Platts Dated prices for a series of days.

- Platts Dated price assessments are published daily. It is our understanding that they are derived from two of its Market on Close (MOC) price discovery mechanisms: the Partial Brent Forwards, and the CFD (contract for difference) between Partial Brents and Dated Brent. (This is literally the difference between two component legs; here one leg is Partial Brent Forwards and the other is Dated Brent. If you add this CFD to the price for Partial Brent Forwards, the sum is, by mathematical identity, Dated Brent, or more formally, Platts Dated Brent.) Partial Brent Forwards are cash-settled obligations between any matched Seller and Buyer for 100,000 barrel equivalent obligations. They are cash-settled, equivalent to Swap transactions, using Platts' Partial Brent assessment as the floating price with one exception: if the same counterparties enter into six transactions with each other for the same contract month, they are obligated to turn the six obligations into a full forward cargo contract (Platts has assured us that this happens more than occasionally and market participants abide by the rule). Nobody suggests that this is the usual outcome but it does occur. The second price discovery mechanism (the CFD between Partial Brents and Dated Brent) is exclusively cash-settled. When one adds the 'prices' from each of these 'markets' – the sum of Partial Brent with the difference between Partial Brent and Dated Brent – one derives (by mathematical identity) Platts Dated Brent (it is also our understanding that Platts takes into account adjustments in time value extrapolated from its MOC transactions and assessments). Accordingly, Platts Dated Brent, the most commonly utilized reference for Physical BFOE contracts, is derived from two series that are structured to cash-settle; one which always does so, and the other which does so most of the time, with some exceptions.

The Partial Brent and CFD MOC price discovery processes are clearly important mechanisms crucial to pricing the physical BFOE market. One of them entails a possible delivery obligation, but only as an unlikely coincidence. The other entails no delivery obligation. Furthermore, the price discovery processes are not specifically market mechanisms; they support transactions and bids and offers, but these mechanisms are expressly designed to discover value at a defined moment in time. The transactions and bids and offers are tools to reach that goal. By comparison, markets are expressly defined by their bids, offers, and transactions, and one of the market outputs is discovered value (CME Group listed on its NYMEX market a futures contract that cash-settled against the Partial Brent assessment. It should be clear that none of the observations expressed here is intended as criticism. The NYMEX contract reflects an endorsement of the assessment and its market relevance).

As such, are these price discovery processes driven in a similar way to those in the US oil market – participants comparing physical delivery alternatives and performing arbitrage to determine prices? It is not clear that there is a role for arbitrage in these processes. This is not to suggest there is anything inappropriate in this but, if there is no role for arbitrage, is there a role for market fundamentals? There really is nothing that compels physical market supply and demand discipline to be administered through these mechanisms. 'Bids' and 'offers' can reflect views and expectations of market fundamentals and may incorporate them, but there is no physical market consequence if they do not. It is our understanding that, ordinarily, the MOC assessments against which transactions are cash-settled are endogenously determined within these processes without any specific regard for market fundamentals. Unlike market mechanisms with either physical delivery obligations or cash-settled mechanisms calibrated to physical market transaction values, these are pure price discovery mechanisms that can apparently be independent of physical fundamentals. To the extent they are independent, they essentially amount to being an elaborate price negotiation platform; constituting a sophisticated means by which Sellers and Buyers will determine sale and purchase prices, ultimately for physical oil that uses this series as a price reference. And the continuing reliance by market participants on such mechanisms to serve as a base reference price for other important transactions constitutes a strong endorsement of their value; but does it mean they reflect market fundamentals?

'There is ambiguity in what should define North Sea fundamentals.'

Do BFOE cash-forward cargo transactions ultimately govern Platts Dated BFOE? One of the difficulties in trying to answer this is that the cash-BFOE market conducts itself non-transparently; very few transactions are publicly reported so there is no public window by which to view any possible price discovery. By comparison, Platts conducts its price discovery processes with a high degree of transparency. Sidestepping the lack of BFOE forward market transparency, the arbitrage that could take place would be between the forward cargos and the dated cargos. One would expect some degree of convergence to take place between the forward and dated markets, but the lack of transparency of the forward market makes it difficult to uncover any supporting evidence. At the same time, no such convergence needs to take place between the Platts Dated and BFOE Forwards. Consequently, there really is no arbitrage mechanism between Platts MOC price discovery mechanisms and the BFOE cargo market. Accordingly, it is difficult to envisage what principles would govern Platts Dated calibrating in lock-step to price impulses from the BFOE forward market.

By process of elimination, this would suggest that Platts Dated's price discovery processes may lead the BFOE forward cargo market. Whether they lead or not, they do not seem to follow. Outside of negotiation motives, there do not seem to be obvious governing principles to these processes, including any predicated in fundamental supply and demand.

Stalemate

Technically, we will have to consider this quest unresolved for now. But it is an interesting endeavour. We still need to define what constitutes the relevant fundamentals for the North Sea and see if those fundamentals are actually ever assembled or calculated. In addition, we still need to determine what are the prime driving forces in the North Sea market and whether fundamentals are at the core or something else altogether.

It does appear that we can state that US market benchmarks incorporate arbitrage from the physical market, reflect fundamental supply and demand, and are subject to confirmation of this by a substantial catalogue of authoritative data. With respect to North Sea benchmarks, the role of arbitrage, and how and if it reflects market fundamentals, is not so clear; and there is a lack of authoritative data by which to confirm performance. ■

From Macro to Micro: the evolution of the Brent benchmark

AMRITA SEN

Over the past two decades, global crude markets have relied on a small set of key benchmarks as the main pricing tools, and in the western hemisphere, the key index crudes have been WTI and Brent. Indeed, global benchmarks are thought to reflect world supply and demand fundamentals. But since the US tight oils boom, WTI prices have been increasingly governed by the infrastructural logistics of the US Midwest and the position of WTI as an international benchmark has changed.

The market, as a result, has become increasingly reliant on Brent as the primary global benchmark, with open interest in Brent growing strongly since the WTI dislocation began. With two-thirds of seaborne traded barrels priced off Brent and Brent reflecting global supply–demand balances and geopolitical events more aptly, consumers, producers, funds, and even commodity indices started to move away from WTI towards Brent. However, over the course of this year, a few key changes have started to impact the Brent contract specifically, and may somewhat redefine the influences underpinning movements in the Brent term structure going forward.

The strength in Brent prices early in the year was down to global factors – a combination of improvements in the macroeconomic picture, together with OPEC and non-OPEC supply shortfalls. But even as global fundamentals improved, Brent-specific fundamentals started to weaken by mid-year. Starting with North Sea production, the 0.12 mb/d Elgin and Franklin fields, which had been offline for a year, returned to operation in March. At the same time, refinery maintenance was in full swing in the Atlantic basin, reducing spot demand for crude. But the three factors that have perhaps had the biggest impact on the Brent market are the South Korean government closing a tax loophole which reduced South Korean buying of Forties crude, weak European refinery margins putting pressure on light crudes in particular, and the introduction of the Platts escalator, which increases the number of crude grades that can be used to establish the underlying price of Dated Brent. It took substantial outages in light sweet crude from Libya to shore up Brent prices in Q3-13 but as the worst of the outages impacting light sweet crudes eased, the Brent structure came under pressure once again.

> ***'The market, as a result, has become increasingly reliant on Brent as the primary global benchmark.'***

South Korean Buying

After the Free Trade Agreement (FTA) between South Korea and Europe was implemented in 2011, South Korea started to pick up Forties cargoes as they became cost effective adjusted for the lack of import duties under the FTA. Prompt Brent spreads moved into backwardation and, after a few occasions when South Korea took Forties cargoes even when the arb seemed closed on paper, the extent of the backwardation became more entrenched (Q3-12 onwards), with the market fearful of shorting the structure, given the nature of Korean buying. Separate from the FTA tax rebates, South Korean refineries are also eligible for a 3 per cent tax rebate on oil products they export; however, that rebate only applies to products refined from crudes they have purchased and on which they have paid taxes, and thus does not apply to FTA crudes like the North Sea (as these crudes are exempt from the import tax). The South Korean refineries were claiming taxes back on products even when produced from FTA crudes and the government closed this loophole earlier this year. Following this move by the government, the Koreans significantly reduced their purchases of Forties and only returned to the North Sea market for large volumes in September when Middle Eastern crudes reached near-record strength. As a result, the nature of Asian buying of Forties has changed significantly when compared to the last few years. It has become more price-sensitive and will increasingly be a swing factor impacting Brent structure and Brent–Dubai spreads, rather than the constant it was for most of 2011 and 2012.

'… global refining capacity has increased far too quickly, with refinery capacity additions outstripping demand growth for 2013 and 2014.'

Weak European Refining Margins

In the absence of Asian buying, Brent is more exposed to European refining margins, which have been some of the weakest in the world. European refineries are well known for producing too much gasoline relative to diesel, which is where domestic demand is biased, while gasoline demand is declining in the USA, their primary export market. But Europe's predicament is made worse by changes taking place in the products market and the abundance of light ends, brought about by the booming US refining industry, thanks to the access to cheap domestic crude. This has resulted in gasoline exports from the Gulf Coast to Latin America and even Africa – regions that used to be European strongholds. Worse, Europe is a large exporter of naphtha to Asia and naphtha is probably the weakest part of the barrel currently. Seasonality of cracker maintenance aside, a significant change in the markets has come about with the surge in US propane exports, which are increasingly heading to Europe, displacing the more expensive naphtha feedstock wherever substitution is possible. By the end of 2013, the USA could have as much as 15 per cent of the global LPG export business. In any case, growing tight oils, NGLs, and natural gas output is helping to resurrect the US chemicals and petrochemicals industries, and growing ethylene production was already going to weigh on Asian and European crackers that rely on naphtha for feedstock, potentially leading to their closure. The falling away of gasoline and naphtha demand – the key drivers for the sustainability of European refineries – is putting significant pressure on light end prices, the mainstay of European refining margins, and hence demand for Brent.

Moreover, global refining capacity has increased far too quickly, with refinery capacity additions outstripping demand growth for 2013 and 2014, by 0.8 mb/d and 1.5 mb/d respectively. New refineries in non-OECD countries (more often than not supported by government subsidies) tend to run even when margins are weak and are therefore likely to add to the glut in products. Despite some apparent commissioning hiccups, the new Satorp refinery at Jubail in Saudi Arabia will soon make its presence felt on the global market. The emergence of yet another major ultra-low sulphur diesel (ULSD) producer on top of growing Chinese ULSD production and increasing volumes of higher quality product from Russia will not only weigh on outright diesel prices but is also likely to compress the spreads between ULSD and higher sulphur gasoil, and between gasoil and Brent. Barring significant refinery problems, European refiners will not be able to count on strong diesel prices to the extent that they have in recent years to offset weak or negative returns from other products such as gasoline, naphtha, and fuel oil. The bottom line is that the burden will fall on the comparatively more efficient refineries. The problem for Europe is that the least profitable refineries are unlikely to close down, due to government pressure to maintain employment, so refining margins must decline further to levels where larger and more competitive refineries in countries like the UK and USA are forced to shut down. Refining margins will be a constant factor impacting sentiment about the structure of the Brent curve, given the start-up of a tranche of new refining capacity and its negative impact on European margins.

Changes to the Platts Escalator

The third important factor impacting the Brent structure is the introduction of the Platts escalator for assessing Dated Brent prices in June this year. This new quality premium effectively broadens the production base that is used to set the benchmark physical crude price for the Atlantic Basin, thereby reducing the reliance on Forties – the grade that has been the marker for Dated Brent for the last few years and has tended to distort price assessments due to tight supplies. For instance, when the Korean arb was one of the largest determinants of Brent spreads, the escalator would have reduced that impact, making expiries and prices movements less sharp.

'As a benchmark, Brent is still responsive to global supply and demand fundamentals. However, the three factors outlined here, and in particular European refining margins, set the stage for a considerable increase in the volatility in Brent time spreads.'

Under Platts' methodology, quality premiums for Oseberg and Ekofisk are set at 50 per cent of the net price difference between these grades and the most competitive grade of crude among Brent, Forties, Oseberg, and Ekofisk during the previous two trading months. Two-thirds of the quality premium is determined by the spread in the month immediately preceding the current trading month. The remainder of the premium is determined by the spread two months before the current trading month. This methodology generated large premiums for Oseberg and Ekofisk in October for instance, since both grades were very strong relative to Forties in the summer, weighing on Brent prices since Oseberg set the price for Dated Brent for most of the month. When the market for North Sea crude is strong, these quality premiums often play a limited role in setting Dated Brent given the wide difference in price between Oseberg and Ekofisk and the lower quality Forties grade, which usually sets the Dated Brent price. But when demand for North Sea crude oil weakens, and the relative value of Oseberg or Ekofisk to Forties declines, the mechanism widens the slate of cargoes that set the Dated Brent price, compounding the weakness in the benchmark. In a sense, a weakness of the quality premium mechanism is that it amplifies downward trends during periods of soft demand that follow periods of strong demand, yet it does little to curb upward price trends during peak demand periods.

Conclusion

As a benchmark, Brent is still responsive to global supply and demand fundamentals. However, the three factors outlined here, and in particular European refining margins, set the stage for a considerable increase in the volatility in Brent time spreads. We have seen already that, in the absence of Asian and European refiner buying, Brent is vulnerable to rapid shifts in term structure as unwanted cargoes pile up. This looks to be the pattern that will continue to play out as the market struggles to adapt to the problem of global refinery overcapacity. With European crude oil processing rates low, the scope for a quick increase in runs is considerable, but margins are vulnerable to an uptick in refinery production while demand growth remains slow, so increased crude buying is likely to stop as quickly as it starts. There are considerable ramifications to the Brent structure being dictated by increasingly variable European crude demand, particularly if European crude prices have to push lower to sustain arbitrage trade to Asia. At times of the year when there are limited prospects for gasoline demand (Q1 and Q4, for example) Brent spreads will probably face a tough slog, punctuated by periodic bouts of strength as refinery outages or sliding crude prices spur opportunistic buying. Overall, in the absence of unplanned production outages of light sweet crude, Brent spreads could be stuck in the doldrums given these recent changes. ■

Towards a Middle East Trading Ecosystem

OWAIN JOHNSON

DME Oman is emerging as a powerful third benchmark for global crude oil trade alongside WTI and Brent. The recent sharp upturn in trading volumes on the Exchange has been in part driven by improvements in the way the DME operates but is also due to two powerful additional factors: regulatory headwinds that are encouraging market participants to opt for regulated futures benchmarks and, secondly, a drive from Asia to establish its own crude oil benchmark.

> ***'… the region's import–export dynamics have been changing rapidly and this is leading to the development of different trading practices and to a need for new benchmarks.'***

The DME is also benefiting from the development of a genuine trading hub in the United Arab Emirates, with a large number of trading houses and brokers establishing operations in Dubai. The Dubai–Abu Dhabi corridor is already well established as a regional financing hub, while substantial investments in infrastructure in Fujairah and the upcoming Ras Markaz Crude Oil Park in Oman are providing the physical underpinning that will support the further development of the Gulf markets.

The Mideast Gulf has traditionally been considered solely as a supplier of unprocessed hydrocarbons in the form of crude oil and LNG. Domestic markets were traditionally short of refined products but until recently were relatively small. However, in recent years the region's import–export dynamics have been changing rapidly and this is leading to the development of different trading practices and to a need for new benchmarks.

Domestic demand for energy in the Gulf Cooperation Council (GCC) countries is booming as populations grow sharply. GCC population growth is 3.2 per cent per annum compared with the global average of 1.2 per cent. The population growth is exacerbated by high energy demand use in the GCC, with the population of the Gulf poised to surpass the USA as the world's most intensive users of electricity.

The need to supply a booming domestic market has led national oil companies (NOCs) in the region to invest heavily in the development of refining capacity. Between 2014 and 2017 an additional 1.6 mb/d of refining capacity is expected to come on stream, according to consultants Facts Global Energy.

This additional capacity should convert the region in the medium term into an export hub for some refined products as well as enabling some crude oil exports to be diverted into the domestic refining complex. These new dynamics are also presenting trading opportunities to NOCs, leading to the establishment of firms such as Oman Trading International and Saudi Aramco Products Trading Company.

A Post-Dubai World

As the GCC grows in importance as a trading hub and as activity increases on what has been termed the New Silk Road between the Middle East and the north Asian economies, the significance of the region having its own pricing points has also grown.

The Mideast Gulf has traditionally used either Singapore or Rotterdam-based pricing for its refined products markets while for crude oil, regional players have used assessments of Middle East crude oil established by predominantly Singapore-based traders and assessed by the price reporting agency Platts.

It is hard to imagine that this reliance on external pricing can long survive the development of a vibrant trading scene in the Middle East. The supply–demand balance for fuel oil at Fujairah, for example, is so different to that in Singapore that relying on pricing from Asia as a basis for trade means that differentials have to be constantly adjusted to bring outright prices into line with where the outright market in Fujairah is trading.

Of all of the pricing benchmarks in the Middle East, the Dubai crude oil assessment is perhaps the most vulnerable to the new trends in both regulation and the development of an indigenous trading ecosystem within the Middle East. The Dubai assessment process suffers from both low levels of trading activity and from very low numbers of participants, with many segments of the crude oil market not represented in price determination.

New Contenders Emerge

Many parties, including ourselves at DME, are positioning themselves for a post-Dubai world and the issue of the 'third benchmark' – the Asian equivalent of WTI and Brent – has become a staple discussion point for boardrooms and industry conferences alike.

DME is currently the leading contender as it has a track record of six years and enjoys the support of the world's largest commodity exchange, the CME Group, and of Oman, which is the largest non-OPEC producer in the Gulf. The DME's price settlement process – the average of all trade taking place at 4.25–4.30 p.m. Singapore time – also involves a large number of participants (some 65 firms have participated at the time of writing) from multiple market segments. By comparison, the Dubai pricing mechanism can have as few as two or three participants and regularly does not trade at all.

Rarely a month passes at present without another candidate being mentioned as a potential replacement for Platts Dubai. The Shanghai Futures Exchange is planning a medium-sour futures contract, which is likely to launch in 2014, while Iraq, Russia, and Malaysia have all expressed interest to a greater or lesser extent in seeing their crude oil streams used as the underpinning for a futures market that could provide a new oil benchmark for Asia.

No doubt more will emerge, but it is illustrative to note that all of the various options share two core characteristics: they are based on physical delivery and they mostly expect to incorporate a pricing mechanism that is listed on a futures exchange.

'Convergence with the underlying physical market is clearly crucial to ensuring the long-term success of an oil futures benchmark.'

It would appear that the current regulatory environment makes the emergence of a new benchmark that is not regulated, or is based on voluntary submissions, look improbable. Where such benchmarks are already in use, they will likely remain in place. But it is hard to imagine that an emerging energy commodities market would adopt such indices where a more regulatory-friendly alternative is available.

Physical Convergence

Convergence with the underlying physical market is clearly crucial to ensuring the long-term success of an oil futures benchmark.

Oman futures converge smoothly with the physical market. In fact, DME delivers between 12 and 16 million barrels of Oman Blend crude oil every month, the largest physical delivery of any energy contract in the world. This is equivalent to around half of all Omani production.

We can see from the recent contortions in the Brent futures market the difficulty of smoothly operating a financially settled oil futures market when the settlement index is forced to constantly evolve. Oman and WTI have avoided this by settling directly to physical delivery, rather than outsourcing the delivery process. Both Oman and WTI are also fortunate in this sense that they both benefit from rising underlying production, unlike the North Sea complex which continues to experience dramatic production declines that require frequent revisions to underlying contract specifications.

The Brent mechanism will eventually run out of options in regard to North Sea solutions to maintain its benchmark status, while the uncompetitive position of the European refining industry – as highlighted by the recent industrial dispute and near closure of the UK's Grangemouth refinery – puts a further question mark against that particular corner of the North Atlantic as a major oil trading hub, capable of producing relevant benchmarks for a global market.

Future Prospects

The recent upturn in Oman futures volumes are in part a result of improved marketing to the energy trading community, but DME is also benefiting from factors outside its control. The regulatory push from OTC to listed futures, and the increased scrutiny on unregulated benchmarks relying on voluntary reporting, are all providing wind in DME's sails.

There are a number of other benchmarks that could emerge in the Middle East and Asia in order to fill the need for a globally relevant third benchmark alongside WTI and Brent. All share the common specifications of physical support and exchange listing. This would appear to be the future for the benchmarks upon which the energy industry relies – tight regulation and a tight convergence with the underlying physical market.

Petroleum Development Oman and its dozen or so partners have made great strides to increase production in recent years, utilizing the latest enhanced-recovery techniques and developing new fields. Omani oil production hit a peak of 970,000 b/d at the turn of the century, and is on course to hit a second peak with production in September 2013 back to 950,000 b/d, of which around 750,000 b/d is available for export.

'This would appear to be the future for the benchmarks upon which the energy industry relies – tight regulation and a tight convergence with the underlying physical market.'

Oman is also strategically positioned outside of the Strait of Hormuz, the transit point for over a third of the world's seagoing crude oil which is often cited as the world's most vulnerable chokepoint. As such, Oman would escape any geopolitical friction that could disrupt the flow of oil through the narrow body of water, further enhancing Oman Blend's benchmark status.

The Oman Blend is the most widely traded and transparent crude oil grade in the Mideast region, supporting not only an active futures contract but also a healthy secondary market where cargoes are regularly sold and resold. Oman has overtaken Dubai on almost all of the key metrics regarding production, trading, and transparency, as the Dubai crude oil stream is now reduced to just four cargoes per month. In fact Oman is now largely the mainstay of the Dubai pricing mechanism and is a ready-made replacement for the legacy benchmark as it eases its way into retirement. ■

Russia's ESPO Crude: a new benchmark for Asia?

JAMES HENDERSON

The Asian energy market is becoming an increasing focus for the Russian government and its major oil and gas companies as they seek to diversify their export revenues away from western markets and exploit the rapid growth being seen in the East.

> ***'Russian authorities are now actively considering the possibility that its ESPO crude could become a new benchmark in the Asian region.'***

This trend was first established in the 'Energy Strategy of Russia for the period up to 2030', published in 2009, and has been further emphasized by President Putin in his State of the Nation speech in 2012, when he stated that 'in the 21st century Russia's development is vectored eastwards' while underlining that from an energy perspective 'Siberia and the [Russian] Far East hold colossal potential … it's an opportunity to take a good place in Asia and the Pacific' (quoted in *Interfax*, 12 December 2012). As far as the oil sector is concerned, this new strategic direction is based around the development of a vital new piece of infrastructure, the East Siberia–Pacific Ocean (ESPO) pipeline, which will bring Russian oil direct to China and also to the markets of the Pacific region. The first oil was delivered to both markets in 2009, but so rapid has been the expansion of production and sales since then that the Russian authorities are now actively considering the possibility that its ESPO crude could become a new benchmark in the Asian region, and the Russian Ministry of Energy is actively lobbying in this direction. However, although it is clear that ESPO crude has changed the dynamics of the Asian crude market, and is becoming one of the foundations of Russia's growing energy relationship with China, it is important to consider whether it can really meet the conditions to become a true benchmark crude in the region and provide an additional platform for Russian geopolitical influence.

The ESPO Pipeline and the Expansion of Russian Oil Exports to Asia

The idea of a pipeline from Russia to north-east Asia was initially conceived in the early 2000s by the now defunct Yukos oil company, but following its bankruptcy in 2004 the concept was taken over by state companies Rosneft and Transneft, with the latter being responsible for the country's oil pipeline network. The growing Chinese oil market was always the main target for the pipeline, providing an obvious link between Russia's vast oil resources in East Siberia and China's growing import requirement. As a result, it was natural that Chinese state oil company CNPC should arrange for a $25 billion loan to Rosneft and Transneft to help finance the initial phase of ESPO construction. This financing underpinned the first phase of the project, which comprised a 30 mmtpa pipeline from Taishet, at one end of the existing Russian trunk

Map 1: The ESPO pipeline: phase 1, Taishet to Skovorodino and spur to Daqing in China; phase 2, Skovorodino to Kozmino.

(source: Nefte Compass)

pipeline system, to Skovorodino, just north of the Chinese border, with a 15 mmtpa spur then running into China. The remaining 15 mmtpa of capacity was linked by rail to a new port at Kozmino Bay on the Russian Pacific coast (see Map).

'Russian companies will need to establish a long-term development and production plan for new and existing fields if consumers are ultimately to be convinced that an ESPO benchmark is sustainable.'

This initial system came online in 2009, but was filled with oil so rapidly by a variety of Russian producers that it soon became clear that expansion would be required, and construction of the second stage of the project commenced almost as the first crude was flowing. By November 2012 the overall capacity of the pipeline to Skovorodino had been expanded to 50 mmtpa (1 mb/d), with the rail link to Kozmino Bay replaced by a 30 mmtpa (600 kb/d) pipeline and the port facilities on the Pacific coast expanded accordingly. Exports have since been increased to an average of 18 to 20 loadings per month, equivalent to over 400 kb/d on an annual basis, and the expectation is that this will rapidly increase to the full capacity of the pipeline as companies such as GazpromNeft and Surgutneftegas, as well as Rosneft, seek to increase their eastern sales.

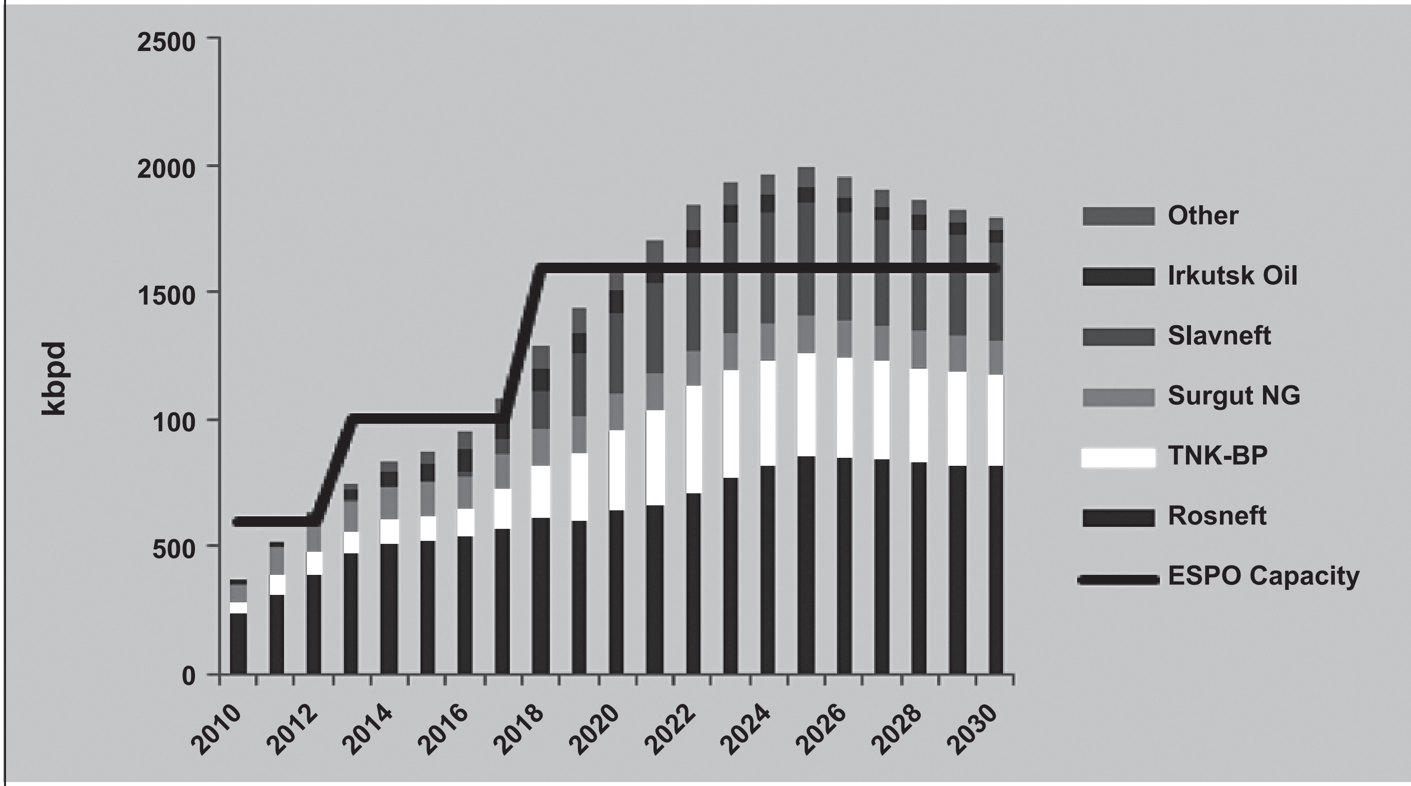
Furthermore, the pace of Russia's shift east accelerated in October 2013, following a series of new agreements reached by Rosneft and its Chinese state-owned counterparts. Firstly, Rosneft agreed an $85bn deal to supply 10 mmtpa for 10 years in a partly pre-financed arrangement with Sinopec, with first deliveries commencing in 2014. Secondly, Rosneft confirmed its involvement in the Tianjin refinery near Beijing with CNPC, with a commitment that Russia would provide 9 mmtpa to the plant once it has been completed (in 2019/2020). As a result, taking into account just the existing agreements in place, Russian oil exports to China are expected to increase to around 35 mmtpa by the end of this decade, and indeed the Energy Ministry claims that exports will reach 30 mmtpa as soon as 2014, with half moving through the existing spur pipeline and half coming by sea from Kozmino Bay. As a result of this trend, and increasing demand for Russian crude from other north-east Asian consumers, plans for development of the third stage of the ESPO pipeline are already under active discussion. This would see the total capacity of the system increased to 80 mmtpa (1.6 mb/d), with the spur to China increased to a capacity of 30 mmtpa and the line to Kozmino Bay reaching 50 mmtpa, with the expansion confirming Russia's recently announced plan that one third of its oil exports should be sold into Asia by 2020. Indeed Transneft CEO Nikolay Tokarev and the Russian Energy Ministry are now actively considering the possibility that the ESPO may need to be expanded further beyond 2020, with a plan that oil exports to Asia should reach almost 2 mb/d by 2030.

The Possibility of ESPO Becoming an Oil Benchmark

In the light of this planned growth in eastern oil exports, the question of ESPO crude becoming a benchmark in Asia is one that has been hotly debated in Russia, and the government is clearly keen to find a way to demonstrate its growing influence in the region's energy market. This goal has been encouraged by the fact that the credibility of some of the existing benchmarks in Asia appears to have weakened, with the main Dubai benchmark actually only trading a very small number of lots during the year. However, despite this lack of specific liquidity, oil companies appear reluctant to abandon a historic trading mechanism, while the development of highly liquid swaps markets, which have allowed traders to convert Dubai price risk into Brent price risk, has increased the effective liquidity of the Dubai benchmark and allowed it to remain the main price market for Middle Eastern crudes around the world. Furthermore, the introduction of a new DME Oman crude oil futures contract on the Dubai Mercantile Exchange in 2007 has introduced another benchmarking option for Asian buyers, and trading volumes have doubled since 2010 to 6.5 mb/d, according to the agency Risk.net in an article on 15 April 2013. With more than 60 market participants already using the contract to provide a reference to the price for crude produced in the major exporting region to Asia, it is clear that buyers will not give up a Middle East benchmark easily. As a result, ESPO crude would have to pass a number of crucial tests if it is to have any hope of usurping the position of Dubai or DME Oman as key benchmarks in Asia, given that, according to the *BP Statistical Review of World Energy 2012*, more than half of the region's imports still come from the Middle East.

The first key question is whether there is adequate crude supply to maintain throughput through the ESPO at full capacity. The answer at present would appear to be a reserved yes, although Russian companies will need to establish a long-term development and production plan for new and existing fields if consumers are ultimately to be convinced that an ESPO benchmark is sustainable. The construction of the pipeline has already provided development incentives, with three major fields, Vankor, Verkhnechonsk, and Talakan, supplemented by a number of smaller fields, providing the initial foundation for Russia's eastern production. Two other large fields, Yurubcheno–Tokhomskoye and Kuyumba, are set to be linked to the ESPO by 2016, and a number of other discoveries have been made by Rosneft close to its existing assets in the region. As a result, production of 1 mb/d from East Siberia alone is possible within the next five years. Added to this will be fields in West Siberia that have now been linked to the ESPO via a new pipeline connection from the Yamal region, and as a result it is possible to create a production profile that can fill the fully expanded three-phase ESPO with 1.6 mb/d of output by 2020 (Figure 1). When one also considers that East Siberia has 10 billion barrels of identified reserves and at least as much again of potential resources, then the opportunity to increase production is obvious. However, what is also clear is that both the Russian government, via a stable tax regime providing appropriate tax

Figure 1: Potential Russian production that could be exported through the ESPO.



(source: author's estimates based on company data and Wood Mackenzie Consultants CAT database)

incentives, and Russian oil companies, via a commitment to invest, must demonstrate that this potential can become a reality before ESPO crude can hope to become a benchmark.

'Another fundamental issue that will need to be addressed will be confirmation of the long-term quality of the ESPO blend.'

However, it is not just a question of oil being available to flow through the ESPO, but also of its ability to create a liquid market in Asia upon which contracts can be reliably based and derivatives markets be established. According to Jorge Montepeque, the global director of market reporting at Platts, reported in a *Wall Street Journal* article of 28 October 2012, it is generally accepted that for any crude to establish itself as a benchmark, it should have at least 500 kb/d of output, and in the case of ESPO this should really mean output available for trading at Kozmino Bay. As discussed above, of the 1.6 mb/d capacity that could be available from ESPO, at least 600 kbpd will be sent to China via a direct spur that provides no market liquidity. In addition, another market for ESPO crude is domestic – to support the development of infrastructure and industry in the Far East of Russia, a key government priority. As a result, ESPO crude is expected to be delivered to two refineries, at Komsomolsk and Khabarovsk, and also to a petrochemicals plant that Rosneft is planning to build near Vladivostok. The combined capacity of these three plants is approximately 500 kbpd. As Figure 2 shows, if they do all reach full utilization, then the amount of crude traded at Kozmino Bay would be very close to the notional 500 kbpd limit for benchmark status. Any further expansion in Russia's eastern downstream capacity after 2020 would clearly undermine any ESPO benchmark, unless the pipeline system is expanded further.

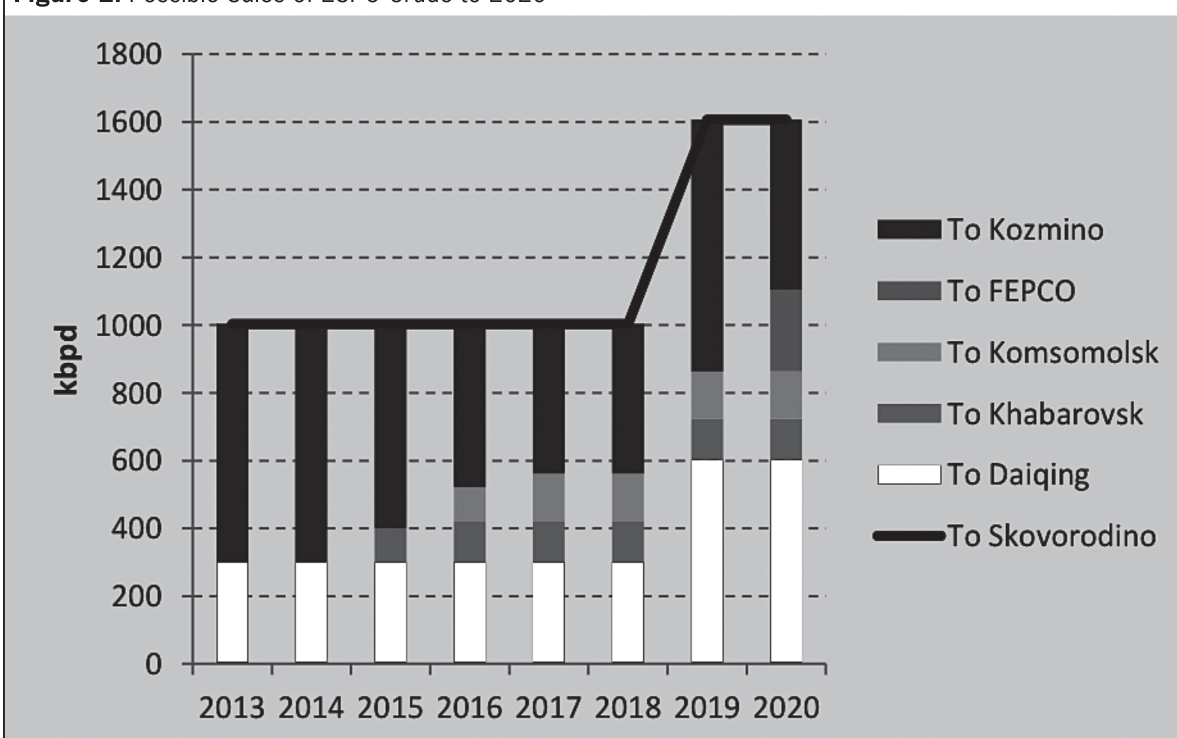
Another fundamental issue that will need to be addressed will be confirmation of the long-term quality of the ESPO blend. At present, this would not appear to be an issue as it has been defined as having a sulphur content of 0.61 per cent and a density of 0.843 kg/cubic metre; the proof of the high quality of the blend and its relative stability can be seen in the increasing premium at which it has traded to the Dubai marker in Asia, which has risen from $1.25/bbl in 2010 to an average of $4–5/bbl in 2013. However, despite this apparent success, two main risks remain for the ESPO crude blend. The first is that crude quality in western Russia appears to be in decline, and Transneft may be forced to make some adjustments that could see more sour crude moved east in order to reduce the sulphur content in west-facing exports. Although the company is keen to reassure its customers that this will not mean that ESPO crude will exceed its maximum parameters, the risk of deterioration is clear, as highlighted in an *Interfax* article of 15 October 2012. An additional risk is that the introduction of new field production could also change the quality of ESPO crude. As mentioned above, new fields in East and West Siberia are expected to contribute new oil supply from 2016, but once again (according to another *Interfax* article of 15 October 2012) Transneft has moved to assure its Asian customers that quality will not be impaired.

In terms of creating the liquidity required of a crude benchmark, the question of diversity of buyers and sellers also needs to be considered. From a buyer's perspective, a broad market for ESPO crude has already been established in Asia, with consumers in Japan, Korea, the USA, and China taking similar shares of Russia's eastern exports. However, this split could be undermined if China continues to supplement its piped imports of ESPO crude with additional purchases from Kozmino Bay. The diversity of sellers of ESPO crude is linked to another crucial issue, namely political risk, as the state-owned company Rosneft is becoming increasingly dominant in terms of Russia's eastern expansion. GazpromNeft, Surgutneftegas, and TNK-BP were initially the other key players, but TNK-BP has now been acquired by Rosneft, which means that the Russian state now controls all piped sales to China and around one third of exports from Kozmino Bay. With a state-owned company also controlling the pipeline artery to the Pacific coast, the risk to consumers of a change in Russian government policy towards exports in general, or to specific markets, is clear. Despite that fact that the Russian authorities are unlikely to undermine a significant source of budget revenues by disrupting exports for any length of time, the uncertainty of political relations with both China and Japan could provide a continuing source of concern.

'In terms of creating the liquidity required of a crude benchmark, the question of diversity of buyers and sellers also needs to be considered.'

Finally, and perhaps equally importantly, is the need for any crude that has aspirations of benchmark status to offer hedging opportunities to buyers and sellers on a futures exchange, (see Bassam Fattouh's OIES paper 'The Dubai Benchmark and its Role in the International Oil Pricing System'). To date, Russian crude oil has not been traded on an exchange basis, and the only futures trading has been in a very limited market on SPIMEX in St Petersburg, where one type of future for summer diesel has been offered since 2010 (see *Interfax*, 16 July 2012). However, interest in creating a broader marker for both oil and oil product trading has emerged in 2013, with the Russian Energy Ministry currently working on a road map for trading to commence in 2014, probably based on the St Petersburg SPIMEX exchange which actually tried to implement this independently in 2011, and managed one trade in ESPO crude. However, much more assertive action will clearly need to be taken if the ESPO blend is to offer a financial as well as a physical market, and indeed the Head of SPIMEX has forecast (see *Interfax* 19 December 2012) that it would be five years before the development of exchange trading could allow ESPO to become a benchmark crude. This forecast would seem to be realistic given the challenges facing the establishment of a solid production base in East Siberia, a continued diversity of buyers and sellers, a secure quality assessment and, most critically, an improved perception of Russian political risk.

Figure 2: Possible Sales of ESPO Crude to 2020



(source: author's estimates)

The Price Debate: do free markets provide the right signals?

JORGE MONTEPEQUE

The 2008 oil price spike, which was accompanied by similar sharp price rises in coal, iron ore, food, and many other commodities, sparked a debate which still resonates five years later. Countless articles, commentaries, conferences, and much learned debate has occurred over whether the market was working well and providing the 'right' price signals or whether it was dysfunctional or, worse yet, wilfully distorted. All these analyses seem to have been asking whether (a) the price rise was driven by fundamentals, (b) what factors were behind the price spike, and (c) what could be done about it. In some cases, it seems, solutions were devised before the nature of the problem was fully determined.

The Issue

Prices for Dated Brent, the bellwether for crude oils, reached a peak of over \$145/bbl in June 2008, before tumbling all the way down to nearly \$35/bbl later in the same year as markets corrected lower. The high prices and subsequent volatility shocked consumers, producers, and government entities alike. But such price movements are all a reminder that markets work by delivering messages that affected parties may not want to hear. They are not the sign of a dysfunctional market. Price is the allocator of supply and demand, providing the signals to invest in the production of new supply or conservation of resources to reduce demand. Above all, price modifies behaviour.

However, some of the signals carried in the price are painful to both producers and consumers. It is therefore understandable that many look for solutions to dampen volatility and even try to find a 'price' that is simultaneously comfortable for buyers and sellers. But this search for a compromise price leads to anomalies: if measures that distort the free market price signal are put in place, then needed investment or adaptation of behaviour by consumers and producers will not occur.

Experiments to manage price are as old as history. There are even examples of price controls from Roman times, designed to tackle inflation caused by budget deficits. More recently, there have been numerous examples of countries faced with runaway budgets that stem from attempts to shield the final consumers from retain price changes. One example is that experienced by the USA in the 1970s as it tried to control the price of gasoline and other products.

'Price is the allocator of supply and demand, providing the signals to invest in the production of new supply or conservation of resources to reduce demand.'

The 2008 crude oil price spike to nearly \$150/bbl rattled many market participants, including retail consumers, airlines, and even professional traders, who had thought that the likelihood of prices rising above \$100/bbl was remote. In retrospect, it has become clear that the key driver was that demand for oil was growing at a faster pace than supply. China and other emerging economies were enjoying rapid growth fuelled by a low interest rate policy driven by the US Federal Reserve. And economic growth needs energy, and lots of it. Chinese oil demand jumped from 4.8 mb/d in 2000 to 7.5 mb/d by 2007, a rise of over 50 per cent, according to the US Energy Information Administration.

Prices were the arbiter determining who was to have access to energy. Dated Brent prices in 2000 stood at nearly \$30/bbl but had jumped to nearly \$75/bbl by 2007, reflecting the pressure of growing demand. The fact that prices should double when demand had not risen by a similar quantum is far from unusual: in any market with low spare capacity, a relatively small change in demand can trigger a disproportionate change in price to ensure that production plus changes in inventories equals demand. *Caution: the opposite is also true.*

While the reasons for the price rise appear obvious in retrospect, the debate about the 2008 price spike continues. Most recently, a pricing expert at the World Petroleum Congress conference in Korea opined that markets were dysfunctional in 2008, and cast doubt on the validity of the \$147/bbl Brent price. But it is worth noting that similar, if not higher, prices were observed simultaneously in the USA, Canada, Africa, Europe, the Middle East, and Asia. The high price was global and was detected independently by publishers, exchanges, and the public.

The price reversal in late 2008 turned into a stampede with a thinner herd galloping the other way. Prior to this period, energy had been considered to have a low price elasticity. The theory was that consumers would not react to high prices and were price insensitive. Instead, US gasoline demand peaked in the summer of 2007 at 9.6 mb/d following a history of nearly ruler straight line year-on-year increases. Consumers literally voted with their feet and a process began where medium- to small-sized vehicles started to see their market share grow. Again, a relatively small change in demand had a disproportionately large impact on prices.

The crude oil price retreat that followed the all-time highs was fast and furious. Prices started to fall in early July 2008, and by the end of the year had dropped to \$35/bbl. A rapid output cut by OPEC, monetary easing, and political events which included the 'Arab Spring' and other instability in the Middle East, subsequently moved prices back above the \$100/bbl line with occasional jumps towards \$120/bbl.

The Disconnect

At this stage, however, a disconnect emerges between the data showing what drove the price up (and down) in the new millennium, and the various measures debated to 'address' the price issue. Concerns continue over transparency in oil markets, despite the fact that oil is the most tracked commodity in the world, with service providers delivering information covering production, inventories, ship movements, the opening and closing of arbitrages, and most importantly trade data covering who bought and who sold and exactly at what prices.

Countless hours have been spent trying to find a more interesting result to investigations than just mere supply and demand forces at play. The lack of any hard data suggesting evidence of the malfunctioning of markets has not stopped well-intentioned proposals and measures from being issued to address potentialities and probabilities.

Meanwhile, the market continues to work.

High prices are not only supposed to modify buyers' behaviour. Prices also influence sellers' behaviour, investment, exploration, and production plans. Coinciding with the oil price spike, a new round of investments, financed by the high prices, took over in the USA with the advent of technology that enabled the exploitation of shale reserves.

'Prices were the arbiter determining who was to have access to energy.'

US production has increased by over 50 per cent since 2008 to nearly 8.0 mb/d, the highest in over 25 years, while oil imports have hit an 18 year low. It is fairly easy to conclude that the sharp increase in production is a direct function of the recent high prices. Figure 3 below shows the remarkable American experience, where output so far in 2013 has risen by 17 per cent versus last year. And on a total liquids production, the USA has become the largest producer globally as it is churning out roughly 7.8 mb/d of crude plus nearly 2.5 mb/d in natural gas liquids and over 800 kb/d of biofuels. The total places the USA above Russia, the second largest producer.

Other geographical areas have not benefited as much as the USA from the afterglow of the price boom as either they do not have the resources or the infrastructure, while they may have high taxation regimes that discourage investment or have policies against shale development.

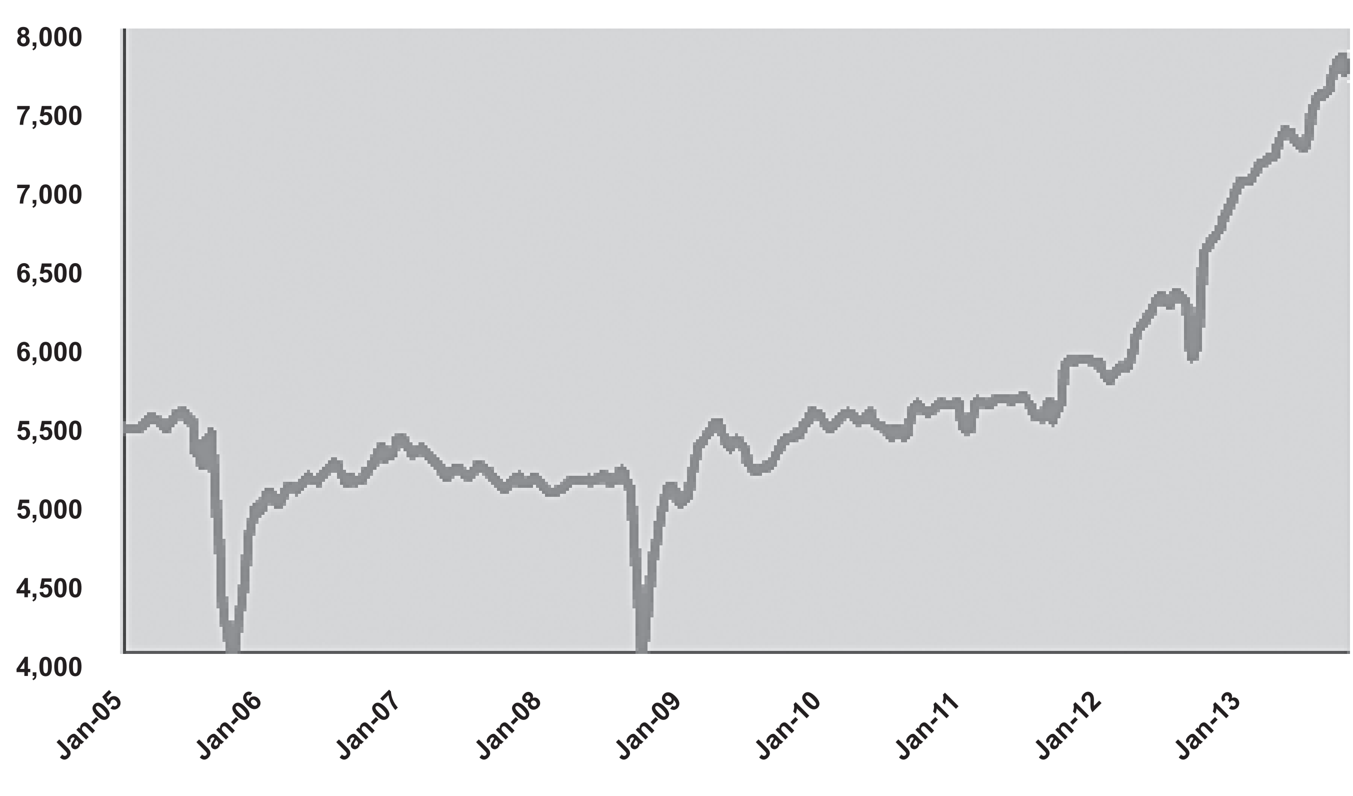
The 'Solutions'

While classical economists would look to address prices on measures that would change demand or supply, efforts on the 'soft' side of pricing continue. There are various initiatives to improve transparency and/or implement new procedural or data recording measures.

One area of concern in the overall industry is the potential for unintended consequences in the fabric of pricing processes, more so because the energy industry is undergoing major fundamental changes.

There are many inflection points or sharp changes in direction that are taking place currently. These include such key developments as the change

Figure 3: US production of crude oil, mb/d.



(source: EIA)

from the USA being the largest waterborne importer of crude oil to the second largest, ceding the top spot to China. There is also a continuous decline in North Sea production, which has been depleting at the rate of about 7 per cent per annum amid signs that the major building of refineries in Asia and Middle East will point to possible large refinery shutdowns of close to 2.0 mb/d in the next five years or so in Europe if the current economic conditions do not pick up. Europe's role could dim due to a combination of oil fundamentals both reducing crude oil output and demand, and an environment filling up with regulatory exposures. These changes point to a need for greater Middle East–Asian crude pricing prominence at the expense of the West, with a likely growing reliance on the Dubai benchmark, although some expect Europe to become more business-friendly if the slowdown or production decline is too steep. As an emerging sign, the UK is undergoing a deep review of investment in the country and looking at what needs to be changed to arrest the production decline.

Nevertheless, several Middle East and Asian participants ponder their reliance on Western systems as the structural weight of demand moves east. Early warning signs have already emerged, as there is some evidence of balkanization in Western markets as non-US domiciled entities are only wanting to trade with similarly incorporated entities to avoid Dodd–Frank or any other transnational issues.

'… the core market concern is liquidity …'

But the core market concern is liquidity. There are fears that growing requirements from the trade will naturally raise costs and cause an exit or re-routing to less onerous areas. Some have noticed the declining liquidity in natural gas market futures as evidence of a retreat. Liquidity is also declining in the derivative markets, with some noticing a loss of market depth as participants encounter fewer choices when needing to trade.

Platts tracking of derivatives versus physical markets show a change in composition between 2012 and 2013. The share of derivatives instruments shrank from 55 per cent to 51 per cent on a year-to-year basis.

Regardless of whether energy markets are providing unbiased price signals, very few would disagree that a free market price undoubtedly provides the correct triggers to influence demand and supply. And this price message should not be tampered with or guided, even if the message is not welcomed. After all, if there is a concern over high prices, one should not forget the maxim 'there is nothing like high price to cure high prices', as we saw in the downward correction in US natural gas prices and the emerging behaviour in the US crude oil market. High prices brought about innovation and supply in those countries open to energy development, and if prices were to fall by natural causes, such a decline would rightly encourage the seeds of increased consumption, bringing about another upward cycle. ■

Reply to *OEF93*

MICHAEL HOCHBERG

The preliminary excitement surrounding Israel's natural gas discoveries – most notably the Leviathan Field – has translated into broad speculation as policy experts surmise potential paths for Israeli natural gas development and exportation. In issue 93 of the *Forum*, Paritzky and Farren-Price, Elston and Stewart, and Bryza assess Israel's potential export options, considering the political realities and geographical limitations which make a sound and feasible path to exportation particularly tricky.

While analysis of the tentative logistics of Israel's future natural gas exportation is essential, it is equally important to discuss the perils of the resource curse theory for Israel, as it develops its natural gas. The above-mentioned authors discuss the challenges Israel faces in its journey to natural gas exportation, yet never explicitly mention the vulnerabilities now facing the country as a result of its natural resources. As Israel confronts the logistical challenges of exportation, it must remain mindful of the potentially disastrous unintended consequences of resource discoveries.

'It is critical for Israel to take a holistic view of resource management.'

In its export considerations, Israel should be wary of the Dutch Disease. The mere indication of a future Israeli natural gas bonanza has facilitated the new Israeli shekel to appreciate by 3 per cent in 2013 alone. As exports in 2012 comprised over 26 per cent of the Israeli economy, Israel must implement measures to maintain the competitiveness of its non-resource exports in the global marketplace.

To this end, Israel has passed legislation to establish a sovereign wealth fund where its resource windfalls will be managed. Through the fund Israel will undertake various investments – such as currency diversification schemes – which should help curb rapid appreciation of the new Israeli shekel. The Israeli government, however, would be wise to study the accounts of resource-rich nations as a means of understanding and ultimately avoiding the Dutch Disease.

In the coming decades, Israel's resource profits are estimated to be hundreds of billions of dollars. Despite its strong democratic institutions, Israel must be mindful of rent seeking, given its projected windfall gains and culture of collusion among businessmen and politicians. According to some accounts Israel is one of the most corrupt OECD countries. The nation should therefore create a system of checks and balances which crafts a healthy distance between politicians and natural gas dividends, and seek guidance from countries which have already succeeded in doing so, such as Norway. When the Bank of Norway was awarded increased autonomy and political independence by law, the management of Norway's resource profits was transferred from the Ministry of Finance to the central bank. Israel should institute similar measures to ensure that corruption does not subvert the nation's natural resource sector.

Investing wisely at home is another pivotal aspect of sound natural resource management. The Israeli cabinet has announced that much of the money generated from the Leviathan Field will go toward civic projects such as education, security, infrastructure, and healthcare. In addition to boosting human capital, social service ventures will demonstrate to average Israeli citizens that a share of the resource rents is intended for their direct benefit.

'As Israel confronts the logistical challenges of exportation, it must remain mindful of the potentially disastrous unintended consequences of resource discoveries.'

A portion of the nation's resource rents should also be invested in technology, capital goods, and human capital associated with its own energy industry. Such investments would foster an understanding of the technical operations occurring within its own borders, allowing Israel to develop and maintain greater control of its resource management. If successful in fostering these valuable knowledge externalities, Israel could conceivably develop a cluster related to its natural gas sector and revolutionize its business environment. Israel should study the role of cluster initiatives in stimulating economic growth and examine the experience of, for example, Brazil, Norway, and the United Kingdom.

It is critical for Israel to take a holistic view of resource management. As the authors of August's *Forum* correctly argue, Israel has a number of logistical options to consider in determining trade partners and methods of resource development. Yet it is equally important that all anticipated and unforeseen externalities of its resource boom are properly managed. Deals will be reached, logistics will be settled, and Israel will export its natural gas. Multinational energy corporations and regional trade partners are sure to profit from Israel's bounties. If the tiny Mediterranean nation seeks to maximize what is perhaps its greatest gift fully, it must adopt a comprehensive perspective and earnestly consider the potential consequences of the resource curse. ■

Asinus Muses

The curious comeback of King coal

Coal, having quietly kept its head down for some time, has returned coughing and dusty to the limelight, shoved on-stage by one of its most intensive users, Poland. The country, 90 per cent of whose electricity is generated by coal, played host to the World Coal Association's International Coal & Climate Summit, trailed as bringing together the great and the good 'to discuss the role of coal in the global economy, in the context of the climate change agenda'. They meant 'in the context' rather literally: the summit took place during the 19th Conference of the UN Framework Convention on Climate Change, also hosted by Warsaw. Both events come on the heels of the Intergovernmental Panel on Climate Change's announcement that humanity has consumed more than half of its 'carbon budget' of 1,000 gigatons, the maximum we may emit if we are to avoid global warming above 2 degrees. Asinus suggests that the WCA's meeting is not just 'in the context of' but rather 'up in the face of' the climate change agenda.

Extracting the carbon and taking the Mickey Bliss

Poland, adding insult to insult, supported the WCA's call for 'the immediate use of high-efficiency low-emissions coal combustion technologies, wherever it is economic and technically feasible'. Inspired by their insertion of that useful qualifier, Asinus will affirm that he will live a life of poverty and charity 'wherever it is economic'.

Dances with huskies

Yet Poland is simply taking ownership of a more widespread phenomenon: the International Energy Agency estimates that coal is still likely to be the leading electricity-generating fuel in 2035. In Britain, indeed, coal accounts for about 40 per cent of electricity generation. We in Blighty, however, are taking heroic measures to cut carbon. At least, that's what Tory voters were assured in 2006 when now-Prime Minister David Cameron travelled to the Arctic to frolic with the huskies, demonstrating his environmentalist bona fides. But it appears his sled has just made an abrupt U-turn – or it might be a veer to the right. Riled by Labour leader Ed Miliband's promise to freeze energy prices for 20 months if he takes power in 2015, Mr Cameron has decided that the solution to rising household energy bills is to cut green taxes. Downing Street has conspicuously failed to deny reports that Cameron told aides to 'get rid of all the green crap' in energy legislation: the prime minister, apparently, merely 'did not recognize' the quote. This is hardly convincing as a rebuttal. Asinus has observed that our prime minister sometimes fails to recognize his posterior from his elbow, but that does not mean the fellow is not responsible for them.

License to drill

Asinus has recently reported on Mexico's newish government of the Institutional Revolutionary Party (PRI), which swept back into power on the promise of major reform throughout the economy and society. It is finally the turn of the long-trailed oil reform to make its way through the wringer of Mexican politics. The government's first proposal, to allow production sharing agreements, received a cool reaction from industry participants. Under pressure from the 'centre right' opposition party, the PAN, they are now moving towards a concessions regime. But in order to avoid unwanted connotations it has been decided that they shall be known by the label 'licences'. Regular readers will know that Asinus is no cheerleader for the business practices of IOCs. Yet the public's specific dislike of the idea of losing 'ownership' of the oil is as irrational as IOCs' need to gain 'ownership,' or to 'book reserves', in order to satisfy Wall Street. Why either party thinks ownership of hydrocarbons is more important than rights to the revenue they produce has always been a mystery. As put by Asinus's glorious leader Mr Allsopp, director of the Oxford Institute for Energy Studies, Wall Street doesn't value Walmart on the value of its warehoused inventory. But then, our original glorious leader Mr Mabro's opinion of Wall Street's oil analysts is not suitable for printing in a family publication such as the *Oxford Energy Forum*.

Heart-warming news

New research has found that 90 companies produced nearly two-thirds of greenhouse gas emissions since the beginning of the industrial age. The report was produced by the Climate Accountability Institute in Colorado, whose title reveals the purpose of the research: who can we blame for global warming? How reassuring to have found the culprits, at last. Naturally the companies include IOCs such as Exxon, Shell, and BP, members of the aforementioned World Coal Association such as Peabody Energy and BHP Billiton, and NOCs such as Saudi Aramco, Gazprom, and Statoil. Asinus feels much relieved of his burden of carbon guilt. On his forthcoming transatlantic flight he will take time to reflect on the wrongdoings of the company who produced the fuel powering the aeroplane.

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