An Anatomy of the Crude Oil Pricing System

Bassam Fattouh[1]

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[1] Bassam Fattouh is the Director of the Oil and Middle East Programme at the Oxford Institute for Energy Studies; Research Fellow at St Antony's College, Oxford University; and Professor of Finance and Management at the School of Oriental and African Studies, University of London. I would like to express my gratitude to Argus for supplying me with much of the data that underlie this research. I would also like to thank Platts for providing me with the data for Figure 21 and CME Group for providing me with the data for Figure 13. The paper has benefited greatly from the helpful comments of Robert Mabro and Christopher Allsopp and many commentators who preferred to remain anonymous but whose comments provided a major source of information for this study. The paper also benefited from the comments received in seminars at the Department of Energy and Climate Change, UK, ENI, Milan and Oxford Institute for Energy Studies, Oxford. Finally, I would like to thank those individuals who have given their time for face-to-face and/or phone interviews and have been willing to share their views and expertise. Any remaining errors are my own.

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Summary Report

The view that crude oil has acquired the characteristics of financial assets such as stocks or bonds has gained wide acceptance among many observers. However, the nature of 'financialisation' and its implications are not yet clear. Discussions and analyses of 'financialisation' of oil markets have partly been subsumed within analyses of the relation between finance and commodity indices which include crude oil. The elements that have attracted most attention have been *outcomes*: correlations between levels, returns, and volatility of commodity and financial indices. However, a full understanding of the degree of interaction between oil and finance requires, in addition, an analysis of interactions, causations and processes such as the investment and trading strategies of distinct types of financial participants; the financing mechanisms and the degree of leverage supporting those strategies; the structure of oil derivatives markets; and most importantly the mechanisms that link the financial and physical layers of the oil market.

Unlike a pure financial asset, the crude oil market also has a 'physical' dimension that should anchor prices in oil market fundamentals: crude oil is consumed, stored and widely traded with millions of barrels being bought and sold every day at prices agreed by transacting parties. Thus, in principle, prices in the futures market through the process of arbitrage should eventually converge to the so-called 'spot' prices in the physical markets. The argument then goes that since physical trades are transacted at spot prices, these prices should reflect existing supply-demand conditions.

In the oil market, however, the story is more complex. The 'current' market fundamentals are never known with certainty. The flow of data about oil market fundamentals is not instantaneous and is often subject to major revisions which make the most recent available data highly unreliable. Furthermore, though many oil prices are observed on screens and reported through a variety of channels, it is important to explain what these different prices refer to. Thus, although the futures price often converges to a 'spot' price, one should aim to analyse the process of convergence and understand what the 'spot' price in the context of the oil market really means.

Unfortunately, little attention has been devoted to such issues and the processes of price discovery in oil markets and the drivers of oil prices in the short-run remain under-researched. While this topic is linked to the current debate on the role of speculation versus fundamentals in the determination of the oil price, it goes beyond the existing debates which have recently dominated policy agendas. This report offers a fresh and deeper perspective on the current debate by identifying the various layers relevant to the price formation process and by examining and analysing the links between the financial and physical layers in the oil market, which lie at the heart of the current international oil pricing system.

The adoption of the market-related pricing system by many oil exporters in 1986-1988 opened a new chapter in the history of oil price formation. It represented a shift from a system in which prices were first administered by the large multinational oil companies in the 1950s and 1960s and then by OPEC for the period 1973-1988 to a system in which prices are set by 'markets'. First adopted by the Mexican national oil company PEMEX in 1986, the market-related pricing system received wide acceptance among most oil-exporting countries. By 1988, it became and still is the main method for pricing crude oil in international trade after a short experimentation with a products-related pricing system in the shape of the netback pricing regime in the period 1986-1987. The oil market was ready for such a transition. The end of the concession system and the waves of nationalisation which disrupted oil supplies to multinational oil companies established the basis of arm's-length deals and exchange outside the vertically and horizontally integrated multinational companies. The emergence of many suppliers outside OPEC and many buyers further increased the prevalence of such arm's-length deals. This led to the development of a complex structure of interlinked oil markets which consist of spot and also physical forwards, futures, options and other derivative markets referred to as paper markets. Technological innovations which made electronic trading possible revolutionised these markets by allowing 24-hour trading from any place in the world. It also opened access to a wider set of market participants and allowed the development of a large number of trading instruments both on regulated exchanges and over the counter.

Physical delivery of crude oil is organised either through the spot (cash) market or through long-term contracts. The spot market is used by transacting parties to buy and sell crude oil not covered by long term contractual arrangements and applies often to one-off transactions. Given the logistics of transporting oil, spot cargoes for immediate delivery are rare. Instead, there is an important element of forwardness in spot transactions. The parties can either agree on the price at the time of agreement, in which case the sport transaction becomes closer to a 'forward' contract. More often though, transacting parties link the pricing of an oil cargo to the time of loading.

Long-term contracts are negotiated bilaterally between buyers and sellers for the delivery of a series of oil shipments over a specified period of time, usually one or two years. They specify among other things, the volumes of crude oil to be delivered, the delivery schedule, the actions to be taken in case of default, and above all the method that should be used in calculating the price of an oil shipment. Price agreements are usually concluded on the method of formula pricing which links the price of a cargo in long-term contracts to a market (spot) price. Formula pricing has become the basis of the oil pricing system.

Formula pricing has two main advantages. Crude oil is not a homogenous commodity. There are various types of internationally traded crude oil with different qualities and characteristics which have a bearing on refining yields. Thus, different crudes fetch different prices. Given the large variety of crude oils, the price of a particular type is usually set at a discount or at a premium to marker or reference prices, often referred to as benchmarks. The differentials are adjusted periodically to reflect differences in the quality of crudes as well as the relative demand and supply of the various types of crudes. Another advantage of formula pricing is that it increases pricing flexibility. When there is a lag between the date at which a cargo is bought and the date of arrival at its destination, there is a price risk. Transacting parties usually share this risk through the pricing formula. Agreements are often made for the date of pricing to occur around the delivery date.

At the heart of formulae pricing is the identification of the price of key 'physical' benchmarks, such as West Texas Intermediate (WTI), Dated Brent and Dubai-Oman. The benchmark crudes are a central feature of the oil pricing system and are used by oil companies and traders to price cargoes under long-term contracts or in spot market transactions; by futures exchanges for the settlement of their financial contracts; by banks and companies for the settlement of derivative instruments such as swap contracts; and by governments for taxation purposes.

Few features of these physical benchmarks stand out. Markets with relatively low volumes of production such as WTI, Brent, and Dubai set the price for markets with higher volumes of production elsewhere in the world. Despite the high level of volumes of production in the Gulf, these markets remain illiquid: there is limited spot trading in these markets, no forwards or swaps (apart from Dubai), and no liquid futures market since crude export contracts include destination and resale restrictions which limit trading options. While the volume of production is not a sufficient condition for the emergence of a benchmark, it is a necessary condition for a benchmark's success. As markets become thinner and thinner, the price discovery process becomes more difficult. Oil price reporting agencies cannot observe enough genuine arms-length deals. Furthermore, in thin markets, the danger of squeezes and distortions increases and as a result prices could then become less informative and more volatile thereby distorting consumption and production decisions. So far the low and continuous decline in the physical base of existing benchmarks has been counteracted by including additional crude streams in an assessed benchmark. This had the effect of reducing the chance of squeezes as these alternative crudes could be used for delivery against the contract. Although such short-term solutions have been successful in alleviating the problem of squeezes, observers should not be distracted from some key questions: What are the conditions necessary for the emergence of successful benchmarks in the most physically liquid market? Would a shift to assessing price in these markets improve the price discovery process? Such key questions remain heavily under-researched in the energy literature and do not feature in the consumer-producer dialogue.

The emergence of the non-OECD as the main source of growth in global oil demand will only increase the importance of such questions. One of the most important shifts in oil market dynamics in recent years has been the shift in oil trade flows to Asia: this may have long-term implications on pricing benchmarks. Questions are already being raised whether Dubai still constitutes an appropriate benchmark for pricing crude oil exports to Asia given its thin physical base or whether new benchmarks are needed to reflect more accurately the recent shift in trade flows and the rise in prominence of the Asian consumer.

Unlike the futures market where prices are observable in real time, the reported prices of physical benchmarks are 'identified' or 'assessed' prices. Assessments are needed in opaque markets such as crude oil where physical transactions concluded between parties cannot be directly observed by outsiders. Assessments are also needed in illiquid markets where there are not enough representative deals or where no transactions are concluded. These assessments are carried out by oil pricing reporting agencies (PRAs), the two most important of which are Platts and Argus. While PRAs have been an integral part of the oil pricing system, especially since the shift to the market-related pricing system in 1986, their role has recently been attracting considerable attention. In the G20 summit in Korea in November 2010, the G20 leaders called for a more detailed analysis on 'how the oil spot market prices are assessed by oil price reporting agencies and how this affects the transparency and functioning of oil markets'. In its latest report in November 2010, IOSCO points that 'the core concern with respect to price reporting agencies is the extent to which the reported data accurately reflects the cash market in question'. PRAs do not only act as 'a mirror to the trade'. In their attempt to identify the price that reflects accurately the market value of an oil barrel, PRAs enter into the decision-making territory which can influence market structure. What they choose to do is influenced by market participants and market structure while they in turn influence the trading strategies of the various participants. New markets and contracts may emerge to hedge the risks arising from some PRAs' decisions. To evaluate the role of PRAs in the oil market, it is important to look at three inter-related dimensions: the methodology used in indentifying the oil price; the accuracy of price assessments; and the internal measures that PRAs implement to protect the integrity and ensure an efficient assessment process. There is a fundamental difference in the methodology and in the philosophy underlying the price assessment process between the various PRAs. As a result, different agencies may produce different prices for the same benchmark. This raises the issue of which method produces a more accurate price assessment. Given that assessed prices underlie long-term contracts, spot transactions and derivatives instruments, even small differences in price assessments between PRAs have important implications on exporters' revenues and financial flows between parties in financial contracts.

In the last two decades or so, many financial layers (paper markets) have emerged around crude oil benchmarks. They include the forward market (in Brent and Dubai), swaps, futures, and options. Some of the instruments such as futures and options are traded on regulated exchanges such as ICE and CME Group, while other instruments, such as swaps, options and forward contracts, are traded bilaterally over the counter (OTC). Nevertheless, these financial layers are highly interlinked through the process of arbitrage and the development of instruments that links the various layers together. Over the years, these markets have grown in terms of size, liquidity, sophistication and have attracted a diverse set of players both physical and financial. These markets have become central for market participants wishing to hedge their risk and to bet on oil price movements. Equally important, these financial layers have become central to the oil price identification process.

At the early stages of the current pricing system, linking prices to benchmarks in formulae pricing provided producers and consumers with a sense of comfort that the price is grounded in the physical dimension of the market. This implicitly assumes that the process of identifying the price of benchmarks can be isolated from financial layers. However, this is far from reality. The analysis in this report shows that the different layers of the oil market form a complex web of links, all of which play a role in the price discovery process. The information derived from financial layers is essential for identifying the price level of the benchmark. In the Brent market, the oil price in the forward market is sometimes priced as a differential to the price of the Brent futures contract using the Exchange for Physicals (EFP) market. The price of Dated Brent or North Sea Dated in turn is priced as a differential to the forward market through the market of Contract for Differences (CFDs), another swaps market. Given the limited number of physical transactions and hence the limited amount of deals that can be observed by oil reporting agencies, the value of Dubai, the main benchmark used for pricing crude oil exports to East Asia, is often assessed by using the value of differentials in the very liquid OTC Dubai/Brent swaps market. Thus, one could argue that without these financial layers it would not be possible to 'discover' or 'identify' oil prices in the current oil pricing system. In effect, crude oil prices are jointly or co-determined in both layers, depending on differences in timing, location and quality of crude oil.

Since physical benchmarks constitute the pricing basis of the large majority of physical transactions, some observers claim that derivatives instruments such as futures, forwards, options and swaps derive their value from the price of these physical benchmarks, i.e., the prices of these physical benchmarks drive the prices in paper markets. However, this is a gross over-simplification and does not accurately reflect the process of crude oil price formation. The issue of whether the paper market drives the physical or the other way around is difficult to construct theoretically and test empirically and requires further research.

The report also calls for broadening the empirical research to include the trading strategies of physical players. In recent years, the futures markets have attracted a wide range of financial players including swap dealers, pension funds, hedge funds, index investors, technical traders, and high net worth individuals. There are concerns that these financial players and their trading strategies could move the oil price away from the 'true' underlying fundamentals. The fact remains however that the participants in many of the OTC markets such as forward markets and CFDs which are central to the price discovery process are mainly 'physical' and include entities such as refineries, oil companies, downstream consumers, physical traders, and market makers. Financial players such as pension funds and index investors have limited presence in many of these markets. Thus, any analysis limited to non-commercial participants in the futures market and their role in the oil price formation process is incomplete and also potentially misleading.

The report also makes the distinction between trade in price differentials and trade in price levels. It shows that trades in the levels of the oil price rarely take place in the layers surrounding the physical benchmarks. We postulate that the price level of the main crude oil benchmarks is set in the futures markets; the financial layers such as swaps and forwards set the price differentials depending on quality, location and timing. These differentials are then used by oil reporting agencies to identify the price level of a physical benchmark. If the price in the futures market becomes detached from the underlying benchmark, the differentials adjust to correct for this divergence through a web of highly interlinked and efficient markets. Thus, our analysis reveals that the level of the crude oil price, which consumers, producers and their governments are most concerned with, is not the most relevant feature in the current pricing system. Instead, the identification of price differentials and the adjustments in these differentials in the various layers underlie the basis of the current crude oil pricing system. By trading differentials, market participants limit their exposure to the risks of time, location grade and volume. Unfortunately, this fact has received little attention and the issue of whether price differentials between different markets showed strong signs of adjustment in the 2008-2009 price cycle has not yet received due attention in the empirical literature.

But this leaves us with a fundamental question: what determines the price level of a certain benchmark in the first place? The pricing system reflects how the oil market functions: if price levels are set in the futures market and if market participants in these markets attach more weight to future fundamentals rather than current fundamentals and/or if market participants expect limited feedbacks from both the supply and demand side in response to oil price changes, these expectations will be reflected in the different layers and will ultimately be reflected in the assessed spot price of a certain benchmark.

The current oil pricing system has survived for almost a quarter of a century, longer than the OPEC administered system. While some of the details have changed, such as Saudi Arabia's decision to replace Dated Brent with Brent futures in pricing its exports to Europe and the more recent move to replace WTI with Argus Sour Crude Index (ASCI) in pricing its exports to the US, these changes are rather cosmetic. The fundamentals of the current pricing system have remained the same since the mid 1980s: the price of oil is set by the 'market' with PRAs making use of various methodologies to reflect the market price in their assessments and making use of information in the financial layers surrounding the global benchmarks. In the light of the 2008-2009 price swings, the oil pricing system has received some criticism reflecting the unease that some observers feel with the current system. Although alternative pricing systems could be devised such as bringing back the administered pricing system or calling for producers to assume a greater responsibility in the method of price formation by removing destination restrictions on their exports, or allowing their crudes to be auctioned, the reality remains that the main market players such as oil companies, refineries, oil exporting countries, physical traders and financial players have no interest in rocking the boat. Market players and governments get very concerned about oil price behaviour and its global and local impacts, but so far have showed much less interest in the pricing system and market structure that signalled such price behaviour in the first place.

1. Introduction

The adoption of the market-related pricing system by many oil exporters in 1986-1988 opened a new chapter in the history of oil price formation. It represented a shift from a system in which prices were first administered by the large multinational oil companies in the 1950s and 1960s and then by OPEC for the period 1973-1988 to a system in which prices are set by 'markets'. But what is really meant by the 'market price' or the 'spot price' of crude oil?

The concept of the 'market price' of oil associated with the current pricing regime has often been surrounded with confusion. Crude oil is not a homogenous commodity. There are various types of internationally traded crude oil with different qualities and characteristics which have a bearing on refining yields. Thus, different crudes fetch different prices. In the current system, the prices of these crudes are usually set at a discount or a premium to a benchmark or reference price according to their quality and their relative supply and demand. However, this raises a series of questions. How are these price differentials set? More importantly, how is the price of the benchmark or reference crude determined?

A simple answer to the latter question would be 'the market' and the forces of supply and demand for these benchmark crudes. But this raises additional questions. What are the main features of the spot physical markets for these benchmarks? Do these markets have enough liquidity to ensure an efficient price discovery process? What are the roles of the various financial layers such as the futures markets and other derivatives-based instruments that have emerged around the physical benchmarks? Do these financial layers enhance or hamper the price discovery function? Does the distinction between the different layers of the market matter or have the different layers become so inter-linked that the distinction is no longer meaningful? And if the distinction does matter, what do prices in different markets reflect? It is clear from all these questions that the concept of 'market price' needs to be defined more precisely. The argument that the market determines the oil price has little explanatory power.

The above questions have assumed special importance in the last few years. The sharp swings in oil prices and the marked increase in volatility during the latest 2008-2009 price cycle have raised concerns about the impact of financial layers and financial investors on oil price behaviour.[2] Some observers in the oil industry and in academic institutions attribute the recent behaviour in prices to structural transformations in the oil market. According to this view, the boom in oil prices can be explained in terms of tightened market fundamentals, rigidities in the oil industry due to long periods of underinvestment, and structural changes in the behaviour of key players such as non-OPEC suppliers, OPEC members, and non-OECD consumers.[3] On the other hand, other observers consider that the changes in fundamentals or even in expectations, have not been sufficiently dramatic to justify the extreme cycles in oil prices over the period 2008-2009. Instead, the oil market is seen as having been distorted by substantial and volatile flows of financial investments in deregulated or poorly regulated crude oil derivatives instruments.[4]

The view that crude oil has acquired the characteristics of financial assets such as stocks or bonds has gained wide acceptance among many observers but is disputed by others.[5] Many empirical papers

[2] For a comprehensive overview, see Fattouh (2009).

[3] See, for instance, IMF (2008), World Economic Outlook (October), Washington: International Monetary Fund; Commodity Futures Trading Commission (2008), Interagency Task Force on Commodity Markets Interim Report on Crude Oil; Killian and Murphy (2010).

[4] See, for instance, the Testimony of Michael Greenberger before the Commodity Futures Trading Commission on Excessive Speculation: Position Limits and Exemptions, 5 August 2009. Greenberger provides an extensive list of studies that are in favour of the speculation view.

[5] See, for instance, Yergin (2009). Yergin argues that the excessive 'daily trading has helped turn oil into something new -- not only a physical commodity critical to the security and economic viability of nations but also a financial asset, part of that great instantaneous exchange of stocks, bonds, currencies, and everything else that makes up the world's financial portfolio'.

examine whether the price behaviour of commodities mimics that of financial assets and whether commodity and equity prices have become increasingly correlated.[6] However, the nature of 'financialisation' and its implications are not yet clear in these studies. Discussions and analyses of 'financialisation' of oil markets have partly been subsumed within analyses of the relation between finance and commodity indices which include crude oil. The elements that have attracted most attention have been *outcomes*: correlations between levels, returns, and volatility of commodity and financial indices. However, a full understanding of the degree of interaction between oil and finance requires, in addition, an analysis of interactions, causations and processes such as the investment and trading strategies of distinct types of financial participants; the financing mechanisms and the degree of leverage supporting those strategies; the structure of oil derivatives markets; and most importantly the mechanisms that link the financial and physical layers of the oil market.

One important aspect of 'financialisation' often highlighted is the increasing role that expectations play in the pricing of crude oil. In the case of equities, pricing is based on expectations of a firm's future earnings. In the oil market, expectations of future market fundamentals have increasingly been playing an important role in oil pricing. According to some observers, if there is large uncertainty as to what the long-term oil market fundamentals are, or if perceptions of these fundamentals are highly exaggerated and inflated, then the oil price in the futures market can diverge away from its true underlying fundamental value causing an oil price bubble.[7]

However, unlike a pure financial asset, the crude oil market also has a 'physical' dimension that should anchor these expectations in oil market fundamentals: crude oil is consumed, stored and widely traded with millions of barrels being bought and sold every day at prices agreed by transacting parties. Thus, in principle, prices in the futures market through the process of arbitrage should eventually converge to the so-called 'spot' prices in the physical markets. The argument then goes that since physical deals are transacted at spot prices, these prices reflect existing supply-demand conditions.

In the oil market, however, the story is more complex. To begin with, the 'current' market fundamentals are never known with certainty. The flow of data about oil market fundamentals is not instantaneous and is often subject to major revisions which make the most recent available data highly unreliable. More importantly for this paper, though many oil prices are observed on screens and reported through a variety of channels, it is important to understand what these different prices really mean. Thus, although the futures price often converges to a 'spot' price, it is important to analyse the process of convergence and understand what the 'spot' price really means in the context of the oil market.

Unfortunately, little attention has been devoted to such issues and the processes of price discovery and price formation in oil markets remain under-researched. While this topic can be linked to the current debate on the role of speculation versus fundamentals in the determination of oil prices, it goes beyond the existing debates which have recently dominated policy agendas. This paper offers a fresh and deeper perspective on the current debate by analysing how oil prices are discovered in the current international pricing system, by identifying the various layers relevant for the price formation process and by

[6] See, for instance, Tang and Xiong (2010) who find that commodity prices (more specifically the commodity indices GSCI and DJ-UBS), world equity indices, and the US dollar have become increasingly correlated. Silvennoinen and Thorp (2010) also find an increasing degree of integration between commodities and financial markets especially since the late 1990s. They find that factors such as lower interest rates and corporate bond spreads, US dollar depreciations and financial traders' open positions can explain commodity returns' volatility. In contrast, Büyükşahin, Haig and Robe (2010) find that the relation between commodity and US equity returns did not witness any significant change in the last decade or so. This even applies to periods when markets have witnessed extreme returns. Gorton and Rouwenhorst (2004) find that commodity futures returns are negatively correlated with equity returns and bond returns. This can be explained in terms of the different behaviour of commodities and other asset classes over the business cycle.

[7] See, for instance, Jalali-Naini (2009).

examining and analysing the links between the financial and physical layers in the oil market, which lie at the heart of the current international oil pricing system.

The main purposes of this paper are to analyse the main features of the current crude oil pricing system; to describe the structure of the main benchmarks currently used namely Brent, West Texas Intermediate (WTI) and Dubai-Oman; to clearly identify the various financial layers that have emerged around these physical benchmarks; to analyse the links between the different financial layers and between the financial layers and the physical benchmarks; and then to evaluate how these links influence the price discovery and oil price formation process in the crude oil market. The paper is divided into seven sections. Section 2 provides a historical background to the current international pricing regime analysing the major transformations in the oil market during the last 50 years or so, and the different pricing systems that have been associated with the various market structures. Section 3 discusses the main features of the pricing formulae that constitute the basis of the market-related crude oil pricing system. Section 4 discusses the role of oil pricing reporting agencies in the current oil pricing system. Sections 5, 6 and 7 analyse the three widely used benchmarks in the international oil pricing system Brent, WTI and Dubai, describing their physical base, and analysing the financial layers that have emerged around these physical benchmarks. Section 8 evaluates the links between the physical benchmarks and financial layers and draws the main implications on the oil price formation process. The last section offers some conclusions.

2. Historical Background to the International Oil Pricing System

The emergence of the current oil price system cannot be understood in isolation from previous ones. It has emerged in response to major shifts in the global political and economic structures, changes in power balances, and economic and political transformations that fundamentally changed the structure of the oil market and the supply chain. This chapter discusses the major transformations in the oil market during the period 1950-1988 that led to the emergence of the current international oil pricing system.

The Era of the Posted Price

Until the late 1950s, the international oil industry outside the United States, Canada, the USSR and China was characterised by the dominant position of the large multinational oil companies known as the Seven Sisters or the majors. The host governments did not participate in production or pricing of crude oil and acted only as competing sellers of licences or oil concessions. In return, host governments received a stream of income through royalties and income taxes.

Each of the Seven Sisters was vertically integrated and had control of both upstream operations (exploration, development and production of oil) [8] and to a significant but lesser extent of downstream operations (transportation, refining and marketing). At the same time, they controlled the rate of supply of crude oil going into the market through joint ownership of companies that operated in various countries. The vertical and horizontal linkages enabled the multinational oil companies to control the bulk of oil exports from the major oil-producing countries and to prevent large amounts of crude oil accumulating in the hands of sellers, thus minimising the risk of sellers competing to dispose of unwanted crude oil to independent buyers and thus pushing prices down (Penrose, 1968).

The oil pricing system associated with the concession system until the mid 1970s was centred on the concept of a 'posted' price, which was used to calculate the stream of revenues accruing to host governments. Spot prices, transfer prices and long-term contract prices could not play such a fiscal role. The vertically and horizontally integrated industrial structure of the oil market meant that oil trading became to a large extent a question of inter-company exchange with no free market operating outside these companies' control. This resulted in an underdeveloped spot market. Transfer prices used in transactions within the subsidiaries of an oil company did not reflect market conditions but were merely used by multinational oil companies to minimise their worldwide tax liabilities by transferring profits from high-tax to low-tax jurisdictions. Because some companies were crude long and others crude short, transactions used to occur between the multinational oil companies on the basis of long-term contracts. However, the prices used in these contracts were never disclosed, with oil companies considering this information to be a commercial secret. Oil-exporting countries were also not particularly keen on using contract prices as these were usually lower than posted prices.

Thus, the calculations of the royalty and income tax per barrel of crude oil going to the host governments had to be based on posted prices. Being a fiscal parameter, the posted price did not respond to the usual market forces of supply and demand and thus did not play any allocation function (Mabro, 1984). The multinational oil companies were comfortable with the system of posted prices because it maintained their oligopolistic position, and until the late 1960s OPEC countries were too weak to change the existing pricing system.

The Pricing System Shaken but Not Broken

By the late 1950s, the dominance of the vertically integrated companies was challenged by the arrival of independent oil companies who were able to invest in upstream operations and obtain access to crude oil outside the Seven Sisters' control. In the mid 1950s, Venezuela granted independents (mainly from the

[8] In 1950 the majors controlled 85% of the crude oil production in the world outside Canada, USA, Soviet Russia and China (Danielsen, 1982).

US) some oil concessions, and by 1965 non-majors were responsible for 15% of total Venezuelan production (Parra, 2004).[9] Oil discovery in Libya increased the importance of independents in oil production, for the Libyan government chose as a matter of policy to attract a diverse set of oil companies and not only the majors. In 1965, production by independents in Libya totalled around 580 thousand b/d increasing to 1.1 million b/d in 1968 (Parra, 2004). Competition with the majors also appeared elsewhere. In the late 1950s, Iran signed two exploration and development agreements in the Persian Gulf offshore with non-majors and in 1951, Saudi Arabia entered into an agreement with the Japan Petroleum Trading Company to explore and develop Saudi Arabia's fields in the Neutral Zone offshore area.[10] Crude oil from the Former Soviet Union also began to make its way into the market. The discovery and development of large fields in the Soviet bloc led to a rapid growth in Russian oil exports from less than 100,000 b/d in 1956 to nearly 700,000 b/d in 1961 (Parra, 2004).

While these and other developments led to the emergence of a market for buying and selling crude oil outside the control of the Seven Sisters, the total volume of crude oil from US independents and other companies operating in Venezuela, Libya and the Gulf offshore remained small. Furthermore, the growth of Russian exports came to a halt after 1967 and production levels declined in 1969 and 1970 (Parra, 2004). These factors limited the scope and size of the market and by the late 1960s the majors were still the dominant force both in the upstream and downstream parts of the oil industry (Penrose, 1968). Nevertheless, competitive pressures from other oil producers were partly responsible for the multinational oil companies' decision to cut the posted price in 1959 and 1960. The US decision to impose mandatory import quotas which increased competition for outlets outside the US was an additional factor that placed downward pressure on oil prices. The formation of OPEC in 1960 was an attempt by member countries to prevent the decline in the posted price (Skeet, 1988) and thus for most of the 1960s, OPEC acted as a trade union whose main objective was to prevent the income of its member countries from declining.

The Emergence of the OPEC Administered Pricing System

Between 1965 and 1973, global demand for oil increased at a fast rate with an average annual increase of more than 3 million b/d during this period (BP Statistical Review 2010). Most of this increase was met by OPEC which massively increased its production from around 14 million b/d in 1965 to close to 30 million b/d in 1973. During this period, OPEC's share in global crude oil production increased from 44% in 1965 to 51% in 1973. Other developments in the early 1970s, such as Libya's production cutbacks and the sabotage of the Saudi Tapline in Syria, tightened further the supply-demand balance.

These oil market conditions created a strong seller's market and significantly increased OPEC governments' power relative to the multinational oil companies. In September 1970 the Libyan government reached an agreement with Occidental in which this independent oil company agreed to pay income taxes on the basis of increased posted price and to make retroactive payment to compensate for the lost revenue since 1965. Occidental was the ideal company to pressurise: unlike the majors, it relied heavily on Libyan production and did not have much access to oil in other parts of the world. Soon afterwards, all other companies operating in Libya submitted to these new terms. As a result of this agreement, other oil-producing countries invoked the most favoured nation clause and made it clear that they would not accept anything less than the terms granted to Libya. The negotiations conducted in Tehran resulted in a collective decision to raise the posted price and increase the tax rate.

In September 1973, OPEC decided to reopen negotiations with the companies to revise the Tehran Agreement and seek large increases in the posted price. Oil companies refused OPEC's demand for this increase and negotiations collapsed. As a result, on 16 October 1973, the six Gulf members of OPEC

[9] This share though declined from 1966 onwards.

[10] The volume of oil produced from these concessions did not constitute a serious threat to the majors, but the conclusion of the agreements led to other host governments exerting pressure for better terms in their existing concessions.

unilaterally announced an immediate increase in the posted price of the Arabian Light crude from $3.65 to $5.119. On 19 October 1973, members of the Organization of Arab Oil Producing Countries (less Iraq) announced production cuts of 5% of the September volume and a further 5% per month until 'the total evacuation of Israeli forces from all Arab territory occupied during the June 1967 war is completed and the legitimate rights of the Palestinian people are restored' (Skeet, 1988, quotations in original). In December 1973, OPEC raised the posted price of the Arabian Light further to $11.651. This jump in price was unprecedented. More importantly, the year 1973 represented a dramatic shift in the balance of power towards OPEC. For the first time in its history, OPEC assumed a unilateral role in setting the posted price (Terzian, 1985). Before that date, OPEC had been only able to prevent oil companies from reducing it.

The Consolidation of the OPEC Administered Pricing System

The oil industry witnessed a major transformation in the early 1970s when some OPEC governments stopped granting new concessions[11] and started to claim equity participation in their existing concessions, with a few of them opting for full nationalisation.[12] Demands for equity participation emerged in the early 1960s, but the multinational oil companies downplayed these calls. They became more wary in the late 1960s when they realized that even moderate countries such as Saudi Arabia had begun to make similar calls for equity participation. In 1971, a Ministerial Committee was established to devise a plan for the effective implementation of the participation agreement. OPEC's six Gulf members (Abu Dhabi, Iran, Iraq, Saudi Arabia, Qatar, and Kuwait) agreed to negotiate the participation agreement with oil companies collectively and empowered the Saudi oil Minister Zaki Yamani to negotiate in their name. In October 1972, after many rounds of negotiations, the oil companies agreed to an initial 25% participation which would reach 51% in 1983. Out of the six Gulf States, Saudi Arabia, Abu Dhabi and later Qatar signed the general participation agreement. Iran announced its withdrawal early in 1972. Iraq opted for nationalisation in 1972. In Kuwait, the parliament fiercely opposed the agreement and in 1974 the government took a 60% stake in the Kuwait oil company and called for a 100% stake by 1980. 100% equity participation in Kuwait was achieved in 1976 and Qatar followed suit in 1976-77.

Equity participation gave OPEC governments a share of the oil produced which they had to sell to third-party buyers. It led to the introduction of new pricing concepts to deal with this reality (Mabro, 1984). As owners of crude oil, governments had to set a price for third-party buyers. The concept of official selling price (OSP) or government selling price (GSP) entered at this point and is still currently used by some oil exporters. However, for reasons of convenience, lack of marketing experience and inability to integrate downwards into refining and marketing in oil-importing countries, most of the governments' share was sold back to the companies that held the concession and produced the crude oil in the first place. These sales were made compulsory as part of equity participation agreements and used to be transacted at buyback prices.

The complex oil pricing system of the early 1970s centred on three different concepts of prices: the posted price, the official selling price, and the buyback price. Such a system was highly inefficient as it meant that a buyer could obtain a barrel of oil at different prices (Mabro, 2005). Lack of information and transparency also meant that there was no adjustment mechanism to ensure that these prices converge. Thus, this regime was short-lived and by 1975 had ceased to exist.

[11] As early as 1957, Egypt and Iran started turning away from concessions to new contractual forms such as joint venture schemes and service contracts. In 1964, Iraq decided not to grant any more oil concessions (Terzian, 1985).

[12] Nationalisation of oil concessions in the Middle East extends well before that date. Other than Mossadegh's attempt at nationalisation in 1951, in 1956 Egypt nationalised Shell's interest in the country. In 1958, Syria nationalized the Karatchock oilfields and in 1963 the entire oil sector came under the government control. In 1967, 'Algerisation' of oil companies had already begun and by 1970 all non-French oil interests were nationalized. In 1971, French interests were subject to Algerisation with the government taking 51% of French companies' stakes (Terzian, 1985).

The administered oil pricing regime that emerged in 1974-75 after the short lived episode of the buyback system was radical in many aspects, not least because it represented a complete shift in the power of setting the oil price from multinational companies to OPEC. The new system was centred on the concept of reference or marker price with Saudi Arabia's Arabian Light being the chosen marker crude. In this administered pricing system, individual members retained the OSPs for their crudes, but these were now set in relation to the reference price. The differential relative to the marker price used to be adjusted periodically depending on a variety of factors such as the relative supply and demand for each crude variety and the relative price of petroleum products among other things. The flexibility of adjusting differentials by oil-exporting countries complicated the process of administering the marker price. In the slack market of 1983, OPEC opted for a more rigid system of setting price differentials, but it was unsuccessful.

The Genesis of the Crude Oil Market

Equity participation and nationalisation profoundly affected the structure of the oil industry. Multinational oil companies lost large reserves of crude oil and found themselves increasingly net short and dependent on OPEC supplies. The degree of vertical integration between upstream and downstream considerably weakened. Oil companies retained both their upstream and downstream assets, but their position became more imbalanced and in one direction: the companies no longer had enough access to crude oil to meet their downstream requirements. This encouraged the development of an oil market outside the inter-multinational oil companies' trade. However, during the years 1975−78, OPEC countries remained dependent on multinational oil companies to lift and dispose of the crude oil and initially sold only low volumes through their national oil companies to firms other than the old concessionaires. Thus, at the early stages of the OPEC-administered pricing system, the majors continued to have preferential access to crude which narrowed the scope of a competitive oil market.

The situation changed in the late 1970s with the emergence of new players on the global oil scene. National oil companies in OPEC started to increase the number of their non-concessionaire customers. The appearance of independent oil companies, Japanese and independent refineries, state oil companies, trading houses and oil traders permitted such a development. The pace accelerated during and in the aftermath of the 1979 Iranian crisis. The new regime in Iran cancelled any previous agreements with the oil majors in marketing Iranian oil: they became mere purchasers as with any other oil companies. In Libya, there was a switch away from the main term contract customers, including majors, to new customers − primarily governments and state oil corporations. Other OPEC countries followed suit soon afterwards.

During the 1979 crisis, spot crude prices rose faster than official selling prices. The long-term contract represented an agreement between the buyer and the seller that specified the quantity of oil to be delivered while the price was linked to the OPEC marker price. These contracts obliged producers to sell certain quantities of oil to the majors at the marker price. This meant that oil companies would have been able to capture the entire differential between official selling prices and the spot prices by buying from governments and selling in the spot market or through term contracts with other companies having no direct access to producers. This was unacceptable to producers and governments started selling their crude oil directly to third-party buyers (Stevens, 1985). Faced with a large number of bidders, small OPEC producers such as Kuwait began to place an official mark-up over the marker price. By abandoning their long-term contracts, the producers had the freedom to sell to buyers who offered the highest mark-up over the marker price.[13] The result was that the majors lost access to large volumes of crude oil that were available to them under long-term contracts. This had the effect of dramatically worsening the imbalance

[13] Saudi Arabia was a major exception to this behaviour. They maintained their long-term contracts with the four Aramco concessionaires (Exxon, Chevron, Texaco and Mobil) who continued to obtain oil at the OPEC official price and enjoyed what their competitors referred to bitterly as the 'Aramco advantage'.

within oil companies and reduced the degree of integration between downstream and upstream with the latter becoming only a small fraction of the former.

Faced with this virtual disruption of traditional supply channels, multinational oil companies were forced to enter the market. This had a profound effect on oil markets as de-integration and the emergence of new players expanded the external market where buyers and sellers engaged in arm's-length transactions. The crude market became more competitive and the majority of oil used to move through short-term contracts or the spot market. Prior to these developments, the spot market had consisted of a small number of transactions usually done under distressed conditions, for the disposal of small amounts of crude oil not covered by long-term contracts.

The Collapse of the OPEC Administered Pricing System

The decline in oil demand in the mid 1980s caused by a worldwide economic recession and the growth in non-OPEC crude oil production responding to higher oil prices and taking advantage of new technologies represented major challenges to OPEC's administered pricing system and were ultimately responsible for its demise. New discoveries in non-OPEC countries meant that significant amounts of oil began to reach the international market from outside OPEC.[14] This increase in supply also meant an increase in the number and diversity of crude oil producers who were setting their prices in line with market conditions and hence proved to be more competitive. The new suppliers who ended up having more crude oil than required by contract buyers secured the sale of all their production by undercutting OPEC prices in the spot market. Buyers who became more diverse were attracted to these offers of competitive prices. With the continued decline in demand for its oil, OPEC saw its own market share in the world's oil production fall from 51% in 1973 to 28% in 1985.

Under these pressures, disagreements within OPEC began to surface. Saudi Arabia used to lose market share with every increase in the marker price and hence opposed them while other OPEC members pushed for large increases. At times, disagreements within OPEC led to the adoption of a two-tiered price reference structure. This emerged first in late 1976 when Saudi Arabia and UAE set a lower price for the marker crude than the rest of OPEC.[15] It was repeated in 1980 when Saudi Arabia used $32 per barrel for the marker while the other OPEC members used the per barrel marker of $36. Thus, two new concepts were introduced: the actual marker price which was fixed by Saudi Arabia and the deemed marker price which was fixed by the rest of OPEC (Amuzegar, 1999).

It became clear by the mid 1980s that the OPEC-administered oil pricing system was unlikely to hold for long and OPEC's or more precisely Saudi Arabia's, attempts to defend the marker price would only result in loss of market share as other producers could offer to sell their oil at a discount to the administered price of Arabian Light. As a result of these pressures, the demand for Saudi oil declined from 10.2 million b/d in 1980 to 3.6 million b/d in 1985.

In 1986 and for a short period of time, Saudi Arabia adopted the netback pricing system to restore the country's market share.[16] Soon after other oil exporting countries followed suit. The netback pricing

[14] This process began well before the 1970s. The North Sea attracted oil companies from the early 1960s and the first rounds of leasing were awarded in 1964 and 1965. In 1969, oil was found in the Norwegian sector and in 1970 a major find (the Ekofisk field) was confirmed. In the UK sector, Amoco found in 1969 some oil but it was deemed to be non-commercial. In 1970, BP drilled the exploratory well that found the Forties field. One year later, Shell-Esso discovered the Brent field (Parra, 2004). It is important to note that all these major discoveries preceded the large rise in oil prices. Seymour (1990) shows that half of the increase in non-OPEC supply over the 1975−85 period would have materialised regardless of the level of oil prices.

[15] This two-tier pricing system lasted until July 1977 when Saudi Arabia and UAE announced acceptance of the price $12.70 for the marker crude.

[16] For a detailed analysis of the netback pricing system and the 1986 price collapse, see Mabro (1986).

system provided oil companies with a guaranteed refining margin even if oil prices were to collapse.[17] Under this system, refineries had the incentive to run at a high capacity leading to an oversupply of petroleum products. Lower product prices pulled down crude oil prices and caused the collapse of the crude oil price from $26.69 on 1 July, 1985 to $9.15 a barrel on the 21 July, 1986.[18] Out of the 1986 oil price crisis, the current 'market-related' oil pricing system emerged. However, the transition did not occur instantaneously. In 1987, Saudi Arabia reverted back to official pricing for a short period of time, but its position was untenable as many other oil exporting countries have already made the switch to the more flexible market-related pricing system. The date as to when Saudi Arabia explicitly adopted the pricing formulae is not clear but it might have occurred sometime in 1987 (Horsnell and Mabro, 1993). This opened a new chapter in the history of the oil market which saw OPEC abandon the administered pricing system and transfer the pricing power of crude oil to the so-called market.

[17] It involved a general formula in which the price of crude oil was set equal to the *ex post* product realisation minus refining and transport costs. A number of variables had to be defined in a complex contract including the set of petroleum products that the refiner could produce from a barrel of oil, the refining costs, transportation costs, and the time lag between loading and delivery.

[18] These figures refer to First-month Brent. Source: Petroleum Intelligence Weekly (PIW)

3. The Market-Related Oil Pricing System and Formulae Pricing

The collapse of the OPEC administered pricing system in 1986-1988 ushered in a new era in oil pricing in which the power to set oil prices shifted from OPEC to the so called 'market'. First adopted by the Mexican national oil company PEMEX in 1986, the market-related pricing system received wide acceptance among most oil-exporting countries and by 1988 it became and still is the main method for pricing crude oil in international trade. The oil market was ready for such a transition. The end of the concession system and the waves of nationalisations which disrupted oil supplies to multinational oil companies established the basis of arm's-length deals and exchange outside the vertically and horizontally integrated multinational companies. The emergence of many suppliers outside OPEC and more buyers further increased the prevalence of such arm's-length deals. This led to the development of a complex structure of interlinked oil markets which consists of spot and also physical forwards, futures, options and other derivative markets referred to as paper markets. Technological innovations that made electronic trading possible revolutionised these markets by allowing 24-hour trading from any place in the world. It also opened access to a wider set of market participants and allowed the development of a large number of trading instruments both on regulated exchanges and over the counter.

Spot Markets, Long-Term Contracts and Formula Pricing

Physical delivery of crude oil is organised either through the spot (cash) market or through long-term contracts. The spot market is used by transacting parties to buy and sell crude oil not covered by long-term contractual arrangements and applies often to one-off transactions. Given the logistics of transporting oil, spot cargoes for immediate delivery do not often take place. Instead, there is an important element of forwardness in spot transactions which can be as much as 45 to 60 days. The parties can either agree on the price at the time of the agreement, in which case the sport transaction becomes closer to a 'forward' contract.[19] More often though, transacting parties link the pricing of an oil cargo to the time of loading.

Long-term contracts are negotiated bilaterally between buyers and sellers for the delivery of a series of oil shipments over a specified period of time, usually one or two years. They specify, among other things, the volumes of crude oil to be delivered, the delivery schedule, the actions to be taken in case of default, and above all the method that should be used in calculating the price of an oil shipment. Price agreements are usually concluded on the method of *formula pricing* which links the price of a cargo in long-term contracts to a market (spot) price. Formula pricing has become the basis of the oil pricing system.

Crude oil is not a homogenous commodity. There are various types of internationally traded crude oil with different qualities and characteristics. Crude oil is of little use before refining and is traded for the final petroleum products that consumers demand. The intrinsic properties of crude oil determine the mix of final petroleum products. The two most important properties are density and sulfur content. Crude oils with lower density, referred to as light crude, usually yield a higher proportion of the more valuable final petroleum products such as gasoline and other light products by simple refining processes. Light crude oils are contrasted with heavy ones that have a low share of light hydrocarbons and require a much more complex refining process such as coking and cracking to produce similar proportions of the more valuable petroleum products. Sulfur, a naturally occurring element in crude oil, is an undesirable property and refiners make heavy investments in order to remove it. Crude oils with high sulfur are referred to as sour crudes while those with low sulfur content are referred to as sweet crudes.

Since the type of crude oil has a bearing on refining yields, different types of crude streams fetch different prices. The light/sweet crude grades usually command a premium over the heavy/sour crude grades. Given the large variety of crude oils, the price of a particular crude oil is usually set at a discount or at a

[19] Although spot transactions contain an element of forwardness, they are considered as commercial agreements under US law and are not subject to the regulation of the Commodity Exchange Act.

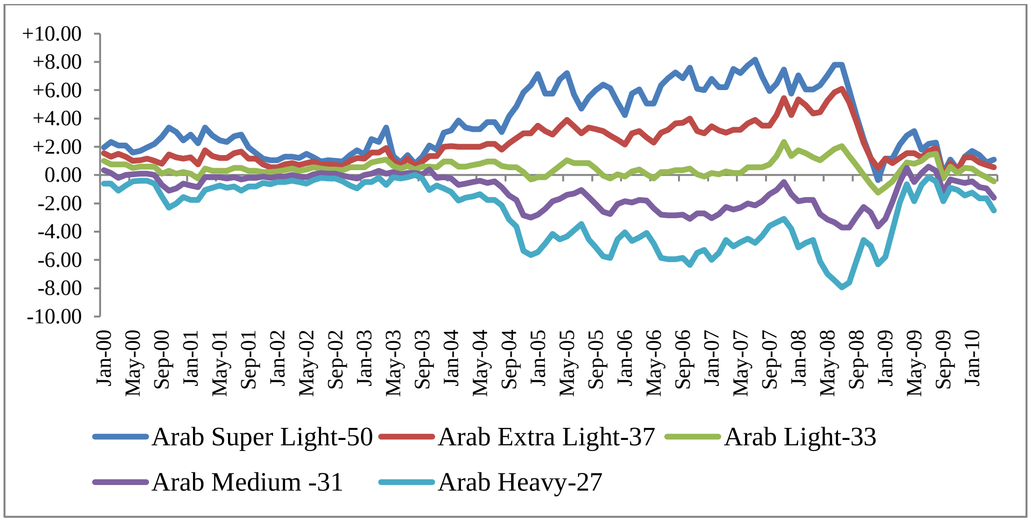
premium to a marker or reference price. These references prices are often referred to as benchmarks. The formula used in pricing oil in long-term contracts is straightforward. Specifically, for crude oil of variety *x*, the formula pricing can be written as

$$P_x = P_R \pm D$$

where P_x is the price of crude *x*; P_R is the benchmark crude price; and *D* is the value of the price differential. The differential is often agreed at the time when the deal is concluded and could be set by an oil exporting country or assessed by price reporting agencies.[20] It is important to note that formula pricing may apply to all types of contractual arrangements, be they spot, forward or long term. For instance, a spot transaction in the crude oil market, is - pricing wise - an agreement on a spot value of the differential between the physical oil traded and the price of an agreed oil benchmark, which fixes the absolute price level for such trade, normally around the time of delivery or the loading date.

Differences in crude oil quality are not the only determinant of crude oil price differentials however. The movements in differentials also reflect movements in the Gross Products Worth (GPW) obtained from refining the reference crude *R* and the crude *x*.[21] Thus, price differentials between the different varieties of crude oil are not constant and change continuously according to the relative demand and supply of the various crudes which in turn depend on the relative prices of petroleum products. Figure 1 plots the differential that Saudi Arabia applied to its crude exports to Asia for its different types of crude oil relative to the Oman/Dubai benchmark during the period 2000-2010 (January). As seen from this figure, the discounts and premiums applied are highly variable. For instance, at the beginning of 2008, the differentials between Arab Super Light and Arab Heavy widened sharply to reach more than $15 a barrel; fuel oil, a product of heavy crude, was in surplus while the demand for diesel, a product of lighter crudes, was high. In the first months of 2009, the price differential between heavy and light crude oil narrowed to very low levels as the implementation of OPEC cuts reduced the supply of heavy crude and increased the relative value of heavy-sour crudes.

Figure 1: Price Differentials of Various Types of Saudi Arabia's Crude Oil to Asia in $/Barrel



Source: Petroleum Intelligence Weekly Database

[20] Official formula pricing refers to the process of setting the differential in relation to a benchmark with the resultant price known as official formula prices. This should be distinguished from official selling prices in which the government sets the price on an outright basis.

[21] Individual crudes have a particular yield of products with a gross product worth (GPW). GPW depends both on on the refining process and the prices at which these products are sold.

The differential to a benchmark is independently set by each of the oil-producing countries. For many countries, it is usually set in the month preceding the loading month and is adjusted monthly or quarterly. For instance, for the month of May, the differential is announced in the month before, i.e. April based on information and data about GPW available in the month of March.[22] Since the process of setting price differentials involves long time lags and is based on old information and data, the value of the price differential does not often reflect the market conditions at the time of loading and much less so by the time the cargo reaches its final destination. In the case of multiple transactions under a long-term contract, buyers can be compensated by sellers by adjusting downwards the differential in the next rounds if the price proves to be higher than what is warranted by market conditions at the time of loading or at delivery. This continuous process of adjusting differentials is inevitable given that setting the differential is based on lagged data and if oil exporters wish to maintain the competitiveness of their crudes.

In other countries such as Abu Dhabi and Qatar, the governments do not announce price differentials, but rather an outright price known as the official selling price (OSP). These are, however, strongly linked to Dubai-Oman benchmark and thus, one can assume that outright prices contain an implicit price differential and hence are close to formula prices (see Horsnell and Mabro, 1993; Argus, 2010).[23]

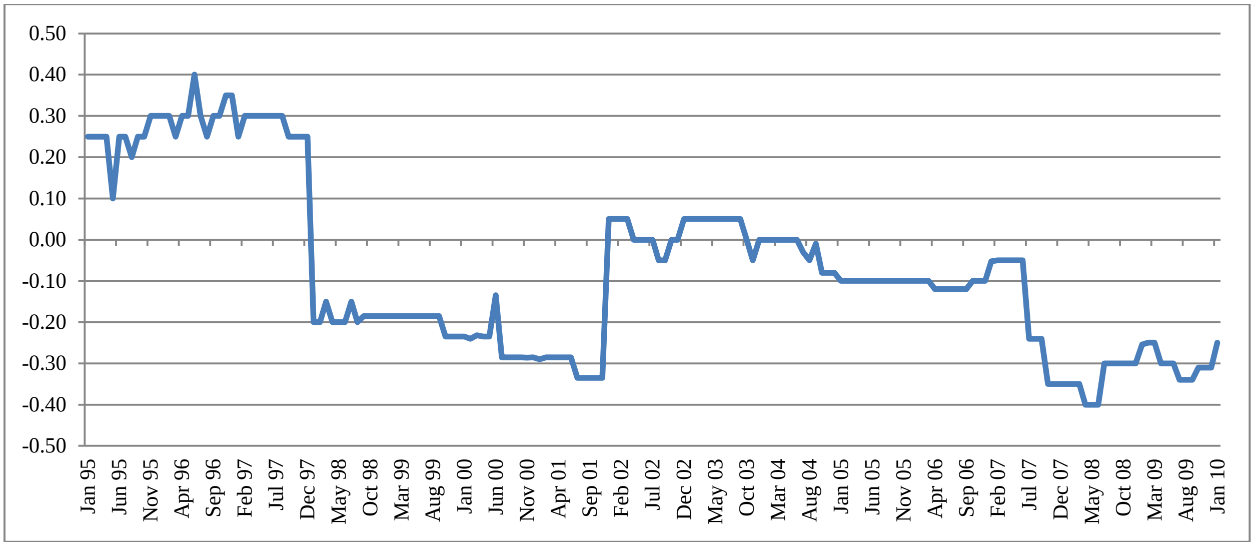
In setting the differential, an oil-exporting country will not only consider the differential between its crude and the reference crude, but has also to consider how its closest competitors are pricing their crude in relation to the reference crude. This implies that the timing of setting the differential matters, especially in a slack market. Oil-exporting countries that announce their differentials first are at the competitive disadvantage of being undercut by their closest competitors. This can induce them to delay announcement of the differential or, in the case of multiple transactions, compensate the buyers by adjusting the differential downward in the next rounds. Competition between various exporters implies that crude oils of similar quality and destined for the same region tend to trade at very narrow differentials. Figure 2 below shows the price differential between Saudi Arabia Light (33.0 API) and Iranian Light (33.4 API) destined to Asia. As seen from this graph, the differentials are narrow not exceeding 30 cents most of the time although on some occasions, the differentials tend to widen. Such large differentials do not tend to persist as adjustments are made to keep the crude oil competitive. In the mid 1990s, Saudi Arabia Light was trading at a premium to the Iranian Light, but this premium turned into discount in the slack market conditions of 1998. In the period 2002 to 2004, the two types of crude oil were trading almost at par, but since 2007, Saudi Arabian Light has been trading at a discount, making its light crude more competitive compared to the Iranian Light, perhaps in an attempt by Saudi Arabia to maximise its export volume to Asia or due to mispricing on the part of the Iranian National Oil Company.

The above discussion focused only on the pricing mechanism implemented by an oil exporting country via its national oil company. The value of the differential does not need not to be set by an oil producing country and can be assessed by price reporting agencies.

[22] For details see Horsnell and Mabro (1993).

[23] Abu Dhabi and Qatar set the OSP retroactively so that the OSP announced in the month of October applies to cargoes that have already been loaded in the month of September while Oman and Dubai dropped retroactive pricing when they moved from Platts Oman-Dubai to DME Oman in August 2007.

Figure 2: Differentials of Term Prices between Saudi Arabia Light and Iran Light Destined to Asia (FOB) (In US cents)



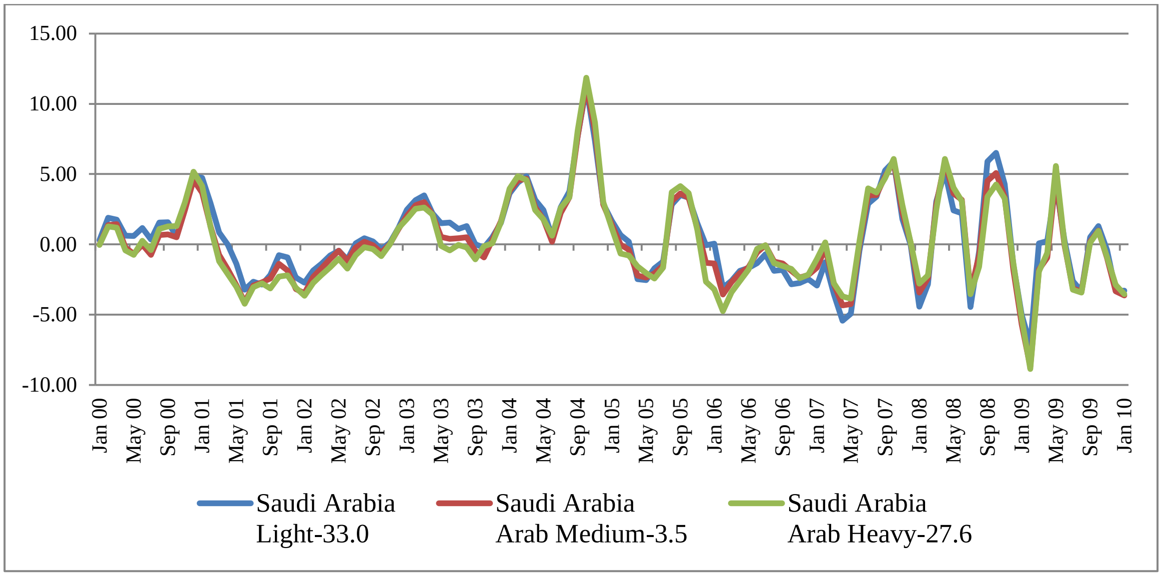
Source: Oil Market Intelligence Database

The ‘equivalence to the buyer’ principle, which means that in practice prices of crudes have equivalent prices at destination, adds another dimension to the pricing formulae. The location in which prices should be compared is not the point of origin but must be closer to the destination where the buyer receives the cargo. Since the freight costs vary depending on the export destination, some formulae also take into account the relative freight costs between destinations. Specifically, they allow for the difference between the freight costs involved in moving the reference crude from its location to a certain destination (e.g. Brent from Sollum Voe to Rotterdam) and the costs involved in moving crude *x* from the oil country’s terminal to that certain destination (e.g. Arabian Light from Ras Tanura to Rotterdam). In such cases, the sale contract is close to a cost, insurance and freight (CIF) contract. This is in contrast to a free on board (FOB) contract which refers to a situation in which the seller fulfils his obligations to deliver when the goods have passed over the ship’s rail. The buyer bears all the risks of loss of or damage to the goods from that point as well as all other costs such as freight and insurance.

A major advantage of formula pricing is that the price of an oil shipment can be linked to the price at the time of delivery which reflects the market conditions prevailing. When there is a lag between the date at which a cargo is bought and the date of arrival at its destination, there is a big price risk. Transacting parties usually share this risk through the pricing formula. Agreements are often made for the date of pricing to occur around the delivery date. For instance, in the case of Saudi Arabia’s exports to the United States up to December 2009, the date of pricing varied between 40 to 50 days after the loading date. The price used in contracts could be linked to the price of benchmark averaged over 10 days around the delivery date, which rendered the point of sale closer to destination than the origin. In 2010, Saudi Arabia shifted to Argus Sour Crude Index (ASCI) and it currently uses the trade month (20 day minimum) average of ASCI prices for the trade month applying to the time of delivery.

Oil exporters may have different pricing policies for different regions. For instance, for Saudi exports to the US, the price that matters most is the cost of shipment at the delivery point. For its exports to Asia, the pricing point is free on board and hence the price that matters most is the price at the loading terminal. Figure 3 below shows the price difference between crude delivered to the US Gulf Coast and the price sold at FOB to Asia for different variety of crude oils. As seen from this graph, the price differential is highly variable depending on the relative demand and supply conditions between these two markets and the degree of competition from alternative sources of supply. While in the US, Saudi Arabia faces tough competition from many suppliers including domestic ones and hence its crude has to be competitive at destination, the strong growth in Asian demand and the limited degree of competition in Asia give rise to an 'Asian premium'. Hence, in some occasions the price of a cargo delivered to the US is less than the FOB price to Asia despite the fact that it takes longer for a cargo to reach the US.

Figure 3: Difference in Term Prices for Various Crude Oil Grades to the US Gulf (Delivered) and Asia (FOB)



Source: Oil Market Intelligence

Benchmarks in Formulae Pricing

At the heart of formulae pricing is the identification of the price of key 'physical' benchmarks, such as West Texas Intermediate (WTI), the ASCI price, Dated Brent (but also called Dated North Sea Light, North Sea Dated, Dated BFOE)[24] and Dubai. The prices of these benchmark crudes, often referred to as 'spot' market prices, are central to the oil pricing system. The prices of these benchmarks are used by oil companies and traders to price cargoes under long-term contracts or in spot market transactions; by futures exchanges for the settlement of their financial contracts; by banks and companies for the settlement of derivative instruments such as swap contracts; and by governments for taxation purposes.[25]

Table 1 below lists some of the various benchmarks used by key oil exporters. As seen from the table, countries use different benchmarks depending on the export destination. For instance, Iraq uses Brent for its exports to Europe, a combination of Oman and Dubai for its exports to Asia, and until very recently WTI for its exports for the US. In 2010, Saudi Arabia, Kuwait and Iraq switched to the Argus Sour Crude Index (ASCI) for exports destined to the US. Mexico uses quite a complex formula in pricing its exports to the US which includes a weighted average of the prices of West Texas Sour (WTS), Louisiana Light Sweet (LLS), Dated Brent, and High Sulfur Fuel Oil (HSFO). For its exports to Europe, Mexico uses both high and low sulfur fuel oil (FO) and Dated Brent.

[24] Platts continues to call the physical market Dated Brent or Dated North Sea Light while Argus calls it North Sea Dated. As shall be discussed later, the continued use of the term 'Dated Brent' by Platts and much of the industry is not an arcane point, because the price of physical Dated Brent cargoes will be different from its 'Dated Brent' price. The prices of physical Brent, Forties and Oseberg all differ from the (Argus) North Sea Dated/(Platts) Dated Brent value.

[25] Some governments (Oman, Qatar, Abu Dhabi, Malaysia, and Indonesia) do not use benchmarks at all and instead set their own official selling prices (OSPs) on a monthly basis. These can be set retroactively or retrospectively.

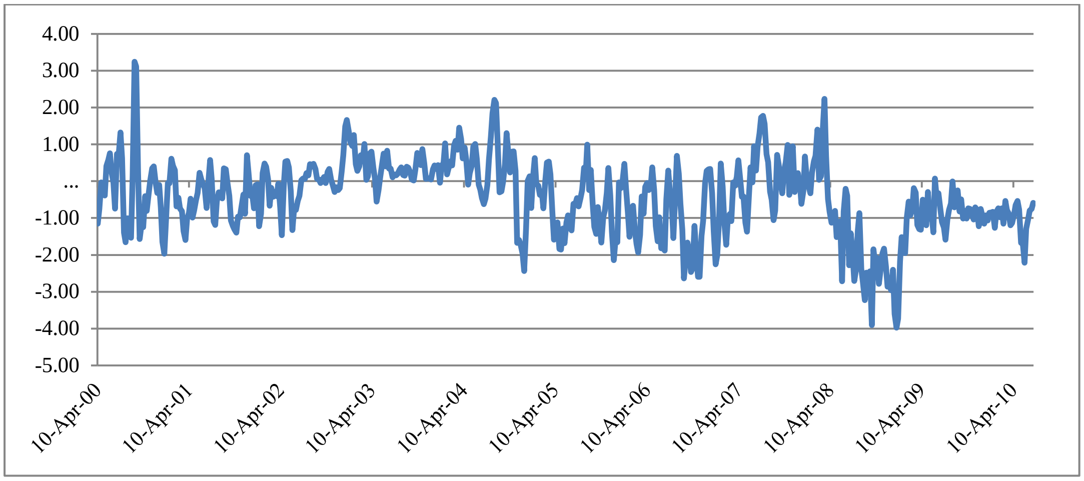
Table 1: Main Benchmarks Used in Formula Pricing

	Asia	Europe	US
Saudi Arabia	Oman and Dubai	BWAVE from Jul.'00, Dated Brent Until Jun.'00	ASCI from Jan.2010, WTI until Dec.'09
Iran	Oman and Dubai	BWAVE from Jan.'01, Dated Brent Until Dec.'00	
Kuwait	Oman and Dubai	BWAVE from Jul.'00, Dated Brent Until Jun.'00	ASCI from December 2009 ; Previously WTI
Iraq (Basrah Blend)	Oman and Dubai	Dated Brent	ASCI from April 2010, Previously WTI Second Month
Nigeria		Dated Brent	Brent
Mexico (Maya Blend)		Dated Brent x0.527 + 3.5%HSFO x0.467 - 1%FO x.25 + 3.5%FO x0.25’	WTS x0.4 + 3%HSFO x0.4 + LLS x0.1 + Dtd.Brent x0.1

The pricing may be based on ‘physical’ benchmarks such as Dated Brent or on the financial layers surrounding these physical benchmarks such as the Brent Weighted Average (BWAVE), which is an index calculated on the basis of prices obtained in the Brent futures market. Specifically, the BWAVE is the weighted average of all futures price quotations that arise for a given contract of the futures exchange during a trading day, with the weights being the shares of the relevant volume of transactions on that day. Major oil exporters such as Saudi Arabia, Kuwait and Iran use BWAVE as the basis of pricing crude exports to Europe. As seen from Figure 4 below, the price differential between Dated Brent and BWAVE is quite variable with the differential in some occasions exceeding plus or minus three dollars per barrel. This is expected as BWAVE is considerably less prompt than Dated Brent and thus variability between the two should consider this time basis issue.[26] Therefore, the choice of benchmark has serious implications on government revenues. This is perhaps most illustrated in the recent shift from WTI to ASCI by some Gulf exporters. Figure 5 plots the price differential between the two US benchmarks WTI and ASCI. WTI traded at a premium to ASCI through most of this time but occasionally (four significant times) WTI moved to a discount when WTI collapsed versus other world benchmarks, with the WTI discount to ASCI reaching close to $8/barrel on 12 February 2009. The January/ February events prompted Saudi Arabia to consider alternatives to Platts WTI cash assessment.

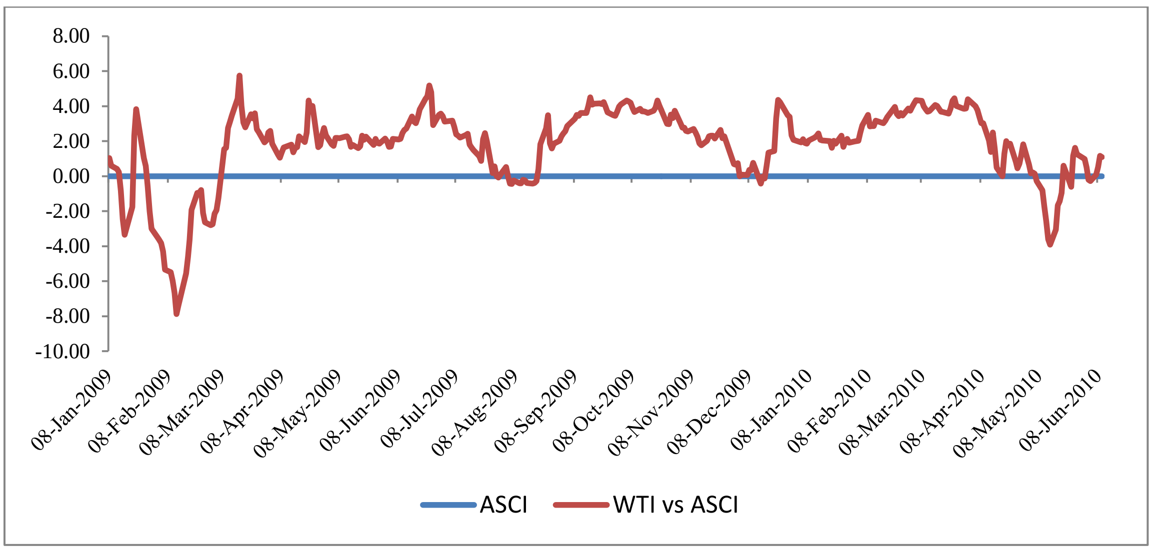
[26] Furthermore, as volatility is strongly backwardated itself along its own forward curve for most markets, this is also a relevant factor.

Figure 4: Price Differential between Dated Brent and BWAVE ($/Barrel)



Source: Petroleum Intelligence Weekly

Figure 5: Price Differential between WTI and ASCI ($/Barrel) (ASCI Price=0)



Source: Argus

Given the central role that benchmarking plays in the current oil pricing system, it is important to highlight some of the main features of the most widely used benchmarks. First, unlike the futures market where prices are observable in real time, the reported prices of physical benchmarks are 'identified' or 'assessed' prices. These assessments are carried out by oil pricing reporting agencies, the two most important of which are Platts and Argus.[27] Assessments are needed in opaque markets such as oil where physical transactions concluded between parties cannot be directly observed by market participants. After all, parties are under no obligation to report their deals. Assessments are also needed in illiquid markets

[27] There are other PRAs but these are often more specialised such as OMR (focus on Germany, Austria, and Switzerland), APPI (focus on Asia), RIM (focus on Asia), ICIS-LOR (focus on petrochemicals) and OPIS (focus on US). In December 2010, Platts announced an agreement to acquire OPIS. The acquisition is expected to be completed in the first half of 2011, subject to regulatory approval.

where not enough representative deals or where no transactions take place. Oil reporting agencies assess their prices based on information on concluded deals which they observe, or bids and offers, and failing that on market talk, other private and public information gathered by reporters, and information from financial markets. It is important to note that PRAs do not use in all markets a hierarchy of information cascading down from deals to bids and offers, which would imply that deals are the best price discovery and bids/offers are a poorer alternative. The methodology may vary from market to market in accordance with the published methodology for that market. In some markets, bid/offer information takes precedence over deals in identifying the published price – e.g. if the deal is either not representative of the market as defined in the methodology, or was done earlier or later in the day to the prevailing depth of market. In other markets, price identification relies on observed deals. For instance, Argus' main benchmark ASCI is entirely deal based. Most however accept that a done deal does represent the highest form of 'proof' of value, unless there is a supervening issue with the trade's conduct. If assessments are intended to represent an end-of day price, analogous to a futures 'settlement ' however, a fully evidenced bid/offer spread at a later point when markets have clearly moved in value is an acceptable proxy in the absence of a trade .

Sometimes a distinction is made between prices identified through observed deals or transactions using a direct mathematical formula such as volume-weighted average (referred to as an index) and prices identified through a process of interpretation based on bids and offers, market surveys, and other information gathered by reporters (referred to as price assessment) (see Argus, 2010). The choice of the method varies across markets and depends on the structure of market, particularly on the degree of market opaqueness and liquidity. While an index is suitable for markets with high trading liquidity and transparency, assessments are more suitable in opaque and illiquid markets. In this paper, we do not make this distinction and refer to both categories as price assessment. However, regardless of the method used, there is an important element of subjectivity involved as the methodology has to be decided by managers and editors. The choice of methodology (the time window in which the price is assessed, the grade specification, location) in an index based system is just as subjective as price assessment. In that respect, one approach (index or assessment) is no more subjective than the other.

Second, these agencies do not always produce the same price for the same benchmark as these pursue different methodologies in their price assessments. Even if price quotations are based on a mechanical methodology of deals done, two price reporting services could publish different prices for the same crude because their price identification process and the deals they include in the assessment could be different. For example, one PRA might use a volume weighted average of transactions between 9.00am and 5.00pm while another PRA might use last trade or open bid/offer at specified period of time. Or one PRA might include transactions within a 10-21 day price range and another includes transactions in a 10-15 day price range. Or one PRA might only include fixed-price transactions and another include fixed-price and formula-related transactions.

Third, the nature of these benchmarks tends to evolve over time. Although the general principle of benchmarking has remained more or less the same over the last twenty-five years, the details of these benchmarks in terms of their liquidity and the type of crudes that are included in the assessment process have changed dramatically over that period. The assessment of the traditional Brent benchmark now includes the North Sea streams Forties, Oseberg and Ekofisk (BFOE) and that of Platts Dubai price includes Oman and Upper Zakum. These streams are not of identical quality and often fetch different prices. Thus, the assessed price of a benchmark does not always refer to a particular 'physical' crude stream. It rather refers to a constructed 'index'[28] which is derived on the basis of a simple mathematical formula which takes the lowest priced grade of the different component crudes to set the benchmark.

[28] This may take the form of a matrix of closely-related prices which use the total physical liquidity by engineering price floors and caps to reduce or eliminate the possibility of price distortion or skews.

Table 2 below summarises some basic statistics of the main international benchmarks: BFOE in the North Sea, WTI and ASCI in the US, and Dubai-Oman in the Gulf. In terms of production, the underlying physical base of the benchmark amounts to slightly more than 3 million b/d, i.e., around 3.5% of global production. In terms of liquidity, there is wide difference across benchmarks. While in the US the number of spot trades per calendar month is close to 600, the number of spot trades does not exceed three per month in the case of Dubai. The divergence in liquidity across benchmarks reflects the low underlying physical base and the different nature of benchmarks where US crudes are pipeline crudes with small trading lots whereas Brent and Dubai are waterborne crudes with large trading lots. Table 2 also shows that the degree of concentration in traded volumes varies considerably across markets. From the sellers' side, Dubai, Oman and Forties exhibit a high degree of concentration in the total volume of spot trades especially when compared to US markets. From the buyers' side, Dubai and Forties exhibit a high degree of concentration whereas Oman compares favourably with other benchmarks.

Table 2: Some Basic Features of Benchmark Crudes

First-quarter 2010 averages by Argus	**ASCI**	**WTI CMA + WTI P-Plus**	**Forties**	**BFOE**	**Dubai**	**Oman**
Production (MBPD)	736	300-400	562	1,220	70-80	710
Volume Spot Traded (MBPD)	579	939	514	635	86	246
Number of Spot Trades per Cal Month	260	330	18	98	3.5	10
Number of Spot Trades Per Day	13	16	<1	5	<1	<1
Number of Different Spot Buyers per Cal Month	26	27	7	10	3	5
Number of Different Spot Sellers per Cal Month	24	36	6	9	3	6
Largest 3 Buyers % of Total Spot Volume	43%	38%	63%	72%	100%	50%
Largest 3 Sellers % of Total Spot Volume	38%	51%	76%	56%	100%	80%

Source: Argus

Notes: Daily statistics are per trade day, except production which is per calendar day; Forties: The physical grade usually sets North Sea Dated/Dated Brent; BFOE: Forward cash contracts deliverable as physical BFOE cargoes, used in setting the flat price against which North Sea Dated is calculated; Oman: Excludes physical deliveries through DME. Estimated deliveries on DME contacts are 300,000-400,000 barrels per day; WTI: Includes cash market trade for WTI Calendar Month Average and WTI P-Plus. Cash market at Cushing no longer trades except at last three days of trade month as spread for 2nd month. Roll trades are not included here. Also does not include any volumes on CME Nymex futures.

Finally, in the last two decades or so, many financial layers (paper markets) have emerged around these benchmarks. These include the forward market (in Brent), swaps, futures, and options. Some of the instruments such as futures and options are traded on regulated exchanges such as ICE and CME Group, while other instruments, such as swaps and forward contracts, are traded bilaterally over the counter (OTC). Nevertheless, these financial layers are highly interlinked through the process of arbitrage and the development of instruments that link the various markets together such as the Exchange of Futures for Swaps (EFS) which allow traders to roll positions from futures to swaps and vice versa. Over the years, these markets have grown in terms of size, liquidity, sophistication and have attracted a diverse set of players, both physical and financial. These markets have become central for market participants wishing to hedge their risk and to bet (or speculate) on oil price movements. Equally important, these financial layers have become central to the oil price identification process. In Sections 5, 6 and 7, we discuss the main benchmarks used in the current oil pricing system and the financial layers surrounding these benchmarks.

4. Oil Price Reporting Agencies and the Price Discovery Process

The oil price reporting agencies (PRAs) are an important component of the oil industry. The prices that these agencies identify or assess underlie the basis of long-term contracts, spot market transactions, futures markets contracts and derivatives instruments. Some PRAs argue that through their methodological structure for reporting physical transactions, they act as 'a mirror to the trade' and provide 'transparency on what would otherwise be a collection of bilateral deals'.[29] However, as argued by Horsnell and Mabro (1993:155) oil PRAs are

> far more than mere observers of crude oil and oil product markets. If they were, then their only role would be to add to the price transparency of the market. However, deals worth hundreds of millions of dollars per day ride on published assessment and the nature and structure of oil reporting create trading opportunities and new markets and affect the behaviour of oil traders. Price reporting does more than provide a mirror for oil markets; the reflection in the mirror can affect the image itself.

Indeed, in their attempt to identify the price that reflects accurately the market value of the oil barrel, PRAs enter into the decision-making territory that can influence market structure. For instance, Platts decides on the time of pricing of oil (the time stamping), the width of the Platt's window, the size of the parcel to be traded, the process of delivery, and the time of delivery of the contract. PRAs make these decisions on the basis of regular consultations with the industry. In return, PRAs influence the trading strategies of the various participants and their reporting policies. In fact, new markets and contracts may emerge to hedge the risks arising from some of the decisions that PRAs make. Even when price assessments are based on observed transactions and mathematical formula, there is still an important element of decision-making involved as this entails the choice about the assumptions behind the methodology. Editors and managers in PRAs choose how to build the index (in the case of Argus) and how to allow for non-deals-based methodologies in case of a lack of deals.

While PRAs have been an integral part of the crude oil market especially since the shift to the market-related pricing system in 1986[30], their role has recently been attracting considerable attention. In the G20 summit in Korea in November 2010, the G20 leaders called on 'the IEF, IEA, OPEC and IOSCO to produce a joint report, by the April 2011 Finance Ministers' meeting, on how the oil spot market prices are assessed by oil price reporting agencies and how this affects the transparency and functioning of oil markets '.[31] In its latest report in November 2010, IOSCO points that 'the core concern with respect to price reporting agencies is the extent to which the reported data accurately reflects the cash market in question'.[32] As discussed below, the accuracy of price assessments heavily depends on large number of factors including the quality of information obtained by the PRA, the internal procedures applied by the PRAs and the methodologies used in price assessment.

To evaluate the role of PRAs in the oil market, it is important to look at three inter-related dimensions: the methodology used in identifying the oil price; the accuracy of price assessments;[33] and the internal measures that PRAs implement to protect their integrity and ensure an efficient price assessment process. There is a fundamental difference in the methodology and in the philosophy underlying the price assessment process between the various pricing reporting agencies. As a result, different agencies may produce different prices for the same benchmark. Even if price quotations are based on a mechanical methodology of deals done, two price reporting services could publish different prices for the same crude

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[29] Argus Response to the 'Report of the Working Group on the Volatility of Oil Prices' chaired by Professor Jean-Marie Chevalier, p.5.

[30] PRAs assessment were already widely used in the price formation process for refined products prior to 1986.

[31] G-20 Seoul Summit 2010, THE SEOUL SUMMIT DOCUMENT, Paragraph 61.

[32] IOSCO (2010), Task Force on Commodity Futures Markets: Report to the G20, November 2010, p. 17.

[33] Though other attributes such as representativeness and usefulness could also be included.

because their mechanical price identification process could be different. This raises the issue of which of the methods generates a more accurate price assessment. Given that assessed prices underlie long-term contracts, spot transactions and derivatives instruments, even small differences in price assessments between PRAs have serious implications for exporters' revenues and financial flows between parties in financial contracts.

PRAs use a wide variety of methods to identify the oil price which may include the volume weighted average system, low and high deals done, and market-on-close (MOC). In January 2001, Platts stopped using the volume-weighted average system and replaced it with the MOC methodology.[34] In this system, Platts sets a time window, known as the Platts window, and only deals transacted within this time window are used to assess the oil price.[35] The price is assessed on the basis of concluded deals, or failing that, on bids and offers. Assessment will also make use of information from financial layers about spreads and derivative 'to help triangulate value'.[36] Thus, the MOC can be thought of a structured system for gathering information on the basis of which Platts assesses the daily price of key physical benchmarks. In a way, it is similar to a futures exchange where traders make bids and offers, but with two major differences: the parties behind the bids and offers are known, and Platts decides on the information to be considered in the assessment, i.e., the information passes through the Platts filter. These price assessments are then transmitted back to the market through a variety of channels. The reason for the shift to MOC is a concern that 'an averaging system for price determination could result in assessments that lag actual market levels as deals done early in an assessment period at a level that is not repeatable, could mathematically drag prices down or up' (Platts, 2010a:7).[37] Thus, Platts emphasises the time sensitivity of its assessed prices which are 'clearly time-stamped' on a daily basis.[38] Time stamping not only allows for an accurate reflection of price levels at particular point in time, but also for accurate assessment of time spreads and inter-crude spreads.

Both the volume-weighted average method and the MOC have received their share of criticism. While the volume-weighted average method allows the inclusion of a large number of deals and hence is more representative, the method has been criticised as it

[34] In the US, Platts used a volume weighted average for domestic crude. But for products, it has always used a low and high of deals done. In the WTI crude market prior to 2001 Platts used a volume weighted average of a 30-minute window. In Asia, Platts used the window or page 190, its first 'market on close', also before 2001. The market on close went global for Platts in 2001.

[35] It is important to note that the window opens all day and Platts will accept trades, bids and offers at any time of the day. But only deals transacted within a specified period of time (for instance from 4:00 to 4:30 for European crudes) are considered for assessing the price for that day. Some argue that this may encourage traders to present their bids/offers to Platts during this time window in order to maximize their impact on prices.

[36] Thorne, S. (2010), 'A User guide to Platts Assessment Processes', Presentation at the Platts Crude Oil Methodology Forum 2010, London, May.

[37] Platts (2010a), Methodology and Specifications Guide: Crude Oil, *The McGraw Hill Companies*, October.

[38] Some commentators consider that through its window, Platts is able to establish the marginal price of oil, which in principle should set price for the rest of the market. It is not clear what is meant by the marginal price, but in terms of theory, the closest one can think of the Platts' window is in terms of the Walrasian auctioneer. The Walrasian auctioneer is a fictitious construct who aggregates traders' demand and supplies to find a market clearing price, through a series of auctions. While Platts window resembles the Walrasian auctioneer, it differs fundamentally in many respects such as the existence of transactions costs, barriers to entry and the fact that the auctioneer does not perform a passive role in the market. It decides who enters the market and when to the set the price. It has also been long realised that trading has a timing dimension. While over time, the number of buyers and sellers may be equal, at any particular the time, this is not guaranteed in which case it is not possible to find a market clearing price (Demsetz, 1968). This could be overcome by participants paying an immediacy premium in which case the equilibrium will be characterised by two demand and supply curves and two prices. Furthermore, the literature shows that market structure such as the number of players, their size, the timing of entry matters and could affect the trading price. Therefore, the actual mechanism used to set the price is not simply a channel, but is an input into the price and as such cannot be ignored (see O'Hara, 1997).

may result in an index that is out of step and not reflective of the actual market price prevailing at the close of the day. This would especially be the case on days with high volatility. Trade- weighted averages may also be distorted by the pattern of trading liquidity over the day…. A key weakness in all trade-weighted average assessments is that they will lag the market price. They always reflect a price that 'was' rather than the price that 'is.' (Platts, 2010b:6).[39]

The main criticism of the MOC methodology is that the Platts window often lacks sufficient liquidity and may be dominated by few players which may hamper the price discovery process. For instance, Argus, Platts' main competitor, argues that in US crude markets

> MOC methodology would work if the industry poured liquidity into the window. Without this liquidity, the methodology is left to assess the value at the close based on bids, offers and other related factors. This means that the price derived from an MOC assessment can diverge widely from a weighted average of all deals done in the trading day.[40]

This divergence is expected given that the average price is different from the stamped price and the convergence of the two is just a statistical accident if it ever happens.

Argus conducted a study on the US crude oil market in 2007 which compares the spot market traded volume inside the window with the volume traded during the entire day. The study finds that the volume traded within the Platts window constitutes only a very small fraction of daily traded volumes, as seen in Table 3 below. This applies to a wide variety of US crudes. Argus argues that such low liquidity and 'complete lack of participant breadth' raise 'serious questions about the efficiency of price discovery' in the US oil market.[41]

Table 3: Spot Market Traded Volumes in May 2007 (May traded during May Trade Month)

	Window	Entire Day (Argus)	Window % of Total
LLS	0	446,920	0%
WTI Diff to CMA	26,425	378,445	7%
Mars	5,418	185,252	3%
WTS	1,000	154,706	1%
WTI Midland	3,000	138,470	2%
HLS	1,000	100,032	1%
WTI P-Plus	1,000	88,802	1%
Eugene Island	0	40,044	0%
Poseidon	0	73,857	0%
SGC	0	22,100	0%
Bonito	0	9,140	0%
	37,843	1,637,768	2.31%

Source: Argus (2007)

One response to such a criticism is that if some market participants think that prices in the window are not reflecting accurately the price of an oil barrel at the margin, then those participants should enter the

[39] Platts (2010 b), Platts Oil Pricing and MOC Methodology Explained, *The McGraw Hill Companies*, June.
[40] Argus Global Markets (2007), Liquidity and Diversity Prevail, 24 September, p. 15.
[41] There are other markets, such as Asian products which would show in contrast very high % figures for Platts 'window' trades. Ultimately market participants decide upon which and whose pricing system and by implication, methodology, they wish to use. However, once a critical mass of players is using one in a market or series of markets, it is difficult and expensive to make a switch.

window and exert their influence on the price. However, in some markets, there might be barriers to entry preventing such an adjustment mechanism from taking place. For instance, in the context of Dubai, Binks (2005) argues that 'participation (in the window) requires knowledgeable and experienced trading staff. And many of the national oil companies that represent end-users in Asia are not allowed to participate in speculative trading. For the same reason, Middle East producers will not participate in the partials market. Even independent commercial buyers without these restraints in Asia feel reluctant to participate in the partials trade out of concern that doing so could threaten their relations with Middle Eastern producers'.[42] It is important to note that while some barriers such as having experienced and professional staff and qualified companies with the necessary logistics to execute physical trades can be considered as 'natural barriers', others barriers arise due to policy and strategic choices which limit the trading activity in the window to a small group of what so called 'professionals'.[43]

Market participants are under no legal or regulatory obligation to report their deals to PRAs or any other body for that matter. Whether participants decide to share information depend on their willingness, their reporting policies, and their interest in doing so. In the US, the system is voluntary, but one potential interpretation of the Sarbanes-Oxley legislation is that companies must report all or nothing, and cannot 'selectively' disclose information.[44] Many companies have reporting policies that only bind them to report deals that take place at a certain time of day, or in certain regional markets. In some markets such as the US, confidentiality concerns dictate that some PRAs do not publish the names of the counterparties to a deal. To ensure enough reporting takes place, PRAs such as Argus sign confidentiality agreements to facilitate deal reporting in the US though companies may have the incentive to report prices without such agreements. Since market participants have different interests and different positions, some traders may have the incentive to manipulate prices by feeding false information to reporters though there have been regulatory efforts to limit such behaviour. In the US, the Commodity Futures Trading Commission (CFTC)[45], the Federal Energy Regulatory Commission (FERC), and the Federal Trade Commission (FTC)[46] have passed regulations that prohibit false reporting. In the EU, the Market Abuse Directive is

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[42] Some interviewees also pointed to the high subscription cost involved in the entry of E-window, by which Platts is assessing larger number of markets.

[43] One interviewee considers this aspect as necessary otherwise enlarging the base of participants may create logistical and serious performance issues, including safety issues.

[44] Initially a law/regulation was passed in 2000 by the SECURITIES AND EXCHANGE COMMISSION (SEC) known as Regulation FD (Fair Disclosure). This came out of and expands upon the Insider Trading law framework and pertains to equities reporting. Sarbanes-Oxley Act expanded on this regulation. The Act deals with voluntary reporting areas. The obligation is stated that should you volunteer to report information, the obligation is to report that information fully. However, companies are not required to report trades to the PRAs. Lobo and Zhou (2006) investigated the change in managerial discretion over financial reporting following the Sarbanes-Oxley Act and find an increase in conservatism in financial reporting.

[45] On November 3, 2010, the CFTC and the Securities and Exchange Commission (SEC) proposed rules under the new anti-manipulation and anti-fraud provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act. One of the proposed rules states that, "It shall be unlawful for any person, directly or indirectly, in connection with any swap, or contract of sale of any commodity in interstate commerce… to intentionally or recklessly:….. make, or attempt to make, any untrue or misleading statement of a material fact or to omit to state a material fact necessary in order to make the statements made not untrue or misleading…. deliver or cause to be delivered….by any means of communication whatsoever, a false or misleading or inaccurate report concerning crop or market information or conditions that affect or tend to affect the price of any commodity in interstate commerce, knowing, or acting in reckless disregard of the fact that such report is false, misleading or inaccurate. Source: http://www.cftc.gov/ucm/groups/public/@lrfederalregister/documents/file/2010-27541a.pdf

[46] The Energy Independence and Security Act (Energy Act) signed into law December 19, 2007, gives the Federal Trade Commission (FTC) new authority to police "market manipulation" and "false reporting" in the petroleum industry joining the Federal Energy Regulatory Commission (FERC) and the U.S. Commodity Futures Trading Commission (CFTC) in this role. In section 812, the FTC is given the authority to act against false reporting in the petroleum industry. FTC's authority however is limited to the false reporting of wholesale transactions and those "to

also meant to perform a similar role, though its impact on price reporting is not yet clear. As discussed above, Platts relies on a more structured system for gathering information. However traders can undertake some anomalous deals in the Platts window by accepting high offers or underselling by delivering into low bids in an attempt to influence the assessed price. The losses made by such transactions can be more than compensated by entering into other contracts such as swaps. Thus, PRAs must ensure that the information received is correct and accurate and that deals done in the window are genuine, otherwise the whole price discovery process will be undermined. For instance, Platts will not knowingly publish any bid or offer that is not within the market range. In addition, when offers are lifted or bids are hit, there is a secondary process to ensure that there is no gapping and if such gapping is detected to ensure that price assessment process is not affected by it. There are also other mechanisms to avoid the influence of non-repeatable deals.

In a liquid market, false reporting can be less of a problem as reporters could observe concluded deals and confirm the information they obtain from both parties. At the same time, reporters will make use of the regular flow of information originating from the futures and OTC markets. In contrast, in illiquid markets, a small number of reported deals or a few bids and offers can heavily influence the price assessment process. In days when reporters cannot observe active buyers, sellers or transactions to determine the price or simply when such deals do not exist, [47] PRAs rely on a variety of sources of information sources or market talk to make 'intelligent assessments'.[48] In such circumstances, the reporter will look at bids and offers from other markets, draw comparisons with similar crudes but with higher trading activity, analyse forward curves, survey market participants' opinions, and assess spread across markets to reach a price assessment. In fact, in some instances, as in illiquid markets, the price assessment could be more accurate in the absence of transactions, if these transactions were intended to manipulate the oil price.

In some instances, a PRA can retrospectively correct previously unidentified assessment errors. There are some instances in which traders may dispute the assessed price reached by a PRA. There is no evidence to suggest that this problem is widespread, but from time to time these disputes filter into media reports. For instance, in 29 April 2010, Platts assessed the value of the June and July cash BFOE spread at minus $0.68 a barrel. Some brokers in the market claimed that Platts assessment of the differential is inaccurate. Based on information from the futures market and the EFP, these brokers claimed that the value of the differential should have been minus $0.94 a barrel.[49] Regardless of which value is more accurate, what is important to note that if such disputes over price assessments ever arise there is no supervisory or regulatory authority which would look into these claims and counter-claims.

In order to safeguard the price assessment process, PRA seek to verify the accuracy of the information they receive and when they are unable to do so they retain the right to exclude data and information. In this way, they guard against false data distorting their assessments. They also undertake many procedures, both within their own organisations as well as in relation to outside participants. For instance, Platts has control on the parties that can participate in the window. The companies behind every bid and offer must be clearly identified with a track record of operational and financial performance and be recognisable in the market. Trading is closely monitored and those participants that fail to meet editorial standards and/or

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a Federal Department or agency." It remain unclear if the Energy Act encompasses the reporting of false or misleading information publicly into the market or to private organizations or PRAs.

[47] It should be noted that when this is the case, companies who sign contracts linked to PRA prices tend not to use pricing centres that are illiquid. They know that no matter how well the PRA does their job the price may be volatile or unresponsive. In many cases, the PRA chooses not to assess a crude or product because the market is too illiquid, or there are insufficient parameters available to make an assessment based on correlative data points.

[48] Intelligent assessment refers to the process of assessing prices in illiquid markets where transactions are not observable to reporters.

[49] Paddy Gourlay "Dated Brent Assessment Sparks Calls For Methodology Change", Dow Jones Newswires, 30 April 2010

make spurious offers and bids are expelled from the window.[50] Concluded transactions between parties are sometimes subject to verification by the various price reporting agencies; spurious deals are excluded from the assessment process. PRAs may request documentation for concluded deals such as contract documentation or other supporting materials such as loading and inspection documents.[51]

Another important dimension is compliance procedures within PRAs. The accuracy of the price assessment will depend primarily on the policies, procedures and training put in place by the PRA. Such procedures are needed to ensure both internal and external independence and to ascertain that reporters are following the same rules, reporting procedures and methodology as set out by the RPA. All the regulations and compliance procedures are designed and enforced internally without being subject to governments' regulations or supervisory oversight. However, in theory, the incentive to self-regulate is very strong. Any reputational damage due to error of design, fraud, use of insider information, or a market perception that PRAs are herded by one party would imply a loss of confidence and would eventually lead to their demise. If PRAs produce regularly inaccurate prices, they will cease to exist because their subscribers will shift to another service.[52]

[50] Nevertheless, concerns still arise that such procedures will not stop companies from using the Platts window as a way of executing a wash trade, or trading only to set the index on index-related deals done earlier in the day. Platts cannot track every deal down to the contract level and ask for documentary bona fides.

[51] It is highly unlikely however that a PRA requesting this information would always receive it, and certainly not in a timely enough manner to have any impact on price assessments on a given day.

[52] One anonymous interviewee noted that in theory this may be true in a competitive environment but not in the case of oil PRAs where the market is characterised by almost a duopoly.

5. The Brent Market and Its Layers

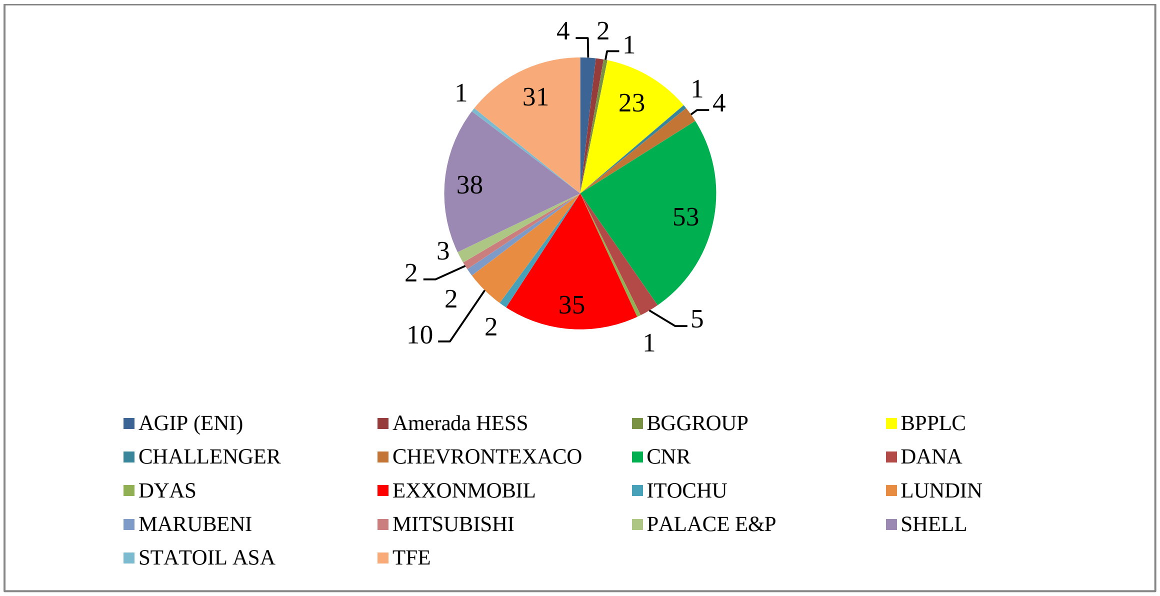
The Brent market in the North Sea assumes a central stage in the current oil pricing system. The prices generated in the Brent complex constitute the main price benchmarks on the basis of which 70 percent of international trade in oil is directly or indirectly priced. In the early 1980s, the Brent market only consisted of the 'spot' market (known as Dated Brent) and the informal forward physical market. Since that time, the Brent market has grown in complexity and is currently made up of a large number of layers including a highly liquid futures and swaps markets in which a variety of financial instruments are actively traded by a wide range of players. As noted by Horsnell (2000), the Brent market was not pre-designed and grew more complex according to the needs of market participants.

A number of special features favoured the choice of Brent as a benchmark. The geographic location of the North Sea which is close to the refining centres in Europe and the US gives it an advantage over other basins. Brent is waterborne crude and is transferred by tankers to European refiners or, when arbitrage allows, across the Atlantic Ocean to the US. The introduction of tax regulations on the UK North Sea in 1979 provided oil companies with the incentive to trade and re-trade their output in the spot market which gave rise to an actively-traded spot market in Brent.[53] Furthermore, in the mid 1980s, the volume of production of the Brent system was quite large (around 885,000 b/d in 1986) which ensured enough physical liquidity for trading. But similar bases of physical liquidity could also be found in other regions of the world, especially in Gulf countries which constitute the largest physical base in the crude oil markets. Thus, the volume of production, although important, is not the determining factor for a crude oil to emerge as an international benchmark. An important determinant is the legal, tax, and regulatory regime operating around any particular benchmark. Brent has the UK government overseeing it and a robust legal regime. Horsnell and Mabro (1993) identify additional determinants, the most important of which is ownership diversification. The commodity underlying the forward/futures contracts should be available from a wide range of sellers. Monopoly of production increases the likelihood of squeezes and manipulation, increasing in turn the risk exposure of buyers and traders who would be reluctant to enter the market in the first place (Newbery, 1984). Most countries in OPEC are single sellers and hence OPEC crudes did not and still do not satisfy this criterion of ownership diversification. Monopoly of production also prevented the development of a complex market structure in other markets with a larger physical base such as Mexico. This is in contrast to the Brent market which has always been characterised by a large number of companies with entitlement to the production of Brent (see Figure 6). The widening of the definition of the benchmark to include other crude streams over the years has reinforced this aspect and resulted in an even higher degree of ownership diversification. Another important aspect is the degree of concentration in the physical delivery infrastructure. Here the degree of concentration is much higher. For instance, the Forties Pipeline System (FPS) which collects oil and gas liquids from over 50 fields through a complex set of pipelines is 100% BP-owned.[54]

[53] See Argus (2010), Argus Guide to Crude and Oil Products Markets, January.

[54] BP Website: https://www.icmmed0ty.com/fps/content/brochure/brochure.asp?sectionid=1

Figure 6: Brent Production by Company (cargoes per year), 2007



Source: Bossley, L. (2007), Brent: A User's Guide to the Future of the World Price Marker, London: CEAG, p.83.

The Physical Base of North Sea

Crude oil in the North Sea consists of a wide variety of grades which include Brent, Ninian, Forties, Oseberg, Ekofisk, Flotta, and Statfjord just to mention few. In the early stages of the current oil pricing system, Brent acted as a representative for North Sea crude oil and price reporting agencies relied on the trading activity in this grade to identify the price of the benchmark. The Brent is a mixture of oil produced from separate fields and collected through a main pipeline system to the terminal at Sullom Voe in the Shetland Islands, UK. From the mid 1980s, the production of Brent started to decline, falling from 885,000 b/d in 1986 to 366,000 b/d in 1990 (see Table 4 below). Low physical production caused distortions, manipulation, and squeezes leading the Brent price to disconnect from the rest of grades with far-reaching effects.[55] To avoid potential distortions and squeezes, the Brent system was comingled with Ninian in 1990 leading to the creation of a new grade known as the Brent Blend while Ninian ceased to trade as a separate crude stream. The co-mingling of the Brent and the Ninian systems alleviated the problem of declining production level with the combined production reaching 856,000 b/d in 1992, as shown in the table below. Thereafter, however, the production of Brent Blend started to decline, falling to around 400 thousand b/d in 2001. In terms of cargoes, this represented around 20 per month, or less than one cargo per day.

Table 4: Oil Production By Brent and Ninian System (Thousand Barrels/Day)

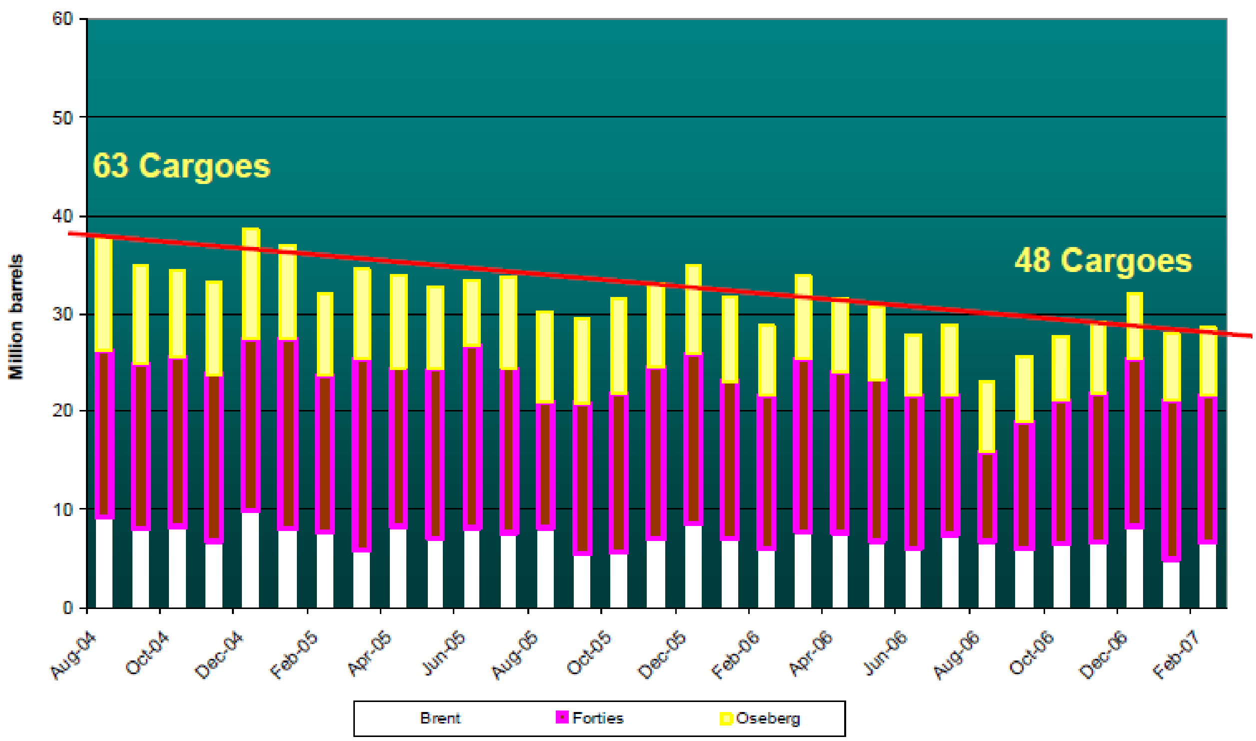
	1986	1987	1988	1989	1990(a)	1990(b)	1990	1991	1992
Brent System	885	791	734	503	450	320	396	450	547
Ninian System	346	302	373	374	366	345	357	324	309
Total Blend	885	791	734	503	450	665	540	773	856

Notes:
(a) January 1 to July 31 1990 before comingling
(b) August 1 to December 31 1990 after co-mingling
Source: Horsnell and Mabro (2003)

[55] See for Instance, Liz Bossley (2003), Battling Benchmark Distortions", Petroleum Economist, April.

In July 2002, Platts broadened its definition of the benchmark Dated Brent to include Forties (UK North Sea) and Oseberg (Norway) for assessment purposes and as deliverable grades in the Brent Forward contract. Forties is a mixture of oil produced from separate fields and collected by pipeline to the terminal in Hound Point in the UK. Oseberg is a mixture of oil produced from various Norwegian fields and collected to the Sture terminal in Norway. The new benchmark was known as Brent-Forties-Oseberg (BFO). The inclusion of these two grades increased the production volume of the benchmark. It also resulted in the distribution of cargoes over a wider range of companies with none having a dominant position. However, as seen from the graph below, the production of BFO started its decline, falling from 63 cargoes a month in August 2004 to around 48 cargoes in the first months of 2007. In early 2007, BFO production amounted to less than 30 million barrels a month, distributed over more than 55 companies.

Figure 7: Falling output of BFO



Source: Joel Hanley, Assessing the Benchmarks, Platts Presentation, January 31, 2008.

In 2007, a new grade, Ekofisk, was added to the complex which led to the creation of the current benchmark known as BFOE, though it is still commonly referred to as Brent or North Sea. Ekofisk is a mixture of crude oil produced from different North Sea fields and is transported to the Teesside terminal in the UK. The bulk of BFOE output is traded on the spot market or transferred within integrated oil companies where only about one out of seven BFOE cargoes is sold on long-term basis.[56] This feature combined with the highly diversified ownership gave rise to an active trading activity around BFOE. The inclusion of this new stream increased the physical base of the benchmark to around 45 million barrels a month in early 2007 but since then it has been in gradual decline. Production of BFOE is expected to decline to less than 1 million b/d by 2012. As noted by Platts (2010a:3), further changes to the benchmarks can't be ruled out, especially 'if production of the key grades is deemed too low or if their qualities were to deviate significantly from the norm'. In fact such a change might occur sooner rather

[56] Argus (2010), Argus Guide to Crude and Oil Products Markers, January.

than later. A recent article warns that 'unless the contract is enlarged, it faces the risk of serial squeezes and distortions'.[57]

Given that these various grades are not of similar quality as shown in Table 5 below, the widening of the definition of the North Sea benchmarks has implications on the price assessment process. In particular, the start-up of the Buzzard field in 2007 increased the viscosity and the sulfur content of Forties Blend making Forties the least valuable among the various crudes in the BFOE benchmark. Since any of the four varieties can be delivered against a BFOE contract, sellers often tend to deliver the cheapest grade and hence it is Forties that sets the price for the BFOE benchmark.[58] This problem becomes more acute during periods when other fields in the Forties system are shut down for maintenance. As a result of including the Buzzard stream, Platts had to introduce a quality 'de-escalator' in July 2007 which applies for deliveries above the base standard of 0.60% sulfur: the higher the sulfur content, the bigger the discount that the seller should give. Currently, a de-escalator of 60 cents/barrel applies for every 0.10 per cent of sulfur specified above the base standard. Prior to this 'innovation', the market was not sure on how to deal with the sulfur issue and in some periods in 2007 there were no trades in the Platts window.[59] This episode almost brought the physical market to a standstill with traders complaining that Platts changes to its pricing assessment process had paralysed the market.[60]

Table 5: API and Sulfur Content of BFOE Crudes

	Forties Before Buzzard	Buzzard	Brent	Oseberg	Ekofisk
API	44.1	32.6	38.1	37.7	37.5
Sulfur Content wt.	0.19	1.44	0.42	0.23	0.23

Source: Bossley, L. (2007), Brent: A User's guide to the Future of the World Price Marker, London: CEAG, Table 5.

The Layers and Financial Instruments of the Brent Market

Around the Brent/BFOE physical benchmark, a number of layers and instruments have emerged, the most important of which are: Brent Forwards, Contract for Differences (CFDs), Exchange for Physicals (EFPs), and Brent futures, Brent options and swaps. Some of the instruments such as futures are traded on regulated exchanges such as ICE while others such as swaps are traded bilaterally over-the-counter (OTC). Nevertheless, these layers are highly inter-linked and are essential for the risk management and the price discovery functions.

Data Issues

In the Brent complex, data about the different layers such as the volume of trading, the number of concluded deals, the composition of participants and the degree of concentration are not publicly available. Oil PRAs are under no legal obligation to report or publish such data although oil trading data gathered by PRAs are made available to subscribers at a price. This section relies on data provided by Argus. While this is one of the best sources for data on the Brent complex, the data suffers from some limitations. There are no legal or regulatory obligations on participants in the Brent market to report their deals and thus the coverage depends on the willingness of participants to provide information to the oil

[57] Kemp, J. (2011), Falling Output Imperils Brent Benchmark, Reuters, 19 January 2011.

[58] For instance on May 25 2010, Forties was assessed at $67.57-67.59, Oseberg at $68.49-68.52, Ekofisk at $68.29-68.32, and Brent at $68.02-68.05 by Platts. The BFOE or North Sea Light was assessed at 67.57-67.59, the same as the assessment of the value of Forties.

[59] FT.com/Alphaville (2010), 'Brent's Got Its Problems Too', September 2010.

[60] Reuters (1997), Platts to modify new oil price system after turmoil, 19 June.

pricing reporting agencies. This has a number of important implications. First, since there is OTC trade that goes unreported, the volume of market activity reported by Argus is likely to be a fraction of the total volume of trade conducted in the various Brent layers. Nevertheless, it is representative of the market activity and hence any proportions based on this 'sample' such as the relative sizes of OTC markets and the shares held by different companies are likely to represent fairly accurately the structure of the market. Second, when analysing trends over a period of time, changes in statistics related to liquidity or to the number of reported deals may reflect changes in coverage by the price reporting agency rather than underlying changes in the statistic. Third, other problems arise when making comparisons across the different Brent layers. For instance, in the futures markets, every deal is reported and the size of the contract is 1000 barrels. In some layers such as Dated Brent and 21 Day BFOE, players can end up with a ship full of crude which limits the attractiveness of these markets to a large number of participants. Hence, one should be careful when comparing across markets as although these are all part of the Brent complex, they differ in nature and function. Furthermore, the nature of trading can be different across markets. For instance, in Dated Brent and 21 Day BFOE, trade in outright differentials or spreads is the norm though 21 Day BFOE can also trade on a fixed price basis. In the futures and options, trade in differentials also constitutes an important component of trade between months. This involves buying a contract in one month (say a June contract) and selling a contract in another month (say a July contract). In terms of reporting, each of the two legs of the transaction is reported as an outright deal. Thus, any comparisons across markets should adjust for the volume of such trade in spreads.

The Forward Brent

The Forward Brent is one of the first layers to emerge in the Brent complex. The forward Brent is also referred to as 21-day Brent, 21-day BFOE or simply as paper Brent. Forward Brent is a forward contract that specifies the delivery month but not the particular date at which the cargo will be loaded. Forward Brent price is often quoted for three months ahead. For instance, on 25th May, the Forward Brent is reported for the months of June, July and August. These price quotations represent the value of a cargo of physical delivery in the month specified by the contract.

In order to understand the nature of the Forward Brent market, it is important to look at the precursor of the 21-day Brent, the 15-day Brent market. The incentive for oil companies to engage in tax spinning through the forward market was the main factor responsible for the emergence of the forward 15-Day Brent market (Mabro *et al.* 1986; Horsnell and Mabro, 1993; Bacon, 1986). The valuation of oil for UK fiscal purposes was based on market prices. In an arm's-length transaction, market prices were obtained from the realised prices on the deal.[61] If oil was merely transferred within a vertically integrated system, then the fiscal authorities would assign an assessed price to the transaction based on the prices of 'contemporary and comparable' arm's-length deals. Until 1984, these followed the official British National Oil Corporation (BNOC) price. Because of the differential rates of taxation between upstream and downstream with the tax rate being lower in the latter, the impact of the fiscal regime was not neutral and affected a vertically integrated oil company's decision to sell or retain crude oil.[62] When the spot price was lower than the official BNOC price, integrated oil companies had the incentive to sell their own crude arm's-length and buy the crude needed for their own refineries from the market. When the spot price was higher than the assessed price, oil companies had the incentive to keep the oil for use in their own refineries. In doing so, the oil companies would achieve higher after-tax profits. After the abolition of BNOC, the assessment process of transactions within the firm became more complex. The market value of non-arm's-length transactions was based on the average price of contracts (spot and forward)

[61] The fiscal authorities specified a number of conditions before a contract could qualify as arm's length including the condition that the deal is not made back to back.
[62] Tax spinning refers to this situation in which for fiscal reasons oil companies would resort to buying and selling crude oil in the market though it would have been more convenient and cheaper to internalize the transaction (Horsnell and Mabro, 2003:63).

preceding the deal. This encouraged oil companies whether vertically integrated or not to engage in tax spinning through the forward market.[63]

Although tax spinning continued to provide a motive for trading in these markets, its importance has declined as tighter regulations, introduced later in 1987, made it more difficult and much less predictable. But by then, the 15-day forward market was well established and expanding fast as various market participants including oil companies, traders, and refiners began to trade actively in this market for risk management and speculative purposes.

The 15-day Brent market largely evolved in response to the peculiar nature of the delivery schedule of Brent. Companies producing crude oil in the Brent system nominated their preferred date for loading at the relevant month by the 5th of the preceding month. The loading programme was then organised and finalised by the 15th of the preceding month. Until the schedule was completed, producers did not know the exact date when their crude oil would be available for delivery. But these producers may have already entered into forward contracts in which they agreed to sell their cargoes for forward delivery for a specified price. Under the 15-day contract, sellers were required to give the buyer of the forward contract at least 15 days notice of the first date of a three-day loading window. Under the 21-day BFOE contract, the seller is required to provide the purchaser at least 21 days notice as to when the cargo will be loaded.

For instance, assume that on the 10th of May, the producer enters into a 21-day BFOE contract for delivery in July. On that day the seller does not know when its crude oil will be available for delivery. In the month prior to delivery, i.e. in June, the loading schedule is published. The seller is given a 3-day window between the 22nd and 24th of July in which he can load the oil into tankers. The seller has to nominate the buyer at the latest by the 1st of July which is the period required to give the buyer notice to take delivery. Depending on the market conditions at the time of nomination, the original buyer may or may not want actual possession of the cargo. In fact, it is likely that the original cargo purchaser has already sold another 21-day contract (i.e. booked out his position)[64], in which case he must give notice to the new buyer to take the cargo at least 21 days in advance. In this way, the 21-day BFOE contract can transfer hands between buyers and sellers through a daisy chain of notices until a purchaser is ready to accept delivery or the 21-day period expires and/or the holder of the forward can no longer provide notice for any more buyers.[65] Once the notice period is expired, the oil to be loaded on a specific date is classified and traded as Dated Brent. For instance, on the 5th of July, the cargo is traded as Dated Brent where the delivery date is known (17-19 days ahead).

The 21-day BFOE can be either cash-settled by traders offsetting their position in the daisy chain or can be physically settled. However, only a small percentage of forward contracts are physically settled. Figure 8 below shows the average daily traded volume on a monthly basis and the number of participants in the 21-day BFOE market. As seen from this graph, the number of players during one month is small between four and 12 players. Furthermore, the traded volume is low not exceeding 600,000 b/d. Between September 2007 and August 2008, liquidity in the forward market declined at a fast rate reaching the very low level of less than 50,000 b/d in August 2008. However, liquidity recovered in 2009 and 2010 with daily average liquidity in the first half of 2010 reaching more than 400,000 b/d. This is less than one cargo a day compared to around 30 cargoes a day at the heyday of the 15-day Brent market during the late 1980s. Features such as the large size of the cargoes, clocking and the daisy chain games make trading in forward Brent a risky proposition and the domain of few players. This has pushed the industry to find

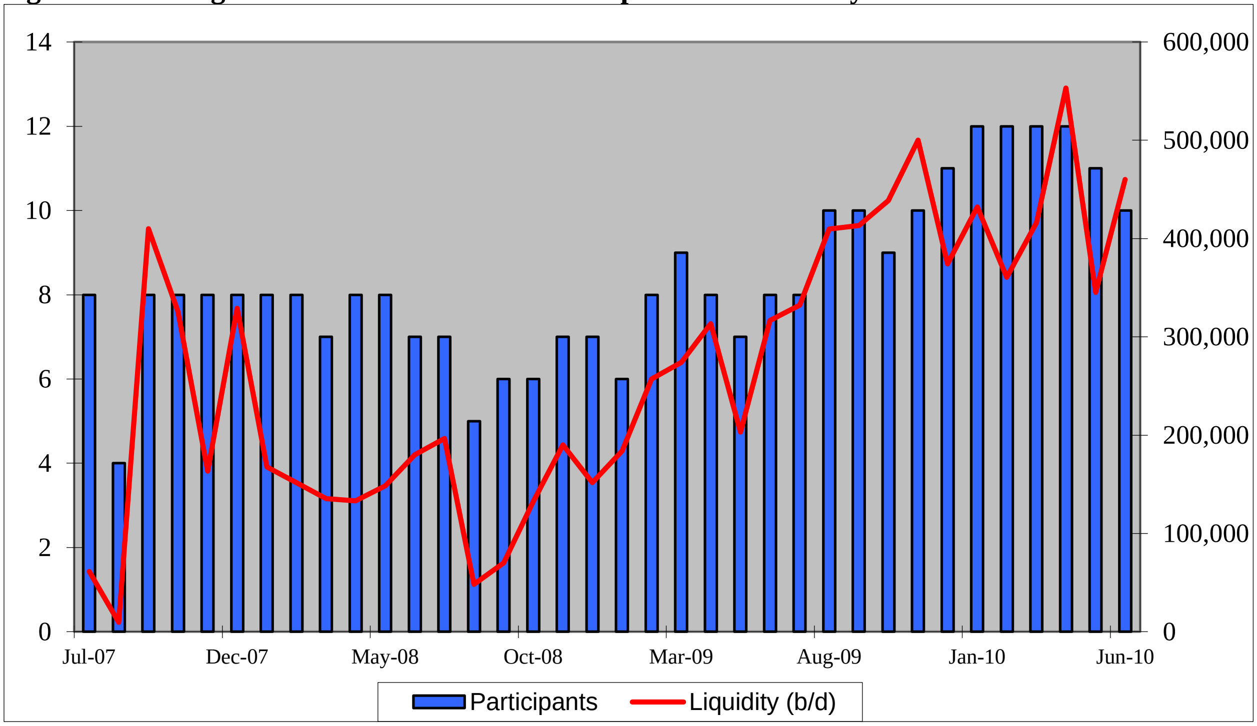
[63] For details on how tax spinning can be transacted through trading in the forward market, see (Horsnell and Mabro, 1993, Chapter 6 and Bacon, 1986).

[64] Book out is used to describe the process whereby a daisy chain of forward transactions having been identified (such as creating a circle in which A sells to B who sells to C who sells to A) is closed by financial settlements of price differences rather than physical delivery.

[65] In trading terms, the holder of the contract who is unable to require another purchaser to take delivery is said to have been 'five-o'clocked'.

alternative ways to manage their risk without trading in the forward market, which can explain the decline in its trading activity. The futures market has provided such an alternative. Given the central role that the forward market assumes in the Brent complex, ensuring that there is enough liquidity in the 21-day BFOE is crucial to the price discovery process. This is especially the case as the settlement mechanism of the ICE futures Brent contract is based on trading activity in the forward Brent market.

Figure 8: Trading Volume and Number of Participants in the 21-Day BFOE Market



Source: Argus

There are few participants in the 21-day BFOE. Unlike the futures market, the forward contract involves trading in 600,000 barrels which is beyond the capability of many small players and hence the composition is not as diverse as in the futures market. Table 6 below shows the various participants in the Brent forward market and their total volume of trading during the period 2007 and 2010 (September). On the sales side, the main players include oil companies with equity interest such as BP, Shell, Conoco Phillips and Total and some of their trading arms such as Totals' TOTSA and physical traders such as Vitol, Phibro and Mercuria. On the purchase side, these same companies also dominate the trading activity. For instance, in 2010, Shell was the most important seller and the third important purchaser while Totsa was the second important seller and the second important buyer. On the purchase side, the four top players Vitol, Mercuria, Totsa, and Shell captured more than 70% of the observed volumes by Argus. On the sales side, these companies captured more than 60% of the trading volumes in 2010. The degree of concentration varies across months and in certain months few players capture the bulk of traded volumes.

Table 6: Participants in the 21-Day BFOE Market and their Shares in Trading Volume

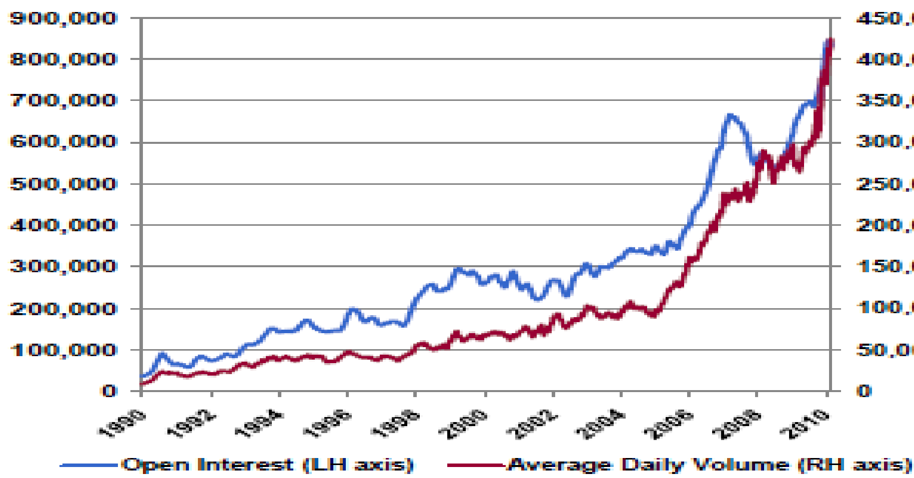
	Sales (b/d)				Purchases (b/d)			
	2007	**2008**	**2009**	**2010**	**2007**	**2008**	**2009**	**2010**
Arcadia	0	0	0	0	485	0	0	0
BP	23,786	3,005	13,699	29,545	25,243	273	10,959	12,662
Chevron	0	273	274	0	0	273	0	0
ConocoPhillips	18,447	11,749	12,329	32,143	6,311	5,464	12,329	29,545
Glencore	0	0	274	0	0	546	548	0
Hess	0	0	9,315	37,338	0	0	10,137	20,779
Hetco	0	0	822	7,143	0	0	1,096	974
Mercuria	12,136	12,842	64,658	79,545	13,107	24,863	54,247	89,286
Morgan Stanley	0	0	274	28,896	0	0	3,014	19,805
Noble	0	0	548	6,494	0	0	822	5,844
Phibro	46,602	19,126	25,479	23,377	36,408	23,770	36,164	14,935
Sempra	15,534	18,306	13,151	8,766	18,447	19,672	13,699	7,792
Shell	34,951	62,022	125,205	91,883	46,117	32,787	73,151	75,000
StatoilHydro	0	273	0	0	0	0	0	0
Total	0	0	0	649	0	0	0	2,273
Totsa	31,068	16,667	53,425	62,987	61,650	28,962	108,767	83,442
Trafigura	0	0	0	16,234	0	0	0	10,714
unknown	0	273	0	0	0	273	0	0
Vitol	68,447	12,842	48,219	56,818	43,204	20,492	42,740	108,766
	252,978	**159,386**	**369,681**	**483,828**	**252,979**	**159,383**	**369,682**	**483,827**

The Brent Futures Market

The Brent futures contract was initially launched on the International Petroleum Exchange (IPE), now known as the InterContinental Exchange (ICE), in London in June 1988 after a number of failed attempts. As in the case of other futures contracts, the ICE Brent Futures contract's terms and conditions are highly standardised, which facilitate trading in these contracts. The futures contract specifies 1,000 barrels of Brent crude oil for delivery in a specified time in the future. The contract expires at the end of the settlement period on the business day immediately preceding the 15th day of the contract month, if such 15th day is a business day. For instance, a December contract will expire on the 15th of November if it is a business day. The ICE Brent Crude futures contract is cash settled with an option of delivery through Exchange for Physicals (EFP). The trading takes place through an electronic exchange which matches bids and offers between anonymous parties.

The ICE Brent crude oil futures market has grown dramatically in the last two decades; in 2010, the daily average volume traded exceeded 400,000 contracts or 400 million barrels, more than five times the volume of global oil production (see Figure 9 below). Initially, the features of the Brent futures contract attracted small players but after few years of its development, it started attracting large physical players who enter the market to manage their risk, hedge their positions as well as bet on oil price movements. The futures market has also attracted a wide range of financial players including swap dealers, pension funds, hedge funds, index investors, and technical traders.

Figure 9: Average Daily Volume and Open Interest of ICE Brent Futures Contract



Source: ICE

An interesting feature of the Brent futures contract is that at expiry it cash settles against the ICE Brent Futures Index, also known as the Brent Index which is calculated on the basis of transactions in the forward Brent market. In other words, unlike other futures contracts whose price converges to spot price at expiry, the Brent futures contract converges to the price of forward Brent. Specifically, the Brent index is calculated on the basis of weighted average of first-month and second-month cargo trades in the 21-day BFOE plus or minus average of the spread trades between first and second months as reported by oil price reporting agencies. At expiry, the Brent futures contract relies on the forward market for cash settlement. Thus, the effectiveness of the futures market in the role of price discovery relies on the liquidity of the forward market which as discussed previously is quite variable and concentrated in the hand of few players. This feature of the Brent futures contract is the result of historical events where the development of the forward market preceded that of the futures market plus the fact that no producer in the North Sea would back a physically delivered contract. This meant that for any Brent futures contract to succeed, it has to be strongly linked to the forward market.

The Exchange for Physicals

Although the Brent futures contract is not physically settled, the Exchange for Physicals (EFPs) market allows participants to swap a futures position (a financial position) with a physical one. Specifically, by executing an EFP, a party can convert a futures position into Brent Forward or a 21-day BFOE cargo.[66] EFPs are carried outside the exchange and at a price agreed between the parties. The way the EFP works is straightforward. Party A with a futures position sells the futures contract and buys the physical commodity. His counterparty B buys the futures position from A and sells the physical commodity to A. Through this process, A is able to gain physical exposure to the underlying commodity while B has swapped his physical exposure for a financial one. Such trades can be transacted at any prices agreed between A and B and are often different from the price prevailing in the futures market. EFPs are often quoted as differentials to the Brent futures price but usually do not exceed it by more than a few cents.

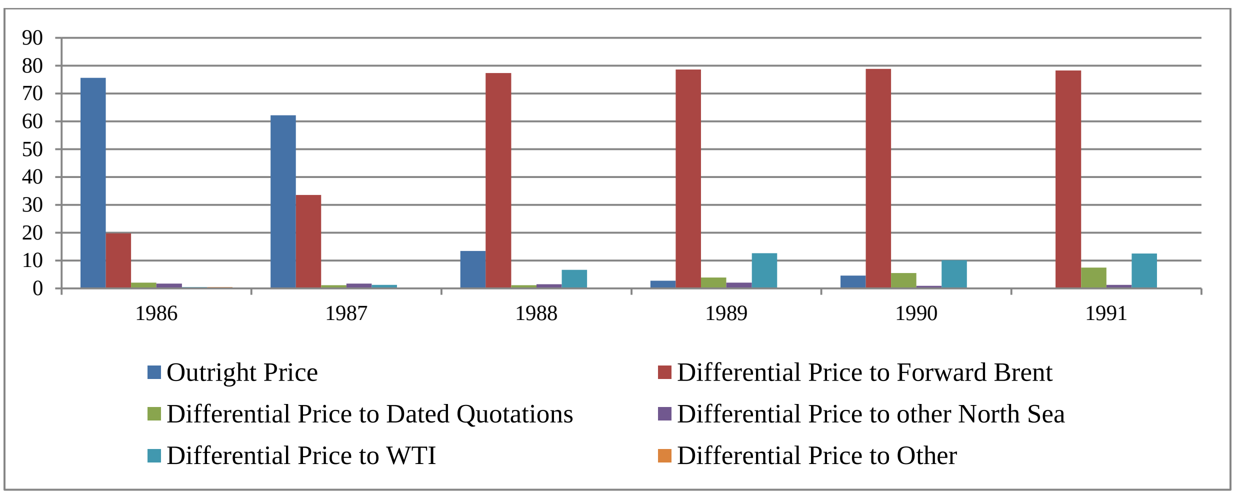
[66] It is important to note that Brent EFPs are not qualitatively equivalent to physically delivered contracts such as WTI. EFP is optional while for WTI contract, the trader has no choice but to close the position or make or take delivery.

Parties need to notify the Exchange about their agreement so it can close A's position and open B's position. Thus, the importance of EFP is that it provides a link between the futures market and the physical dimension of the Brent market. As discussed below, in periods of thin trading activity in the forward Brent market, the EFP provides the necessary link to identify the price of forward Brent.

The Dated Brent/BFOE

Dated Brent/BFOE, also known as Dated North Sea Light (Platts) or Argus North Sea Dated refers to the sale of cargo with a specific loading slot. It is often referred to as the spot market of Brent.[67] A spot transaction is often thought of as a transaction in which oil is bought or sold at a price negotiated at the time of agreement and for immediate delivery. However, Dated BFOE contracts contain an important element of forwardness as traders rarely deal with cargoes bought and sold for immediate delivery. Instead, cargoes are sold and bought for delivery for at least 10 days ahead. To reflect this fact, the price of Dated BFOE is quoted for delivery 10 to 21 days ahead. For instance, on 25th May, the price of Dated BFOE reflects the price of delivery for the period between the 4th of June and the 15th of June (11 days). On 26th May, the price of Dated BFOE rolls forward one day to cover the period between the 5th and 16th of June (11 days), and so on. This element of forwardness in Dated BFOE also implies that there is a price risk between the time when a Dated BFOE cargo is bought and the time when it is delivered. Formula pricing can mitigate part of this risk by pricing the cargo of Dated BFOE on the time of delivery or by using the average of prices around the loading date, such as three days before and after the loading date. One interesting feature of the Dated BFOE market is that very few deals are done on an outright basis. Instead, since 1988, actual deals for physical cargoes of BFOE, including Brent, are priced as a differential to forward Brent or Dated Brent/ North Sea Dated. As seen from Figure 10 below, by 1991, deals based on outright prices became negligible. Thus, while the forward Brent sets the price level, the Dated BFOE market sets the differential to the forward market. More recently, forward Brent itself is been priced as a differential to the Futures Brent.

Figure 10: Pricing basis of Dated Brent Deals (1986-1991); Percentage of Total Deals



Source: Horsnell and Mabro (1993)

The Contract for Differences (CFDs)

The Contracts for Differences (CFDs) have become an integral part of the Brent market and as discussed in detail in Box 1 provide the link between the forward Brent market and Dated BFOE. CFDs are swaps contracts which allow the buyer and seller to gain exposure to the price differential between Dated BFOE

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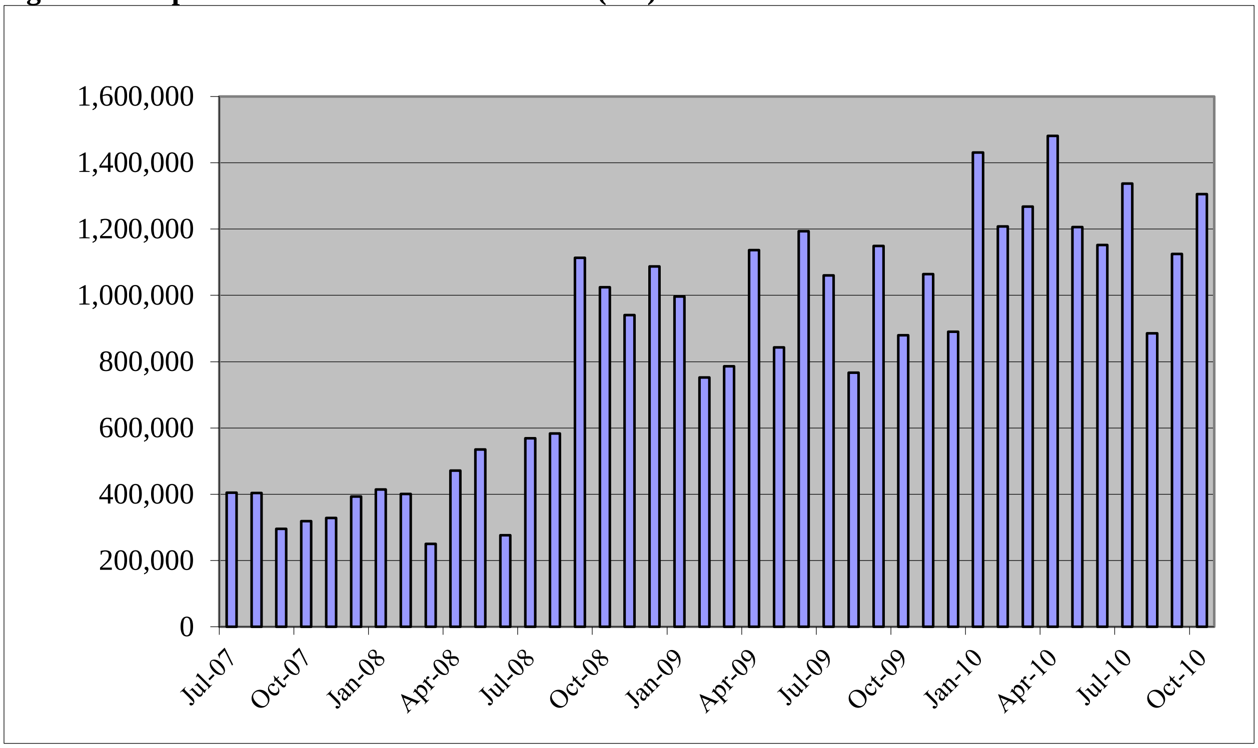
[67] It is important to note however that physical Brent or Brent/Ninian Blend trades at a differential to the Dated Brent or North Sea Dated Price.

and Forward Brent. These CFDs can be traded in Platts window or negotiated bilaterally outside the window or the exchanges. The high volatility in the above differential increased the risk exposure for physical players, pushing them to hedge using CFDs. This in turn created an important niche for market makers. Figure 11 below reports the daily volumes of traded CFDs which vary from as low as 250,000 b/d in March 2008 to as high as 1.4 million b/d in April 2010. However, these figures seem to understate the actual volume of CFD trade with some market participants indicating that the volume of traded CFDs is much higher.

Figure 11: Reported Trade on North Sea CFDs (b/d)



Source: Argus

The players in this market are quite diverse and include a large number of companies as seen in the table below. On the sales side, the dominant players are equity producers such as BP, Chevron, Shell, Statoil; banks such as Morgan Stanley and physical traders such as Vitol, Mercuria and Phibro. On the buying side, these companies are also dominant. There are many companies that occasionally enter the market and trade small volumes mainly for hedging purposes.

Table 7: Participants in the CFD Market and their Trading Volumes

	Sales (b/d)				Purchases (b/d)			
	2007	**2008**	**2009**	**2010**	**2007**	**2008**	**2009**	**2010**
Addax	0	0	411	0	0	0	740	812
Arcadia	23,301	4,918	4,658	14,448	6,553	10,109	6,575	17,208
Astra	0	0	0	0	2,427	1,298	0	0
BNP Paribas	0	0	548	5,519	0	0	2,192	4,221
BP	26,214	55,601	74,085	76,948	43,083	37,432	24,397	75,010
Cargill	485	1,913	411	0	485	4,918	274	1,136
Chevron	17,233	26,093	70,699	84,659	43,811	47,541	53,863	73,195
Chinaoil	0	0	0	0	0	0	1,233	0

ConocoPhillips	485	10,410	23,041	33,766	728	24,863	28,630	60,065
Glencore	1,456	1,940	14,219	24,968	485	4,372	9,863	26,299
Gunvor	0	7,240	13,151	3,571	1,942	5,464	3,836	1,299
Hess	971	273	2,192	22,240	0	0	2,192	17,532
Hetco	0	0	0	3,571	0	0	1,096	974
IPC	0	273	2,055	325	0	1,481	3,068	1,786
Iplom	0	0	548	0	0	1,093	548	1,136
Itochu	0	546	7,671	7,253	0	6,126	11,041	10,844
JP Morgan	9,223	11,380	9,153	7,792	1,456	29,358	54,973	14,935
Koch	33,010	36,284	23,556	3,247	11,165	37,205	34,849	32,305
Lukoil	971	13,798	28,559	24,513	485	7,049	20,411	21,753
Maesfield	0	0	1,644	1,136	0	0	0	1,623
Marathon Oil	0	0	0	0	11,408	9,699	548	6,494
Masefield	0	273	1,233	3,247	0	3,825	685	0
Mercuria	34,345	46,809	59,726	79,471	31,311	68,415	99,841	117,156
Merrill Lynch	1,942	4,781	1,918	1,299	7,646	4,645	0	0
Mitsubishi	0	0	0	0	0	0	3,014	0
Mitsui	0	273	0	0	1,456	546	0	0
Morgan Stanley	20,388	24,317	57,882	100,487	20,146	17,760	51,238	88,377
Murphy	0	0	0	0	0	410	0	0
Natixis	0	0	42,033	19,968	0	0	36,849	27,110
Neste	971	4,372	2,740	0	0	3,005	822	1,623
Nexen	1,942	4,577	4,003	6,951	2,427	2,691	5,189	11,685
Noble	0	0	822	14,286	0	0	548	8,442
OMV	1,485	0	14,562	28,545	0	5,787	36,995	48,880
ORL	0	1,093	0	0	0	2,186	0	0
Petraco	0	820	1,644	974	0	1,735	2,192	0
Petrodiamond	0	0	0	1,948	0	0	822	0
Petroplus	5,583	3,825	1,918	0	1,942	0	1,644	0
Phibro	20,146	48,656	68,923	82,867	36,772	52,117	34,400	50,487
Pioneer	0	0	0	0	0	0	137	0
Plains	0	2,732	0	0	0	0	2,466	1,299
Preem	0	0	685	0	0	0	3,562	0
Sempra	971	7,978	9,644	2,273	4,854	15,929	15,616	2,922
Shell	47,694	131,929	132,079	149,221	52,699	39,727	83,995	129,545
Sinochem	0	0	0	1,136	0	273	603	974
Sinopec	0	0	1,932	2,597	0	0	2,800	1,867
Socar	0	0	0	25,000	0	0	0	9,091
Sonatrach	0	0	274	974	0	0	7,260	8,279
Standard Bank	0	0	932	5,575	0	0	548	5,195
Statoil	6,796	2,186	8,630	108,224	4,369	273	8,630	118,130
StatoilHydro	14,563	77,945	59,233	0	6,796	54,781	61,863	325
Totsa	19,782	23,087	45,260	25,974	14,078	46,325	47,397	60,575
Trafigura	971	16,940	29,315	27,955	3,641	13,798	28,877	32,649
Unipec	8,738	7,377	4,521	8,955	0	12,432	29,170	11,578
Valero	1,456	546	1,096	0	9,951	14,208	19,726	54,545
Veba	0	0	0	0	0	1,093	0	0
Vitol	36,044	58,579	132,060	245,692	15,049	49,795	112,447	98,214
	339173	641772	961675	1259585	339172	641772	961674	1259585

Source: Argus

OTC Derivatives

In addition to the above layers, a whole set of financial instruments that link to the Brent complex are currently traded over the counter (OTC). These OTC contracts are customised and until recently have been negotiated bilaterally between parties either face-to-face or through brokers. However, as the use of OTC became more widespread, OTC contracts became more standardised and part of the OTC activity has shifted to electronic OTC exchanges. Furthermore, after being matched, counterparties can use the clearing facilities of exchanges such as ICE and the CME Group. The landscape has become less benign in a number of ways for bilateral uncleared OTC, and so there has been a shift toward clearing OTC contracts except for those with either impeccable credit/ unimpeachable credit lines, or those who simply cannot afford the cash flow/cash flow volatility of a cleared environment (such as airlines). IOSCO (2010) reports that market participants conduct 55% of their trades in financial oil (crude oil and refined products) using exchange-traded instruments and hence are subject to clearing. The remaining part of the business is conducted through OTC. A large part of this OTC trade is now being cleared where 19% of survey participants' trades are being cleared. Only 27% of the total volume traded remains un-cleared.[68] The growing similarity between more standardised OTC and exchange-traded instruments has raised the issue of disparity in supervision and oversight between markets and is at the heart of current plans to strengthen the regulation of commodity derivatives markets. Exchange clearing of OTC has aided their transparency already, as they make available daily settlement figures to those clearing the instruments.

The large variety of OTC instruments and the limited information on these instruments precludes an extensive analysis of OTC markets. ICE lists more than 30 financial contracts (for crude oil alone) that are cleared on their exchange. These contracts are used primarily for hedging, but also for speculative purposes and are an integral part of the Brent complex. Using these instruments one can hedge between the various layers such as between Dated Brent and futures Brent or between further away markets such as Dubai and futures Brent or between Dated Brent and WTI. One important and active market discussed above is CFDs. Another active swaps market is the Brent Dated-to-Frontline (DFL) market which trades the difference between Platts' Dated Brent assessments and the ICE first month futures contract. Another related but less liquid market has emerged which trades the difference between Dated Brent and the daily trade-weighted Brent average reported by the ICE. Through these customised contracts, traders can establish a series of inter-linkages not only between the different layers of the Brent market, but also between Brent and the different benchmarks and hence are likely to influence the price formation and price discovery processes.

BOX 1: CFD Explained with an Example

To explain the rationale behind CFDs and how it works, it would be useful to provide a simple example, but based on real data. A refiner bought a cargo of BFOE on 19th March 19 for loading on 21st-23rd of April. The refiner has accepted to buy the cargo at the Dated Brent price *averaged over five days* around the loading date (i.e. 19th-23rd April). The refiner observes that the current value of Dated Brent is $77.88. He is concerned that by the time of loading the price of Dated Brent could increase: he would like to hedge his risk. In principle, he could use the April Forward contract to hedge the risk. However, this hedge is far from perfect because there is the risk that the price of the April Forward may not follow the movements of Dated Brent at the time of loading. This risk, referred to as the basis risk, constitutes the main rationale for CFDs.

To hedge the basis risk, the refiner could buy (a) a second-month Forward contract (i.e. a May contract in our example) and (b) CFDs for the week of 19th-23rd April. The price for the Forward May contract on the

[68] These figures however should be treated with caution and some market participants have indicated very different numbers. The fact remains that the size of the OTC market is not known and less so the percentage of OTC that goes to clearance.

19th of March stood at $79.53 while the CFD for the week 19th-23rd April was at -$0.57. By buying the second-month forward contract and CFDs, the refiner is able to lock the price of his cargo at $79.53.

So how does the hedge work? Somewhere between 19th-23rd April (say 22nd of April) i.e. when the cargo is being loaded, the refiner sells the Forward May contract. On the 22nd of April, the BFOE May contract settled at a price of $84.78. Thus, the refiner has made a profit on his forward position of $5.25: he bought the forward contract at $79.53 and sold it at $84.78. What about the gain and losses on the CFD position? The easiest way to think of a CFD is that it is a swap in which the refinery agrees to receive the price of Dated Brent and agrees to pay the Forward price. Assuming that the refinery unwinds his CFD over the week, we can calculate the net gain or loss on the CDF as illustrated in the Table below.

CFD Explained

Date	Dated Brent	BFOE MAY	Loss/Gain CFD	Loss/Gain CFD
19/04/2010	83.19	83.53	0.2×(83.19-83.53)	-0.068
20/04/2010	84.74	84.86	0.2×(84.74-84.86)	-0.024
21/04/2010	84.47	84.62	0.2×(84.47-84.62)	-0.03
22/04/2010	84.64	84.78	0.2×(84.64-84.78)	-0.028
23/04/2010	86.49	86.43	0.2×(86.49-86.43)	0.012
Total Loss/Gain				-0.138

The refinery's final position as of 23rd of April 2010 is shown in the table below. The high price paid for the cargo in April has been compensated for by the gain in forward position. In this example, the refiner has lost on his CFD position.[69]

Example of CFD (continued)

	Refinery's Final Position (23rd of April 2010)
Price Paid for the Cargo (Average Dated Brent over the period April 19-April 23)	84.706
Gain on Forward Position	5.25
Loss on CFD	-0.138
	79.594

Notice from the above example that the CFD allows us to derive in March the Forward price for Dated Brent for the week 19th-23rd April. The Forward Dated Brent is simply the CFD plus the second month forward i.e.

$$\text{Forward Dated Brent} = \text{CFD} + \text{Second Month Forward Brent}$$

Thus, the CFD is *not* the price differential between the current price of Dated Brent and the Forward Brent Contract. It is rather the difference between the Dated Brent at some stated point in the future and

[69] Notice that the refinery's position is not perfectly hedged. In the above example, the May Brent is sold in one day and is not being closed over the five day period. The average of the BFOE May over 19th-23rd April period is $84.884 in which case the refiner would have made a profit of $5.314 on his forward position. This will yield $79.53, the price of the original hedge.

the Second Month Forward Brent.[70] Since CFDs are reported for eight weeks ahead, it is possible to derive the price of Forward Brent for eight weeks ahead. Platts refers to these forward prices as BFOE swaps. These prices provide the vital link between the 21-Day BFOE and Dated Brent and are central for the price discovery process in the Brent market.

The Process of Oil Price Identification in the Brent Market

Trades in the levels of the oil price rarely take place in the various layers that link the physical dimension of Brent with the Brent futures. Instead, oil price reporting agencies such as Platts and Argus infer or identify the oil price level for a wide variety of crudes by exploiting the linkages and the information derived from the various layers of the Brent market. The process starts by identifying the price of *Forward Brent/BFOE*. The price quotation will represent the value of a cargo for physical delivery within the month specified by the contract. These price quotations are produced daily for three months ahead. Oil price reporting agencies derive the forward Brent price from deals reported to them by brokers and traders in the forward market (Argus) or based on deals conducted in the window (in the case of Platts). However, movements on ICE futures Brent market can also be factored into the assessment. Furthermore, spread values and EFPs could also be considered. Thus, oil reporting agencies often rely on information from the futures market to derive the price of Forward Brent, especially at times when the forward market is suffering from thin liquidity and is dominated by few deals.

The contract that links the futures Brent and the forward Brent is the Exchange for Physicals (EFPs). Oil PRAs have increasingly relied on EFPs to derive the Forward Brent price. These are often priced as differential to the Brent futures price. The Brent futures prices and the EFP for a particular month allow the identification of the forward Brent price for that month. The formula can be as simple as adding the value of EFP in a particular month (say July) as assessed by the oil reporting agency or generated by the futures exchanges to the closing price of the July contract in the futures market i.e.

Forward Brent (July) = Futures Price (July) + EFP (July)

Having derived the price level for Forward Brent, the next step is to derive the price of Dated Brent. As discussed above, the price of Dated Brent is important to the oil price discovery process as it is considered as the spot market for Brent and should closely reflect the physical conditions in the oil market. As in the case of Forward Brent however, the price of Dated Brent needs to be identified with the help of another layer: the OTC market of Contract for Differences (CFDs). The CFD allows us to derive the Forward Dated Brent using the following formula

Forward Dated Brent = CFD plus Second Month Forward

Given that CFDs are reported for eight weeks ahead,[71] the Forward Dated Brent can be derived for 8 weeks into future which give us the 'Forward Date Brent Curve'. For each of the weeks, the price of Dated Brent/BFOE swaps is reported.

Based on the derived Forward Dated Brent Curve, it is possible to calculate the average of the Forward Dated Brent from day 10 to day 21. These days are the ones assessed for physical delivery. For instance, if today is 21st May, the 10-21 day cargoes refer to 6th -17th June. Argus reports this as the 'Anticipated Dated Average for the 10-21 days Forward' while Platts uses the term 'North Sea Dated Strip' or the 'Forward Dated Brent'. These are reported as an outright price.

Since BFOE is comprised of four different crudes, these blends of individual crudes often trade as differentials to the 10-21 average of the Forward Dated Brent or North Sea Dated Strip. Based on an

[70] An alternative way to understand the equation above is to go through the above example. By buying a Forward contract and CFDs, the trader is able to lock today the price for Dated Brent for delivery at a certain time in the future.

[71] In essence CFDs can be traded for any week that is needed to trade, but are only reported for 8-weeks ahead.

assessment of these differentials through MOC process or observed deals, it is possible to calculate the price of Dated Brent/BFOE or Dated North Sea Light (Platts) or Argus North Sea Dated (Argus) for the day.[72] Specifically, the price of Dated Brent will settle on the most competitive crude among the BFOE combination which is usually Forties.[73]

The above discussion implies that during the last three decades the Brent market has evolved into a complex structure consisting of set of interlinked markets which lie at the heart of the international oil pricing system. The Brent market is multi-layered with the various layers being strongly interconnected by the process of arbitrage. Thus when referring to Brent, it is important to specify what Brent is being referred to: Dated Brent, 21-Day Brent, Brent futures, Brent CFDs or even to Brent altogether as the continuous decline in the physical liquidity meant the Brent Blend has become less important in the North Sea physical complex. These layers and links are central for the price discovery process as identifying the oil price relies heavily on information derived from the financial layers. The implications of these linkages on the oil price formation process are discussed in details in Section 8.

[72] Alternatively, one can take a simple average of the four crudes which would result in Platts' North Sea Basket.

[73] As an example, on May 25, 2010, North Sea Dated Strip was priced at 68.13-68.14. This value was derived from the Dated Brent Swap based on the average of 10- 21 window. Each of the four crudes is priced as a differential to the forward Dated Brent. On May 25, 2010, Brent was priced at -0.11/-0.09; Forties at -0.56/-0.55, Oseberg at 0.36/0.38 and Ekofisk at 0.16/0.18. These differentials are obtained from concluded deals and failing that on bids and offers. Since Forties is the most competitive crude, the Dated Brent/BFOE is obtained by applying the Forties differential. Specifically Dated Brent/BFOE=North Sea Dated Strip (68.13-68.14) + Differential (-0.56/-0.55) = 67.57-67.59.

6. The US Benchmarks

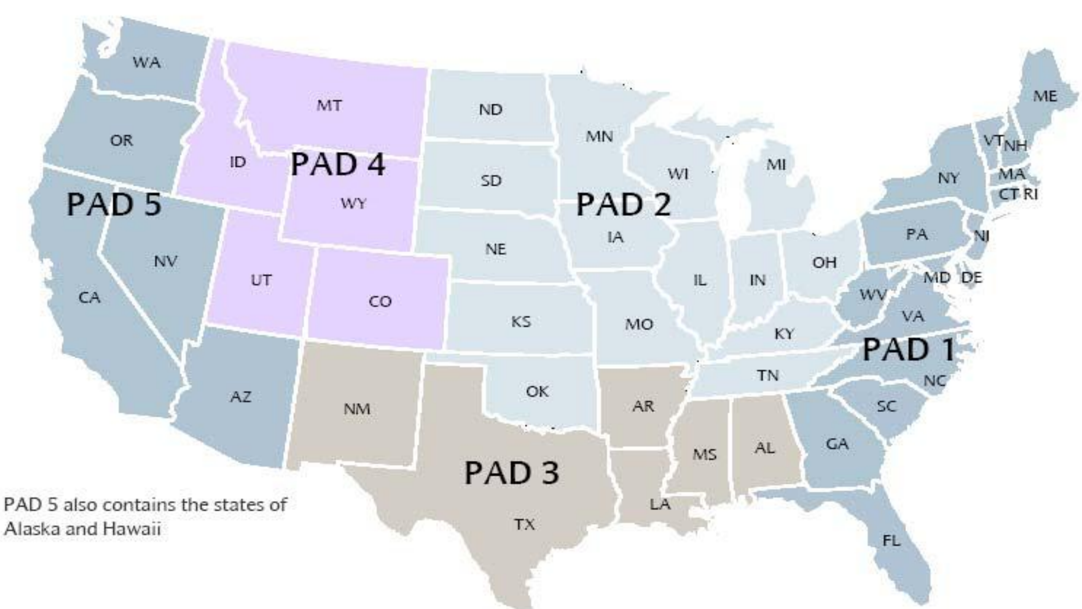
West Texas Intermediate (WTI) is the main benchmark used for pricing oil imports into the US, the world's largest oil consumer. More crude oil is priced-off the Brent complex, but the Light Sweet Crude Oil Futures Contract, which is based on WTI,[74] is one of the most actively traded commodity futures contract. While WTI is the most widely known US crude stream, other crude streams exist alongside WTI. One such is the Light Louisiana Sweet (LLS) crude which has become the local benchmark for sweet crude in the US Gulf Coast. Other important streams include the US-Gulf Coast Sour and Medium crudes such as Mars and Poseidon (produced offshore Louisiana) and Southern Green Canyon (produced offshore Texas). On the basis of transactions in these three crude streams, Argus derives ASCI. Platts publishes a similar index known as America's Crude Marker which incorporates the value of the four sour grades: Mars, Poseidon, SGC and Thunder Horse (produced offshore Louisiana).

The Physical Base for US Benchmarks

The US constitutes the largest oil market in the world. In 2009, US consumption accounted for almost a quarter of global consumption. The US is also an important producer, its production reaching 5.3 million b/d or about 5% of the global production in 2009. The US is also an important refining centre with an operable refining capacity exceeding 17 million b/d in 2009.

Central to understanding the physical base of US benchmarks is the 'Petroleum Allocation for Defense Districts' (PADD) regional definitions. The US is divided into five regions or PADDs as seen from the map below. The most important district in terms of production is PADD III where in 2009 it produced more than 3 million b/d out of total US's production of 5.3 million b/d (see Table 8 below). PADD III is also the most important refining centre in the US, with refining operable capacity of around 8.5 million b/d accounting for almost half of operable refining capacity in the US (see Table 9).

Figure 12: US PADDS



Source: EIA

[74] The Light Sweet Crude Oil Futures contract is also referred to as the WTI futures contract.

Table 8: US Oil Production by District

	2004	2005	2006	2007	2008	2009
U.S.	5,419	5,178	5,102	5,064	4,950	5,361
PADD 1 (East Coast)	**19**	**23**	**22**	**21**	**21**	**18**
PADD 2 (Midwest)	**435**	**443**	**458**	**470**	**538**	**591**
Kansas	93	93	98	100	108	108
North Dakota	85	98	109	123	172	218
Oklahoma	171	170	172	167	175	184
PADD 3 Gulf Coast)	**3,016**	**2,804**	**2,838**	**2,828**	**2,699**	**3,121**
Louisiana	228	207	202	210	199	189
Texas	1,073	1,062	1,088	1,087	1,087	1,106
Federal Offshore (PADD 3)	1,453	1,282	1,299	1,277	1,152	1,559
PADD 4 (Rocky Mountain)	**309**	**340**	**357**	**361**	**357**	**357**
Wyoming	141	141	145	148	145	141
PADD 5 (West Coast)	**1,640**	**1,569**	**1,426**	**1,385**	**1,336**	**1,274**
Alaska	908	864	741	722	683	645
North Slope	886	845	724	707	670	638
California	656	631	612	594	586	567

Source: EIA Website

Table 9: Operable Refining Capacity by District

	2004	**2005**	**2006**	**2007**	**2008**	**2009**
U.S.	**16,974**	**17,196**	**17,385**	**17,450**	**17,607**	**17,678**
PADD 1	1,736	1,717	1,713	1,720	1,722	1,723
PADD 2	3,526	3,569	3,583	3,595	3,670	3,672
PADD 3	7,967	8,159	8,318	8,349	8,416	8,440
PADD 4	582	589	596	598	605	622
PADD 5	3,164	3,162	3,175	3,187	3,195	3,222

Source: EIA Website

While PADD III constitutes the major production and refining centre in the US, PADD II assumes special importance as it is the main centre for crude oil storage and the delivery point at the expiration of the

Light Sweet Crude Oil Futures contract. Cushing, Oklahoma located in PADD II is a gathering hub with large storage facilities: an estimated operable crude storage capacity of 45.9 million barrels and nameplate storage capacity of 55 million barrels.[75] PADD II itself can be divided into two sub regions: the Midcontinent and the Midwest (Purvin and Gertz, 2010). Cushing is located in the Midcontinent. It collects crude oil from Texas, surrounding Oklahoma and other imported crude. It links to major refineries centres both in the Midcontinent, the Midwest (PADD II) and PADD III through a complex set of pipelines.[76] Historically, the refineries in the Midcontinent relied on domestic crude for their runs. However, with the decline in domestic production, refineries in the Midcontinent increased their reliance on foreign imports and Canadian crude delivered into Cushing and the broader region. A similar picture also emerged for the Midwest where historically it has relied heavily on domestic production. However, given the decline in production and its proximity to Canada, Canadian crude started to rise in importance displacing domestic production and imports from outside Canada, a trend which is likely to continue. As seen in Table 10 below, in 2009 Canadian imports accounted for 90% of total oil imports into PADD II. In contrast, refineries in PADD III have access to a wide variety of crude oil with offshore imports from OPEC constituting the bulk of total imports.

Table 10: Total Imports by District from OPEC and Canada (Million b/d)

	2004	2005	2006	2007	2008	2009
PADD1 (Total)	**1,549**	**1,605**	**1,497**	**1,495**	**1,421**	**1,244**
OPEC	764	893	844	936	807	587
Canada	197	215	210	263	260	215
PADD 2 (Total)	**1,584**	**1,516**	**1,514**	**1,497**	**1,517**	**1,407**
OPEC	370	323	300	345	297	154
Canada	1,054	1,039	1,150	1,125	1,176	1,222
PADD 3 (Total)	**5,768**	**5,676**	**5,656**	**5,611**	**5,375**	**5,090**
OPEC	3,448	3,131	3,147	3,533	3,521	3,013
Canada	18	20	59	96	106	126
PADD 4 (Total)	**260**	**271**	**278**	**278**	**264**	**232**
Canada	260	271	278	278	264	232
PADD 5 (Total)	**926**	**1,057**	**1,173**	**1,149**	**1,206**	**1,040**
OPEC	460	469	493	574	790	601
Canada	87	88	105	126	151	148

Source: EIA

Although a wide variety of crude oils is produced in the US, WTI assumes special importance in the global oil and financial markets since WTI underlies the Light Sweet Crude Oil futures contract, one of the largest traded commodity futures contract. It should be noted however though that trade around Cushing, and a forward market around that trade, existed prior to the establishment of the futures market.

[75] Storage operators keep 41pc of tank space for their own use and lease 59pc to third parties. Plains and Magellan plan to add a combined 8.25mn bl of new storage at Cushing next year. See Argus Global Markets (2010), EIA Reveals Cushing Tank, 6 December

[76] For details see Purvin and Gertz, 2010.

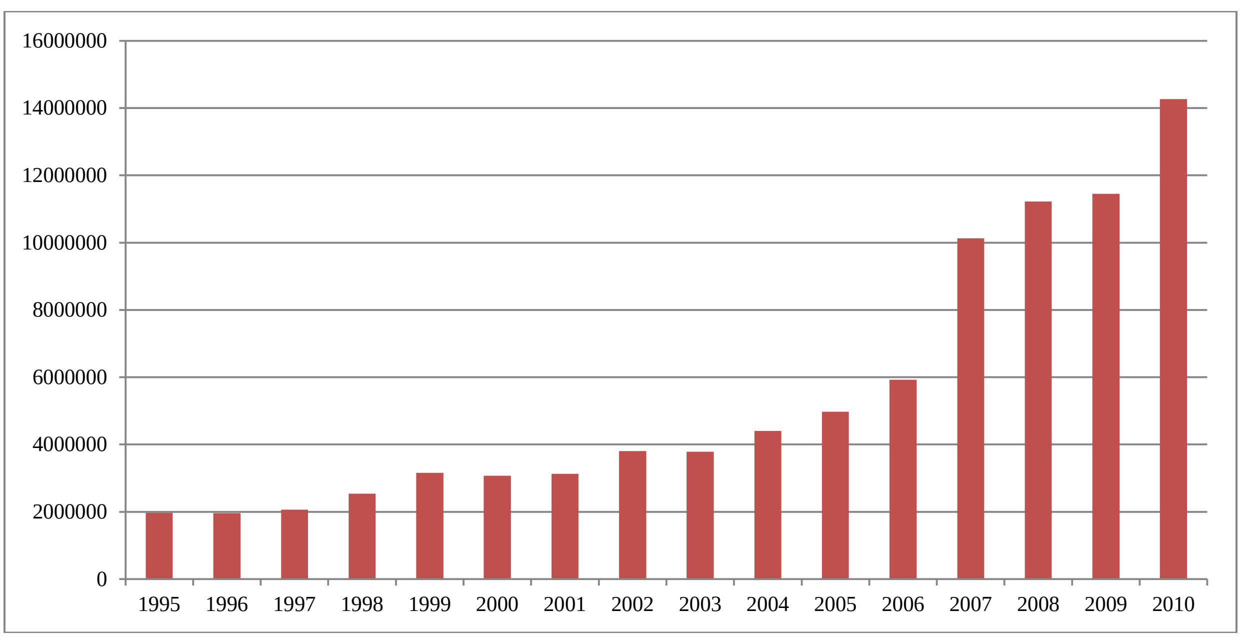
That forward market existed in parallel to the futures market through the late 80s and early 90s. However, unlike the Brent market, as futures volumes grew, it eventually eliminated the need for the forward market. This forward market was knows as the 'WTI Cash Market'. Its last vestige exists now only in the 3 days between futures expiry and pipeline scheduling on the 25th of each month, discussed in details below.

WTI is a blend of crude oil produced in the fields of Texas, New Mexico, Oklahoma and Kansas. It is a pipeline crude and deliveries are made at the end of the pipeline system in Cushing, Oklahoma. As in the case of Brent, the WTI market is also characterised by a large number of independent producers who sell their crude oil to large number of gatherers. However, unlike Brent which is waterborne crude, WTI is pipeline crude and thus is subject to problems of logistical and storage bottlenecks. Brent is exportable which makes it more flexible and more responsive to trading conditions in the Western Hemisphere. Furthermore, as discussed later in this section, WTI can show serious dislocations from other markets in some occasions, reducing its attractiveness as a global benchmark or even as a US benchmark.

The Layers and Financial Instruments of WTI

Very few layers emerged around the WTI, the most important of which are the futures and option contract and OTC derivatives. The Light Sweet Crude Oil Futures contract has been trading on the New York Mercantile Exchange (now part of the CME Group) since 1983. Figure 13 below shows the monthly averages of volumes traded of the Light Sweet Crude Oil Futures Contract for the last 15 years. Between 1995 and 2010 (January-September), the monthly volumes of traded contracts grew at an average annual rate of 15%. As seen from the graph below, the increase in traded volume between 2006 and 2010 has been phenomenal with the average annual growth rate during the period 2007 and 2010 reaching 27%. In 2010, the monthly average volume exceeded 14 million contracts or 14 billion barrels. On a daily basis this amounts to more than 475 million barrels of oil, around 6 times the size of the daily global oil production. Most of the trading takes place through the electronic platform (known as GLOBEX) which provides ease of access from virtually anywhere in the world almost 24 hours a day. A wide range of players are attracted to the futures market including commercial enterprises such as producers, marketers, traders as well as speculators and variety of financial investors such as institutional and index investors.

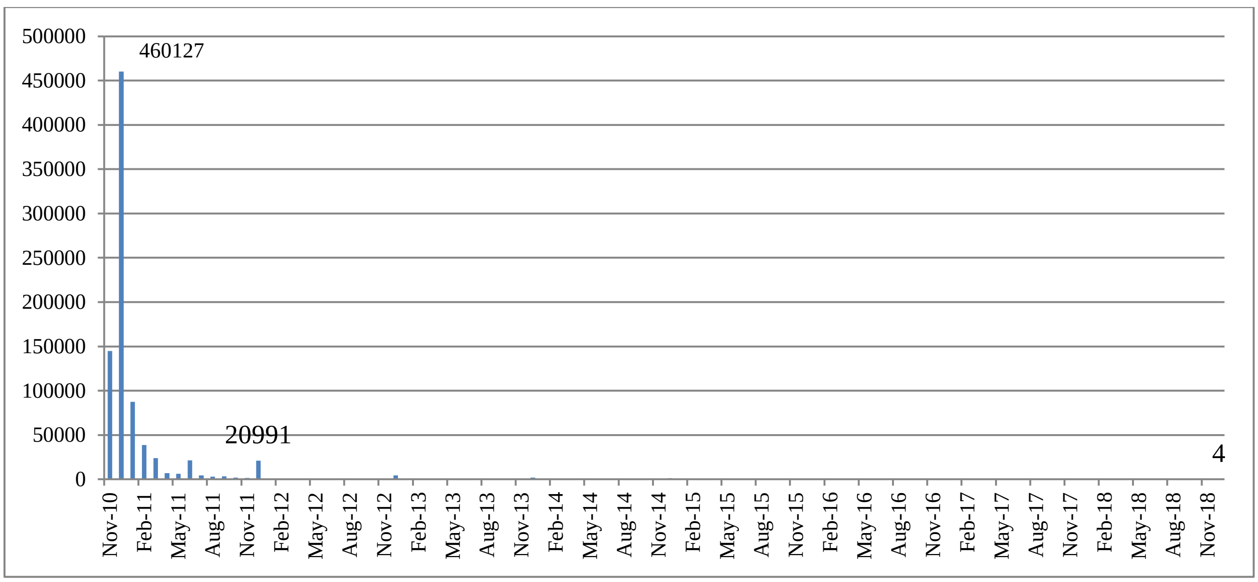
Figure 13: Monthly averages of volumes traded of the Light Sweet Crude Oil Futures Contract



Source: CME Group

Unlike the Brent futures contract (where delivery is elective via the EFP mechanism), the Light Sweet Crude Oil Futures contract is fully physically delivered for every contract left open at expiry by default. It specifies 1,000 barrels of WTI to be delivered at Cushing, Oklahoma. The contract also allows the delivery of domestic types of crude (Low Sweet Mix, New Mexican Sweet, North Texas Sweet, Oklahoma Sweet, and South Texas Sweet) and foreign types of crude (Brent Blend, Nigerian Bonny Light and Qua Iboe Norwegian Oseberg Blend and Colombian Cusiana) against the futures contract. It is important to note though that only a small percentage of the volume traded is physically settled with most of the physical settlement occurring through the EFP mechanism. EFP provides a more flexible way to arrange physical delivery as it allows traders to agree on the location, grade type, and the trading partner. Crude oil futures contracts are traded for up to nine years forward. However, liquidity tends to decline sharply for far away contracts (see Figure 14). For instance, on October 19, 2010 the bulk of the trading activity concentrated on the December 2010 contract. There is some liquidity up to one year ahead, but as we move towards the back end of the futures curve, liquidity tends to decline sharply. For instance, on October 19, 2010, the traded volume of December 2017 and December 2018 contracts stood at 33 and 4 contracts respectively.

Figure 14:Liquidity at Different Segments of the Futures Curve (October 19, 2010)



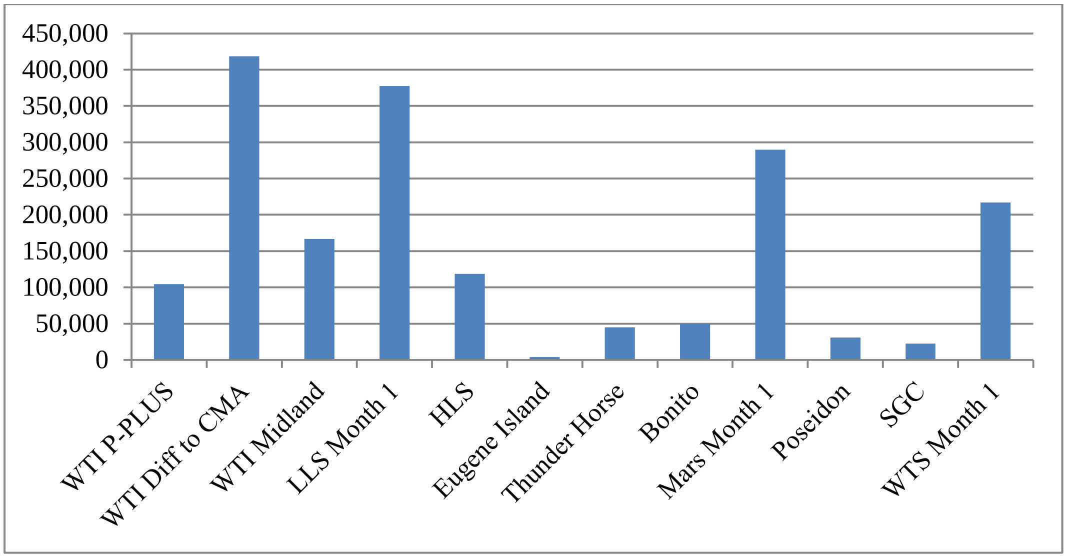
Source: CME Group Website

In addition to the futures and option contracts, a group of OTC financial instruments link to the WTI complex, allowing participants to use more customised instruments than those available in the futures market. As discussed in the case of Brent, a large fraction of OTC deals linked to WTI are using the clearing facilities of the CME Group or ICE. The CME group lists more than 90 OTC financial contracts for crude oil that are cleared on its exchange. Contracts such as the WTI-Brent (ICE) Calendar Swap Futures and the WTI Calendar Swap Futures are more customised and are traded OTC but cleared through the exchange.

The Price Discovery Process in the US Market

Unlike the Brent market, trading in the US pipeline market is of smaller volumes typically around 30,000 barrels compared to 600,000 barrels in the Brent market. Trade in small volumes has increased the diversity and number of players who find it easier to obtain the necessary credit and storage facilities to participate in the US market. Furthermore, the US market has maintained its liquidity despite the decline in physical production and consolidation within the industry. In 2009, the combined spot-market traded volume for twelve US domestic grades (for the month of April) stood at more than 1.8 mb/d[77] (see Figure 15) which is much higher than other benchmarks including BFOE, Oman and Dubai.

Figure 15: Spot Market Traded Volumes (b/d) (April 2009 Trade Month)



Source: Argus (2009), 'Argus US Crude Prices Explained', 24 September

Most of those crudes imported into the US and sold in the spot market are linked to WTI with some exceptions such as Iraq, Kuwait and Saudi Arabia's sales to the US which are linked to ASCI; some imports from West Africa and the North Sea which are linked to Dated Brent; and some Canadian East Coast crudes which also link to Dated Brent. While producers still use the 'assessed' prices of WTI in their pricing formula, those assessments are often made as a differential to the settlement price in the futures market. In other words, it is the futures market that sets the price level while 'assessed' prices by oil price reporting agencies set the differentials.

The physical delivery mechanisms complicate the price assessment process. In the futures market, trading in the current delivery month expires on the third business day prior to the twenty-fifth calendar day of the month preceding the delivery month. For instance, the March WTI futures contract expires on the 22nd of February. Under the terms of the futures contract, delivery should be made at any pipeline or storage facility in Cushing, Oklahoma and must take place no earlier than the first calendar day of the delivery month (March) and no later than the last calendar day of the delivery month (March). At expiration, three business days are needed for pipeline scheduling to organise the physical delivery in March. The three-day window between the expiration of the monthly NYMEX WTI contract and the deadline for completing the shipping arrangements (i.e. between the 22nd and 25th of February in our example) is known as the roll period. During this period, the March WTI futures contract has already expired while the spot (physical) month is still March.[78] To derive the spot price of WTI March, PRAs assess the cash roll which is the cost of rolling a contract forward into the next month without delivering on it. This transaction can also simply be a purchase/sale of current month supply valued at an EFP to next month futures. On the 26th of February, the physical front month becomes April which can then be linked to the April WTI futures contract.

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[77] Argus (2009), "Argus US Crude Prices Explained", 24 September.

[78] In our example, the physical month extends in our example from 26th January through February 25th.

Historically, a large number of independent producers used to sell their crude oil to gatherers based on WTI posting plus (P-Plus), which is the sum of the wellhead posted prices plus delivery costs into Cushing. Nowadays the P-Plus market is widely used with its sister market, the differential to Nymex Calendar Monthly Average (CMA) market. The P-Plus market used the Koch posting only as a basis up until about 3 years ago when Koch stopped publishing that. Now companies tend to transact versus the ConocoPhillips posting. The value that the differential to Postings (P-Plus) represents is the value for delivery into Cushing in the current calendar month, assuming a certain cost to move the barrels to Cushing. ConocoPhillips is known to use the Nymex settlement price, adjusted by the cost of moving the barrel to Cushing, to set the price of the posting. This way the CMA and P-Plus markets are mathematically connected and never too far out of synchronisation. The CMA market has been gaining liquidity and is increasingly being used to value prompt crude oil in the US. It is the most active market in terms of volumes of spot trade as seen from Figure 15. It is important to note that CMA is an extension to the futures market. The CMA market does not trade price levels, but often trades at a differential to the WTI futures contract settlement price. CMA and P-Plus have replaced the WTI Cash Window.[79]

Platts uses its window to assess WTI differential to CMA and other domestic crudes. While the CMA market is quite liquid with large and diverse number of players, the percentage of transactions in the Platts' window is only a small fraction of total transactions during the day.[80] In June 2007 for instance, total window trade amounted only to 4% of entire day trade observed by Argus. For all US crudes, total window trade amounted to 2.4% of all spot trade.[81] Some crude streams such as Mars show 19 days of no trade in June 2007 and prices were assessed based on bids and offers.[82] Furthermore, despite the diversity of players in the market, the degree of concentration in the window is quite high with a few players dominating the trading activity.[83] Given these concerns and the fact the CMA is priced as a differential to the price in the futures market, it is surprising that producers do not more widely use futures prices directly into their pricing formula.[84] The WTI futures contract is a physical one and the price of the futures contract converges to the spot price at the expiration of the contract. Hence, in the case of WTI, the use of the futures price instead of assessed prices in the pricing formulae would make little difference. The depth and the high liquidity of the futures market surrounding WTI and the diversity of its market participants should incentivise buyers and sellers to use the futures price in their formula pricing. In practice, there is some evidence that the front-month WTI futures price can exhibit high volatility around the expiry date in some instances, which may partly explain the preference of some traders to stick to assessed WTI prices. Furthermore, both the P-Plus and CMA are means of valuing WTI that is one month prompter than the promptest futures contract.

WTI: The Broken Benchmark?

It has been recognised that the links between the WTI benchmark and oil prices in international markets can be at times dictated by infrastructure logistics. In the past, the main logistical bottleneck has been how to get enough oil into Cushing, Oklahoma. In many instances, this resulted in dislocations with WTI rising to high levels compared to other international benchmarks such as Brent. The problem has recently been reversed. While the ability to get oil into Cushing has increased mainly through higher Canadian imports, the ability to shift this oil out of the region and to provide a relief valve for Cushing is much more constrained as the storing in Cushing is inaccessible by tanker or barges with few out-flowing

[79] The WTI Cash Window, which was/is a Platts mechanism for setting the price of WTI at 3:15 EST after the close of the Nymex at 2:30 EST, has not traded for about 3 years. It is no longer an operative index because very few companies use it for price reference.

[80] Argus Global Markets (2007), "Liquidity and Diversity Prevail", 24 September.

[81] Argus, "State of the Market Report: US Domestic Crude", Argus White Paper.

[82] Ibid.

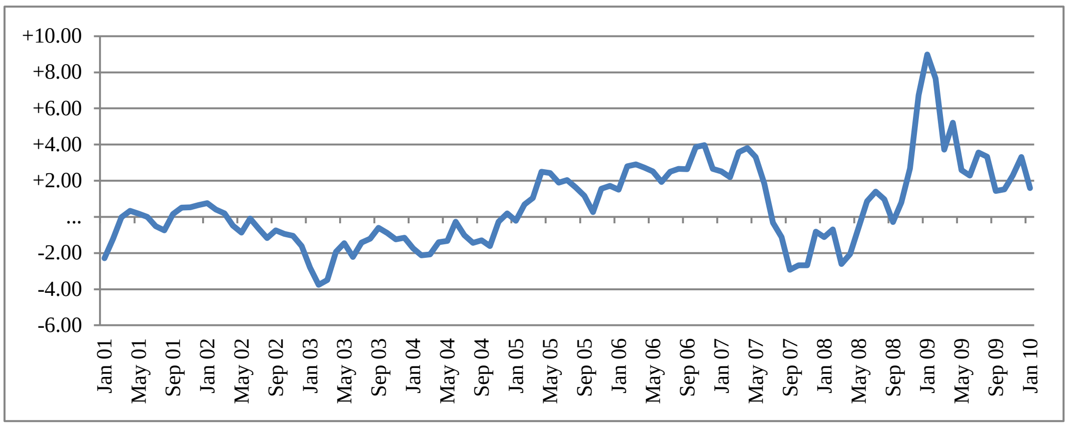
[83] Ibid.

[84] It is important to note though that many companies do use the NYMEX settlement as a pricing index.

pipelines, especially southbound towards the US Gulf major refining centre. In some occasions, this has led to a larger than expected build-up of crude oil inventories in Cushing. For instance, in 2007, due to logistical bottlenecks, there was a large build-up of inventories as a result of which the WTI price disconnected not only from the rest of the world, but also from other US regions. In 2008, the build-up of inventories in Cushing due to a deep contango and reduction in demand induced by the credit crunch caused a major dislocation of WTI from the rest of the world.

Given the major role that WTI plays in the pricing of US domestic crude, imported oil into the US and global financial markets, the price effects of such logistical bottlenecks are widespread. First, dislocations result in wide time spreads as reflected in the large differential between nearby contracts and further away contracts as seen in Figure 16 below. For instance, in January 2009, the spread between a twelve-week ahead contract and prompt WTI reached close to $8 with implications on inventory accumulation.

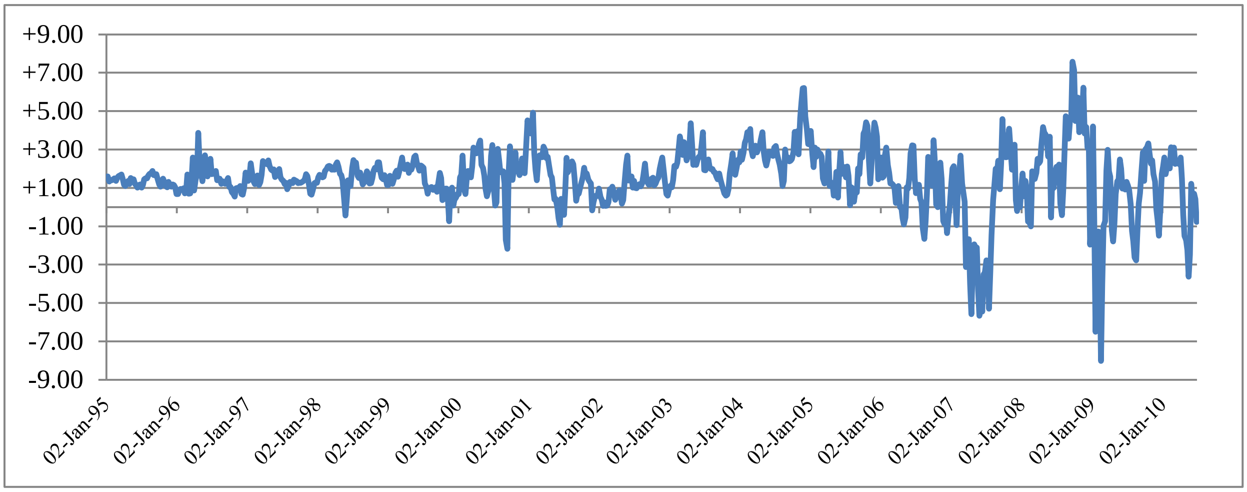
Figure 16: Spread between WTI 12-weeks Ahead and prompt WTI ($/Barrel)



Source: Oil Market Intelligence

Dislocations also have the effect of decoupling the price of WTI from that of Brent, as reflected in the large price differential between the two international benchmarks (see Figure 17). For instance, in February 2009, the differential exceeded the $8/barrel mark. Similar episodes occurred in May and June of 2007. Such behaviour in price differentials however does not imply that the WTI market is not reflecting fundamentals. On the contrary, price movements are efficiently reflecting the local supply-demand conditions in Cushing, Oklahoma. The main problem is that when local conditions become dominant, the WTI price can no longer reflect the supply-demand balance in the US or in the world and thus no longer acts as a useful international benchmark for pricing crude oil for the rest of the world. It has also become less useful as a means of pricing crude in other US regions such as the Gulf coast.

Figure 17: WTI-BRENT Price Differential ($/Barrel)



Source: Petroleum Intelligence Weekly

Most Latin American producers[85] and until recently also some Middle East producers used WTI in their pricing formula in long-term contracts. In 2010, Saudi Arabia decided to shift to an alternative index known as the Argus Sour Crude Index (ASCI) for its US sales. Kuwait and Iraq soon followed suit. ASCI is calculated on the basis of trade in three U.S. Gulf of Mexico grades: Mars, Poseidon and Southern Green Canyon. Unlike WTI and LLS which are sweet and light, the ASCI benchmark is a medium sour index. These sour crudes also do not seem to suffer from infrastructure problems and the occasional logistic bottlenecks that affect WTI, although disruptions could take place as they exposed to potential hurricanes, as Hurricanes Rita and Ivan illustrated. Their physical bases have benefited from the increased production in the Gulf of Mexico and as a result the volume of spot trade in the underlying crudes is sizeable. It is important to note that like other local US benchmarks, ASCI is linked to WTI and currently trades as differential to WTI. In a way, the 'WTI Nymex price is the fixed price basis for the index' and thus ASCI is not intended 'to replace WTI as fixed price but instead works in conjunction with other markets to provide a tool for valuing sour crude at the Gulf Coast' (Argus, 2010:3). This explains why newly listed derivatives instruments such as futures, options and over the counter (OTC) around ASCI did not gain any liquidity as most of the hedging can be done using the WTI contract.[86]

[85] Mexico's formula for sales to the USA is much more complex. It may include the price of more than one reference crude (WTI, ANS, West Texas Sour (WTS), Light Louisiana Sweet (LLS), Dated Brent and may be linked to fuel prices.

[86] Another potential reason as to why ASCI OTC has not gained volume is because the users of the Saudi/Kuwaiti/Iraqi crude are also often producers of the ASCI grades and as such they are internally hedged through their own activities.

7. The Dubai-Oman Market

Currently most cargoes from the Gulf to Asia are priced against Dubai or Oman or combination of these crudes where around 13.1 mb/d or 94% of Gulf exports destined to Asia are priced of Platts' assessment of Dubai/Oman (Leaver, 2010). With oil starting to flow from East Siberia to Asia in 2009 through the East Siberia-Pacific Ocean Pipeline (ESPO), one could argue that Dubai's role has now expanded into Russia, as ESPO currently trades as a differential to Dubai. Dubai became the main price marker for the Gulf region by default in the mid 1980s when it was one of the few Gulf crudes available for sale on the spot market. Also unlike other countries in the Gulf such as Iran, Kuwait, and Saudi Arabia, until very recently Dubai allowed oil companies to own equity in Dubai production. Up until April 2007, the major producing offshore oil fields of Fateh, SouthWest Fateh, Rashid, and Falah were operated by the Dubai Petroleum Company (DPC), a wholly owned subsidiary of Conoco-Phillips. DPC acted on the behalf of the DPC/Dubai Marine Areas Limited, a consortium comprised of Conoco-Phillips (32.65%), Total (27.5%), Repsol YPF (25%), RWE Dea (10%), and Wintershall (5%). In April 2007, the concession was passed on to a new company, the Dubai Petroleum Establishment (DPE), a 100% government owned company while the operations of the offshore fields were passed to Petrofac which acts on the behalf of DPE. The Dubai market emerged around 1984 when the spot trade in Arabian Light declined and then ceased to exist. When the Dubai market first emerged, few trading companies participated in this market with little volume of trading taking place. This however changed during the period 1985-1987 when many Japanese trading houses and Wall Street refiners started entering the market. The major impetus came in 1988 when key OPEC countries abandoned the administered pricing system and started pricing their crude export to Asia on the basis of the Dubai crude. Over a short period of time, Dubai became responsible for pricing millions of barrels on a daily basis and the Dubai market became known as the 'Brent of the East' (Horsnell and Mabro, 1993).

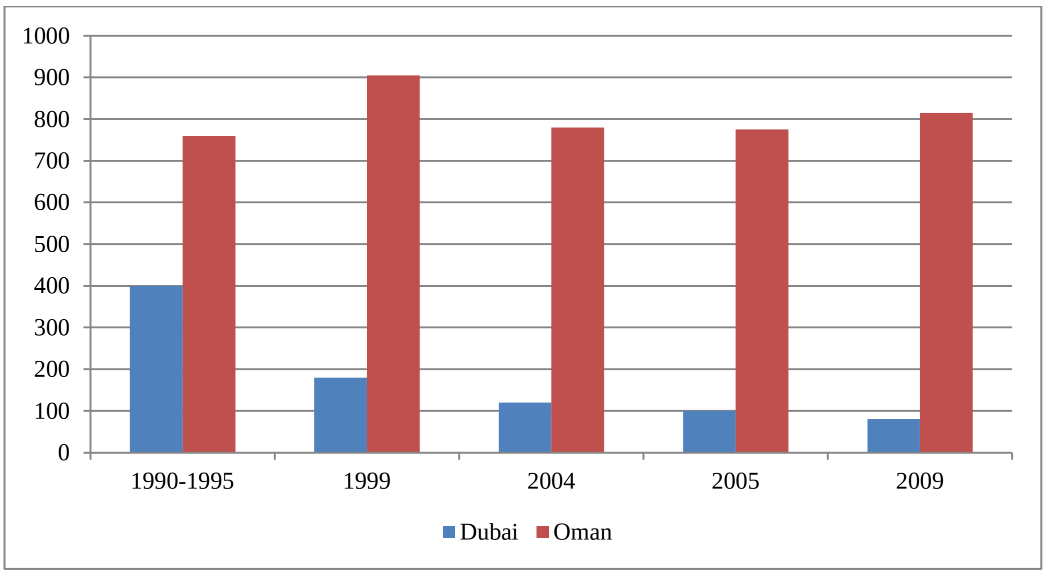
Dubai is not the only benchmark used for pricing cargoes in or destined to Asia-Pacific. Malaysia and Indonesia set their own official selling prices. Malaysia's sales are set on a monthly-average of price assessments by panel Asia Petroleum Price Index (APPI) plus P-Factor premium which is determined by the national oil company Petronas. Indonesia sells its cargoes on the basis of the Indonesian Crude Price (ICP) which is based on a monthly average of daily spot price assessments. While some cargoes are priced as a differential to Indonesian Minas and Malaysian Tapis, these benchmarks have fallen in favour with Asian traders. Since APPI and ICP are often used to price sweet crudes, trading against Dated Brent for sweet crudes has been on the increase in Asia, a trend which is likely to consolidate as the physical liquidity of the key Asian benchmarks Tapis and Minas continues to decline. This should be of concern to producers and consumers as the Dated Brent benchmark may not necessarily be fully reflective of supply/demand fundamentals in East of Suez markets. Abu Dhabi, Qatar and Oman also set their own official selling prices. The former two countries set their OSP retroactively. For instance, the OSP announced in October refers to cargoes that have already been loaded in September. To reflect more accurately market conditions, spot cargoes traded in October or November are often traded as differentials to OSP. Dubai and Oman shifted from a retroactive pricing system to a forward pricing system based on the DME Oman Futures contract. The pricing off the DME contract however still comprise only a small percentage of Gulf crude exports to Asia.

The Physical Base of Dubai and Oman

In the early stages of the current oil pricing system, Dubai benchmark only included crude oil produced in Dubai's fields. The volume of Dubai crude production has dropped from a peak of 400,000 b/d in the period 1990‒95 to under 120,000 b/d in 2004, with production hovering around 90,000 b/d in 2009 i.e. there are about six cargoes of Dubai available for trade in every month (See Figure 18). The most recent (unofficial) figures suggest that Dubai's production may have fallen further to 60,000 b/d i.e. less than four cargoes a month with few of these cargoes sold under long-term contracts. Thus, though Dubai cargoes may be offered sporadically on the spot market for sale, it rarely if ever does trade. The government's decision not to renew the oil concession in 2007 also meant that Dubai no longer satisfies the ownership diversification criterion. The low volumes of production and thin trading activity render the process of price discovery on the basis of physical transactions not always feasible. In a sense, Dubai has turned into a brand or index which represents a sour basket of mid sour grades.[87]

The rapid decline in Dubai output has increased the importance of Oman in pricing crude oil in the East of Suez. Oman has some of the characteristics to enable it to play the role of a benchmark such as the volume of physical liquidity. In 2009, Omani crude oil production reached 815,000 b/d compared to an average of 760,000 b/d in 1990-1995. The production is not subject to OPEC quotas as Oman is not a member of OPEC and there are no destination restrictions. On the other hand, Omani crude oil production is almost totally controlled by PDO, an upstream operating company which is responsible to all the equity producers for optimising production and delivery through Mina Al Fahal. PDO is owned by the Omani government (60%), Shell (34%), Total (4%) and Partex (2%). This structure has remained stable since 1977. There is an array of foreign and private domestic oil companies operating outside PDO, but these constitute a small share of total oil output. In 2009, PDO accounted for more than 90% of the country's total crude oil production.

Figure 18: Dubai and Oman Crude Production Estimates (thousand barrels per day)



Source: Leaver, T. (2010), DME-Oman: Transparent Pricing and Effective Risk Management in a New Era, Presentation at the Asia Oil and Gas Conference, Kuala Lumpur, June.

The Financial Layers of Dubai

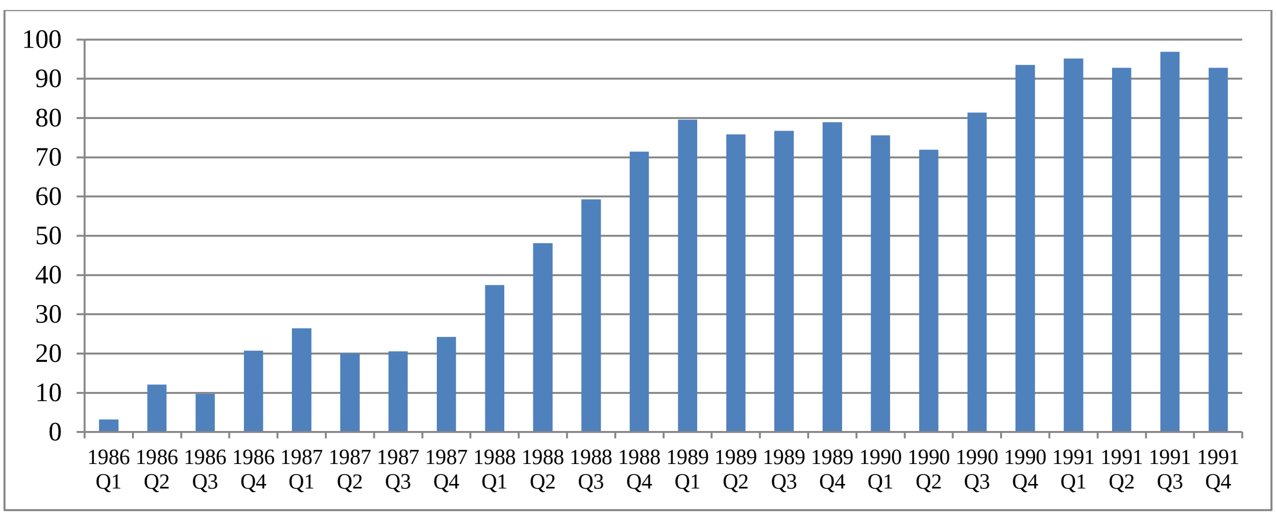
Unlike Brent, very few financial layers have emerged around Dubai. Attempts to launch a Dubai futures contracts in London and Singapore were made in the early 1990s, but such attempts did not succeed. Instead, the informal forward Dubai market remained at the centre of the Dubai complex. In the early stages of its development, producers with entitlement to production used to place their cargoes in the forward market. Being a waterborne crude, Dubai shared many of the features of the forward Brent market with some institutional differences such as the process of nomination, the announcement of the loading schedule, and the duration of the book-out process (for details see Horsnell and Mabro, 1993).

[87] One observer argues that the actual production or even non-existent of Dubai crude oil is irrelevant. What is of relevance is that by buying the Dubai brand or index one can obtain physical oil and by selling the Dubai index one has the obligation to deliver physical oil.

Currently, the two most important layers surrounding the Dubai market are the Brent/Dubai Exchange of Futures for Swaps (EFS) and the Dubai inter-month swaps markets. The Brent/Dubai EFS is similar to the EFP discussed above but where a trader converts a Brent futures position to a forward month Dubai Swap plus a quality premium spread. This market allows traders to convert their Dubai price exposure into a Brent price exposure which is easier to manage given the high liquidity of the Brent futures market. As in the case of an EFP, the EFS is reported as a differential to the price of ICE Brent. It was not possible to obtain data on EFS volumes, but sources estimate that the volumes of Brent-Dubai EFS and Brent-Dubai swaps in total are about 1,000-2,000 lots on an average day (i.e. about 1 million-2 million b/d) and can easily exceed 2,000 lots on a relatively busy day. The Dubai inter-month swap reflects the price differential between two swaps and thus is different from cash spreads. It allows traders to hedge their position from one month to the next. Dubai inter-month swaps are actively traded in London and Singapore and are central to the determination of the forward Dubai price. The actual volumes of inter-month Dubai is also not available, but traders reckon that about 2,000 lots of Dubai swaps (which includes Dubai outright swaps and inter-month Dubai swaps) trade on an average day. Other sources suggest a higher estimate with the volume of total Dubai swap (the swap leg of Brent-Dubai and intermonth combined) in the range of 8000-10000 lots per day of which around 60% is cleared by ICE or CME. The participants in these markets are quite diverse. Apart from some Japanese refiners, the main players include banks (Merrill Lynch BoA, JP Morgan, Morgan Stanley, Societe Generale), refiners (BP, Shell), trading firms (Mercuria, Vitol) and Japanese firms (Mitsui, Sumitomo).

Since 1989, spread deals in Brent-Dubai and inter-month Dubai differentials have dominated trading activity. As seen from Figure 19, while in 1986 outright deals constituted the bulk of the deals in Dubai, by 1989 these had declined to low levels. By 1991, spread deals constituted around 95% of the total number of deals in Dubai with the Brent-Dubai trades playing a central role. In 1991 Brent-Dubai trades accounted for one third of the liquidity and half of the concluded deals with the Brent market providing the Dubai market with the bulk of its liquidity. Given the links with the Brent market, Horsnell and Mabro (1993) argue that 'Dubai has become close to being little more than another Brent add-on market'.

Figure 19: Spread Deals as a Percentage of Total Number of Dubai Deals

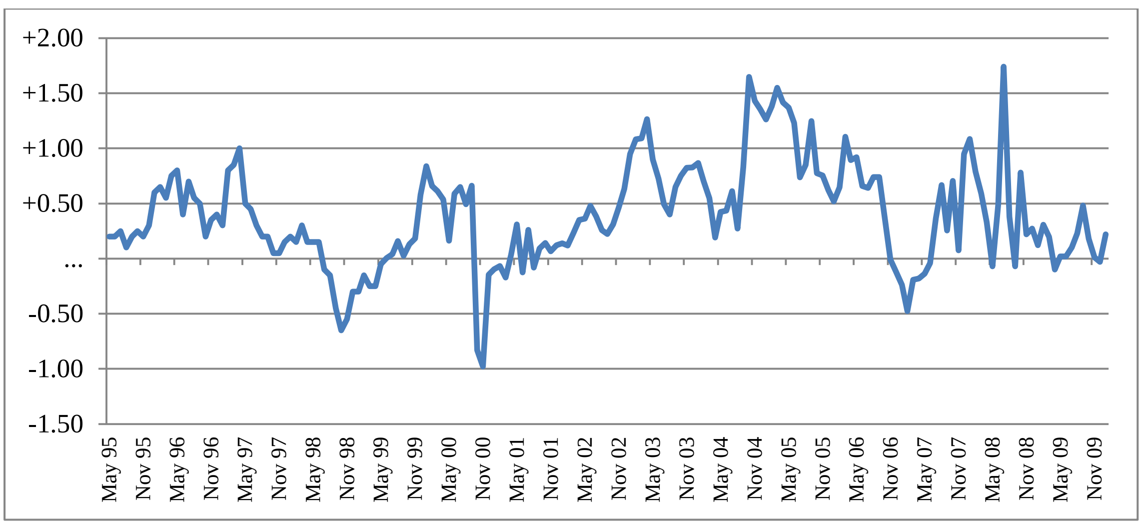


Notes: Spread deals include Dubai one-month spread, Dubai two-month spreads, and Dubai-Brent and Dubai-WTI Spreads.

The Price Discovery Process in the Dubai Market

The two main oil pricing reporting agencies Platts and Argus follow very different methodologies in their assessment of the Dubai price which on many occasions may result in different Dubai prices. Over the years, the declining production of Dubai has pushed Platts to search for some alternatives to maintain the viability of Dubai as a global benchmark. In 2001, it allowed the delivery of Oman against Dubai contracts. In 2004, Platts introduced a mechanism known as the partials mechanism, to counteract the problem of Dubai's low liquidity.[88] The partials mechanism has the effect of slicing a Dubai cargo (as well as Oman) into small parcels that can be traded. The smallest trading unit was set at 25,000 barrels. Since operators do not allow the sale of cargoes of that volume, it has meant that a seller of a partial contract is not able to meet his contractual obligation. Thus, delivery will only occur if the buyer has been able to trade 19 partials totalling 475,000 barrels with a single counterparty.[89] Any traded amount less than 475,000 barrels is not deliverable and should be cash settled (Platts, 2004).[90] Platts allows for the delivery of Omani crude oil or Upper Zakum against Dubai in case of physical convergence of the contract. In other words, the buyer has to accept the delivery of a usually higher-value of an Oman cargo or an Upper Zakum against the Dubai contract. The addition of Oman has created problems of its own. In the Dubai-Oman benchmark, Oman crude has lower sulfur content and higher gravity than the Dubai crude. In some periods depending on the relative demand and supply for the various crudes, the price gap between the two types of crude tends to widen. As seen in Figure 20, the differential is quite variable reaching more than $1.50 in some occasions. As a result of this divergence, many observers have called for the inclusion of another type of crude in the Dubai assessment process which is closer to Dubai than it is to Oman.[91]

Figure 20: Oman-Dubai Spread ($/Barrel)



Source: Oil Market Intelligence

The price of Dubai is assessed based on concluded deals of partials in the Platts window, failing that on bid and offers and failing that on information from the swap markets surrounding Dubai. Thus, despite the fact that NOCs in the Gulf have large physical liquidity which in principle allows them to set the oil

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[88] A market was developed in the 1980s to trade Brent partials but with the development of the Brent futures market, the market became redundant. But trade in partials is still used by Platts to assess North Sea and Dubai crudes.

[89] This is equivalent to a full 500,000-barrel cargo with an implied operational tolerance of minus 5%.

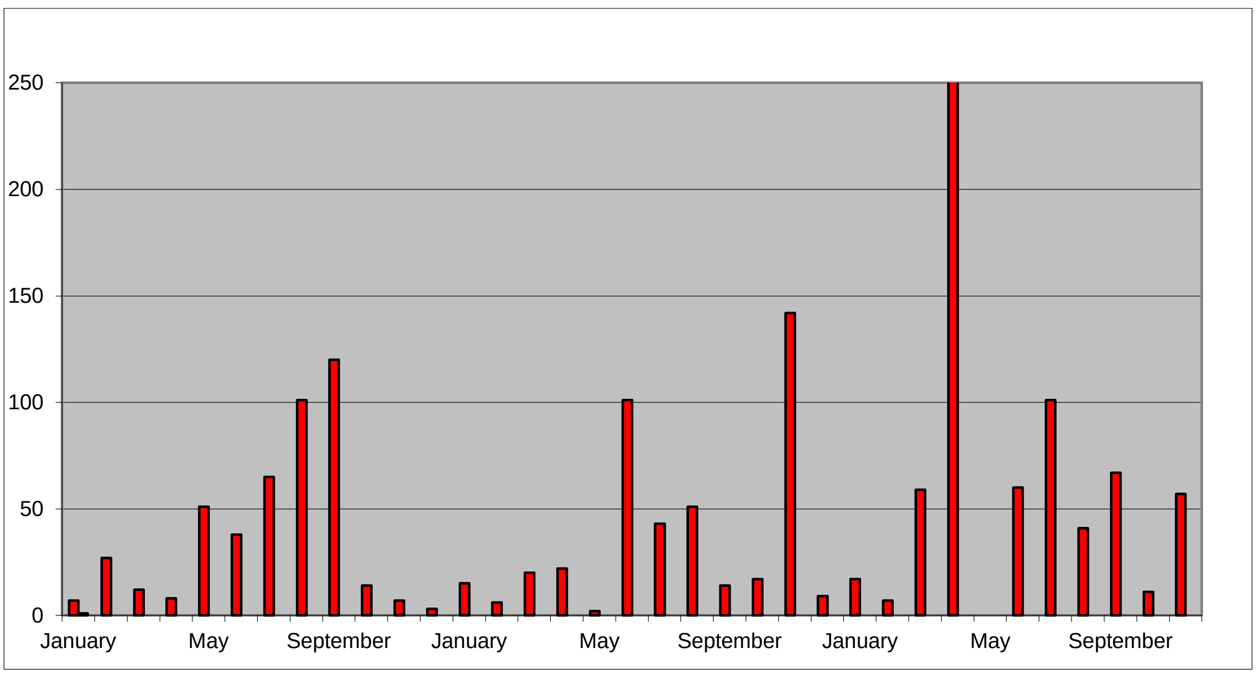
[90] Settlement of cash differences that result from undeliverable partials uses the last price assessment of the trading month.

[91] The pricing of a crude off Dubai-Oman requires setting two coefficients of adjustment (one off Dubai and one off Oman) and then taking some average between the two coefficients.

price, oil exporting countries have avoided assuming this role, shifting the power to set the price to few traders that participate in the Platt's window. Oil exporting countries do not participate in the window; they simply take Platts assessment of Dubai and use it in their pricing formula. This transfer of the pricing discovery role to Platt's window achieves an important objective as oil exporters do not want to be seen as influencing oil prices: it is the market that sets the oil price, and not oil exporters. On other hand, this transfer of power creates some sort of mistrust in the trading activity in the Platts window.

Initially, the shift to partial trading in 2004 has produced encouraging results, increasing the volume of trading activity and hence improving the efficiency of price discovery, reducing the bid/offer spreads, and attracting new players to the market (Montepeque, 2005). However, in recent years, the liquidity in Platts' Dubai window has declined to a point when only few deals are concluded during a month (Figure 21). In many days, there is no execution of partial trades. In fact, since October 2008, there has been no execution of partial trades in 50% of trading days (Leaver, 2010). This however does not preclude Platts from producing a value for Dubai, which can be based on bids and offers and/or information from the value of derivatives. Only a few players such as Sietco, Vitol, Glencore, and Mercuria dominate the Platts Dubai window at any one day. On the sell side, large Asian refineries such as Unipec and SK have been dominant. The concentration of trading activity in the hands of few players in the Platts partials market has raised serious concerns that some traders by investing as little as in a 25,000-barrel partial contract can influence the pricing of millions of barrels traded everyday (Binks, 2005). However, market participants who think that prices are being manipulated by a few players have the incentive to enter Platts window and exert their influence on the price. Critics argue that barriers to entry can prevent such an adjustment mechanism from taking place.

Figure 21: Dubai Partials Jan 2008 - Nov 2010



Source: Platts

The way that Argus derives the Dubai price sheds some light on the links between the various financial layers surrounding Dubai. Argus' approach for assessing Dubai is based on deriving information from various OTC markets, the most important of which is the Exchange for Swaps (EFS) and the inter-month Dubai spread contracts. The EFS price is reported as a differential to the ICE Brent futures contract. This allows Argus to identify a fixed price for Dubai in a particular month referred to as the price of Dubai Swap. But since Dubai is loaded two months ahead, the assessed price of Dubai say in the month of

December is the forward price of Dubai in February i.e. it is price for delivery of Dubai in the month of February (call it *x*)[92]. But buyers and sellers are interested in the price of Dubai in December. To derive the price of Dubai in December, the information from the inter-month Dubai spread market is used. Specifically, the January-February Dubai swap price differential is subtracted from *x* which gives the price of delivery of Dubai in January (call it *y*).[93] The January-December Dubai swap price differential is next subtracted from *y* to give us the price of Dubai for the month of December.[94]

Once the price of Dubai is identified, the derivation of the Oman price follows in a rather mechanical way, mainly by exploiting information about Dubai-Oman spreads. If Oman partials are traded in the window, Platts uses the price of concluded deals or bids/offers to derive the Oman price. When this is not feasible, the Oman value will be assessed using the Oman-Dubai swaps spread[95], a derivative contract which trades the differential between Oman's OSP and Dubai for the month concerned. The contract is traded over the counter and does not involve any physical delivery. The Dubai-Oman swap price differential will then be used in a formula which links it to the value of Dubai. Similarly, Argus assesses the value of Oman by comparing the value of Oman with that of Dubai. Argus first calculates the differential to Dubai swaps and then adds it or subtracts it from Dubai outright swap to get the Oman forward price. So currently, the assessment of Oman price by PRAs is a simple extension of the Dubai market, where the Dubai/Oman spread provides the necessary link.

The above price derivation shows clearly that the Brent futures market sets the price level while the EFS and the inter-month Dubai spread market set the price differentials. These differentials are in turn used to calculate a fixed price for Dubai. In a sense, the price of Dubai need not have a physical dimension. It can be derived from the financial layers that have emerged around Dubai. This has raised some concerns as 'calls to use swaps as pricing benchmarks for physicals are at best uninformed as swaps are derivatives of the core physical instruments' (Montepeque, 2005). But this neglects the fact that liquidity in Platts Dubai's window is thin. In addition, the argument against using swaps is inconsistent with Platts' use of swaps (CFDs) in identifying the price of Dated Brent. It is also inconsistent with the fact that at times when no partials are trading, Platts has no alternative but to use the EFS to identify the Dubai price.

Another concern is that unlike the WTI-Brent differential which reflects the relative market conditions in Europe and the USA, Horsnell and Mabro (1993) argue that the Brent-Dubai differential does not usually reflect the trading conditions of Asian markets except on some rare occasions such as the Iraqi invasion of Kuwait. In normal times, Dubai crude is more responsive to trading conditions in Europe and the US than the Far East. Specifically, the authors argue that the Brent-Dubai differential reflects better the relationship between prices of sweet and sour crudes. In support of this hypothesis, they argue that when OPEC decides to cut production, these cuts affect the production of heavy sour crudes. As a result, the price of these crudes will strengthen relative to sweet crudes leading to the strengthening of Dubai prices relative to Brent. The recent growth of the Asia-Pacific market and the wide entry of Asian players may have changed these dynamics with the Dubai-Brent spread currently responding more closely to Asia's trading conditions making Brent-related cargoes either more attractive (small Brent premium) or less attractive (large Brent premium) to Asia-Pacific buyers, but this need further empirical investigation.

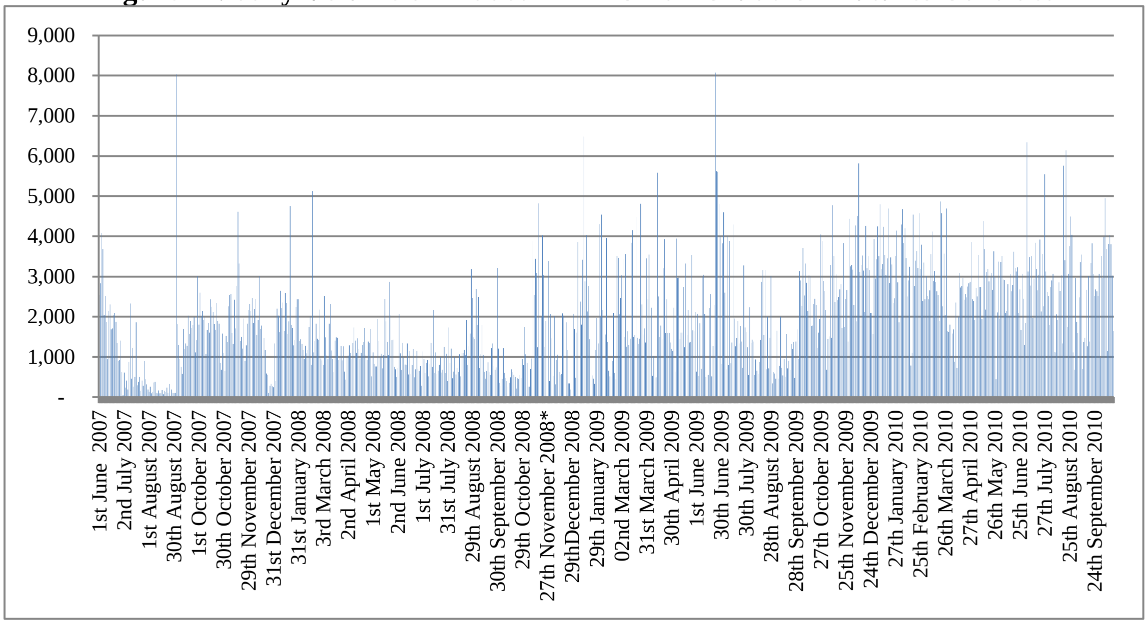
Oman and its Financial Layers: A New Benchmark in the Making?

In June 2007, the Dubai Mercantile Exchange (DME) launched the Oman Crude Oil Futures Contract to serve as a pricing benchmark of Gulf exports to Asia and as a mechanism to improve risk management. Figure 22 below shows the daily volume of DME Oman futures contracts traded between June 2007 and September 2010. The figure suggests that the volume of contracts traded is highly volatile, but remains

[92] This is referred to as Dubai Third Forward Month.
[93] This is referred to as the Dubai Second Forward Month.
[94] This is referred to as the Dubai Swap First Month.
[95] Oman swap is a derivative of the Platts' cash Oman assessment. However, in the absence of bids and offers for Oman swaps, Platts uses the information from the structure of the Dubai forward curve for assessing Oman swaps.

relatively low. In 2009, the average daily volume of traded contracts amounted to slightly more than 2000 contracts, which is very low especially when compared to the traded volume of WTI or Brent futures contracts.

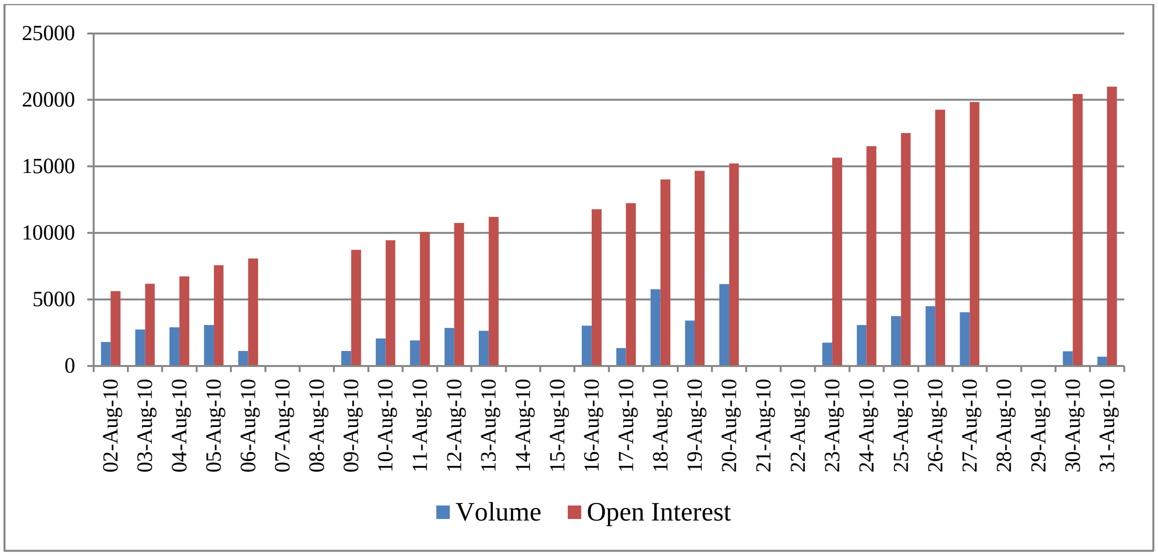
Figure 22: daily Volume of Traded DME Oman Crude Oil Futures Contract



Source: CME Group

DME's Oman futures contract allows settlement against physical delivery of Oman crude. One interesting feature of the DME futures contracts is the large number of contracts that converge for physical delivery in any given month. Figure 23 below traces the evolution of the trading volume and open interest for the October 2010 Futures contract during the month of August. On 31st August, 2010 the open interest reached almost 21,000 contracts. This is equivalent to 21 million barrels a month comprising more than 80% of Oman's monthly crude oil production. By any standard, these are very large volumes to be delivered through futures contracts. For instance, physical delivery on the Light Sweet Crude Oil Futures contract exceeded four million barrels only once in January 1995. Also in contrast with other benchmark contracts, the open interest on the DME contract tends to increase as contract expiry approaches as shown in Figure 21. This represents an important anomaly and implies that the DME contract is simply used as a means to access physical Oman crude oil. This feature sets aside the DME contract from the other successful futures contracts that have evolved around Brent and WTI.

Figure 23: Volume and Open Interest of the October 2010 Futures Contracts (Traded During Month of August)



Source: DME Website

The introduction of the DME contract has changed the pricing mechanism of Omani crude. From its inception, it was clear that both a retroactive official selling price (OSP) and futures market-related price undermined the market function of price discovery.[96] Thus, it was a matter of time before Oman decided to change its pricing from a retroactive pricing system to a forward pricing system based on the DME contract. The OSP for Oman crude for physical delivery is calculated as the arithmetic average of the daily settlement prices over the month. For instance, the OSP for Oman crude for the month of June is calculated as the arithmetic average of the daily settlement of price over the month of June for delivery in two months i.e. in the month of August. The Government of Dubai has also ceased the pricing of its crude oil sales off its current mechanism and instead utilises DME Oman futures prices providing additional boost to the contract. Dubai and Oman however have been the exceptions so far. Despite Dubai's low physical liquidity, Platts Dubai/Oman assessments are still the preferred price benchmark used in the pricing formula for exports to Asia. This raises the question why other Middle Eastern producers have not been enthusiastic about adopting the DME Oman Crude Oil Futures contract as the basis of pricing crude oil.

The futures market plays two important roles: price discovery and hedging/speculation or what is termed as risk management. Liquidity is crucial for the efficient performance of these two functions. Physical deliverability, which the DME tends to emphasize, is less important. In other words, deliverability is not a sufficient condition for the success of the DME Oman contract. In fact, physical deliverability can reduce the chances of the success of a futures contract if market participants have doubts about the likely performance of the delivery mechanism or if physical bottlenecks around delivery points result in some serious dislocations although the extensive use of the DME's physical delivery mechanism demonstrates confidence in its performance. Nevertheless, inability to increase trading liquidity while physical deliverability continues to rise may undermine the contract as the risk of physical delivery tends to rise, especially for those players that are not interested in physical delivery in the first place. If low liquidity persists, then the two functions of price discovery and risk management would be undermined and the contract would fail to attract the attention of market participants.

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[96] In a retroactive pricing system, the OSP applied to cargoes that have already been loaded. In a forward pricing system, the price for an oil shipment to be loaded say in May is determined two months before i.e. in March.

Asian interest is crucial for the long term success of the contract as the Asia-Pacific region is the main importer of Middle Eastern sour crude oil. However, big Asian refineries haven't so far shown strong enthusiasm for the contract. As to the financial players/speculators, the DME futures contract can open new opportunities for trading and risk management. But speculative and hedging activity will not be attracted to a market with low liquidity. Market participants often prefer to trade only in the most liquid markets. The recent launch by CME of DME linked swap and option contracts is geared to providing new risk management tools in the hope of attracting more financial players and Asian refineries into the market. While Gulf oil producers do not hedge their oil production in the futures market, they have interest in a sour futures contract for export pricing purposes. Low liquidity however is likely to discourage the already very cautious Gulf oil exporters from setting their crude price against the DME futures contracts. So far, none of the big gulf producers such as Saudi Arabia, Kuwait, Qatar, and Iran have shown much interest in the newly established sour futures contracts. However, there is the temptation for some Gulf countries to shift part of the global oil trading activity to the region, which may induce a change in some oil exporters' attitude towards the contract. There is also strong interest in the success of the DME contract as evidenced by the heavy involvement of the CME Group and the various stakeholders.[97] Without this strong interest and support, the contract would have perhaps failed by now.

[97] The DME is a joint venture between Tatweer (a member of Dubai Holding), Oman Investment Fund and CME Group. Global financial institutions and energy trading firms such as Goldman Sachs, J.P. Morgan, Morgan Stanley, Shell, Vitol and Concord Energy have also taken equity stakes in the DME (Source: Dubai Mercantile Exchange Website).

8. Assessment and Evaluation

Based on the above detailed analysis of the various benchmarks and their surrounding layers, it is possible to draw some broad implications which can be grouped as follows: the physical liquidity of benchmarks; the new dynamics of oil trade flows and its implications on pricing benchmarks; the nature of players in the market; the linkages between physical and financial layers; the process of price adjustment; and transparency in oil markets.

Physical Liquidity of Benchmarks

An interesting feature of the current oil pricing system is that markets with relatively low volumes of production such as WTI, Brent, and Dubai-Oman set the oil price for markets with much higher volumes of production in the Gulf and elsewhere in the world. Despite the high level of volumes of production in the Gulf, these markets remain illiquid, as there are limited volumes of spot trading, no forwards or swaps (apart from Dubai), no liquid futures market, and destination restrictions which prevent on-trading in chains. Furthermore, these markets are characterised by lack of equity diversification.

While adequate physical liquidity is not a sufficient condition for the emergence of benchmarks, it is a necessary condition for a pricing benchmark's long-term success. Some observers have argued that in principle, there is not a certain level of production below which the integrity of the market is threatened. Before its substitution by WTI, the Alaskan North Slope (ANS) continued to generate market prices although the physical base was very narrow. The prices were derived completely from oil price reporting agencies' assessments of traders' perceptions about what the price would be if there were actual trade in cargoes. This argument however is unconvincing because confidence is unlikely to survive for long in markets with low physical liquidity.[98] As markets become thinner and thinner, the price discovery process becomes more difficult as oil reporting agencies cannot observe enough genuine arms-length deals. Furthermore, in thin markets, the danger of squeezes and distortions increases and as a result prices could then become less informative and more volatile thereby distorting consumption and production decisions (Pirrong, 1996). [99] A squeeze refers to a situation in which a trader goes long in a forward market by an amount that exceeds the actual physical cargoes that can be loaded during that month. If successful, the squeezer will claim delivery from sellers (shorts) and will obtain cash settlement involving a premium. One consequence of a successful squeeze is that the price of the particular crude that has been squeezed will rise relative to that of other marker crudes. Squeezes also increase the volatility between prices in different layers such as between the Dated Brent and the forward Brent giving rise to new financial instruments to manage this risk such as CFDs. Squeezes are made possible by two features: the anonymity of trade and the huge volume of trading compared to the underlying physical base (Mollgaard, 1997). After all, squeezes are much easier to perform in a thin market (Telser, 1992). This is in contrast with futures markets where the volume of transactions is quite large and thus there is less room for squeezes and manipulation, although futures markets are not totally immune.[100] Squeezes are also

[98] The fact that ANS stopped acting as a benchmark suggests that there is a level below which integrity of the benchmark is threatened.

[99] See for Instance, Liz Bossley (2003), Battling Benchmark Distortions", Petroleum Economist, April. More recently, concerns about squeezes arose when one oil trader HETCO took control of the first eight North Sea Forties crude oil cargoes loading in February 2011 and two Brent cargoes with market observers describing such a move as a 'trading play' intended to influence the spot market. Reuters (2011), 'Oil Trader Takes Control of 10 North Sea Oil cargoes', January 18.

[100] The challenge of the U.S. Federal trade commission to the BP Amoco-Arco merger was partly based on the fear that by controlling the physical infrastructure, the WTI futures market can be squeezed. The Federal trade commission notes that 'the restriction of pipeline or storage capacity can affect the deliverable supply of crude oil in Cushing and consequently affect both WTI crude cash prices and NYMEX futures prices' (p.7). Then it states that 'a firm that controlled substantial storage in Cushing and pipeline capacity into Cushing would be able to manipulate NYMEX futures trading markets and they enhance its own positions at the expense of producers, refiners and

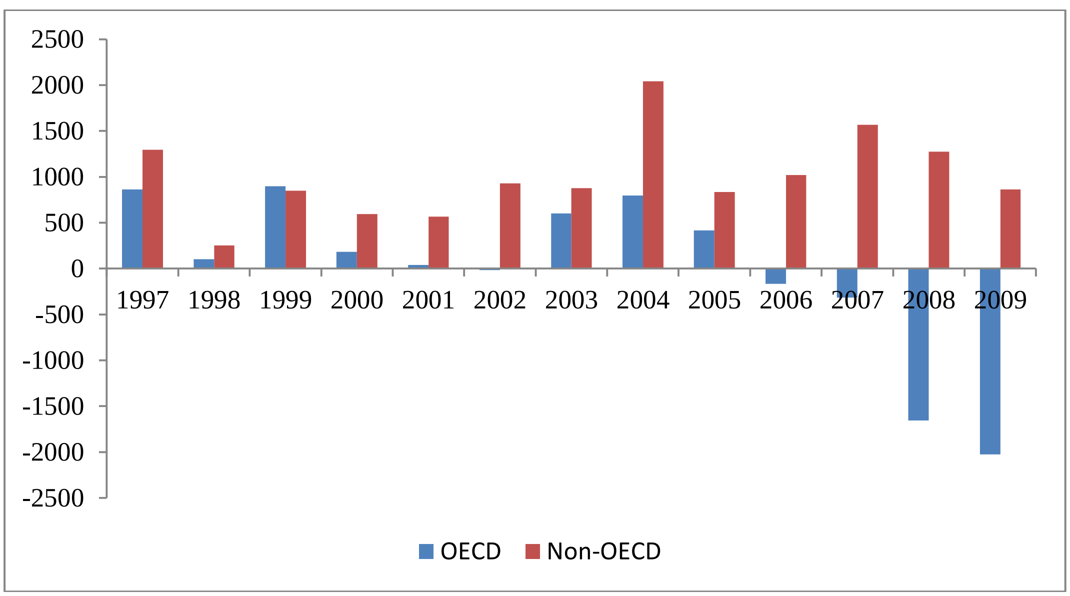
becoming less prevalent in jurisdictions where regulators enforce the laws against abuse of market power, and where those laws are clear. Also important is the design or the architecture of the market/contracts in which PRAs, in consultation with market participants, play a key role in determining its main features and structures and evolution over time. Regulators have also turned their attention to this issue where some observers consider that 'the proposed spot-month position limit formula seeks to minimize the potential for corners and squeezes by facilitating the orderly liquidation of positions as the market approaches the end of trading and by restricting the swap positions which may be used to influence the price of referenced contracts'.[101]

So far the low and the rapid decline in the physical base of existing benchmarks have been counteracted by including additional crude streams in assessed benchmark. This had the effect of reducing the chances of squeezes as these alternative crudes could be used for delivery against the contract. Although such short-term solutions have been successful in alleviating the problem of squeezes, they should not distract observers from raising some key questions: What are the requisite conditions for the emergence of successful benchmarks in the most liquid market in terms of production? Would a shift to price assessment in such markets improve the price discovery process? Such key questions remain heavily under-researched in the energy literature and do not feature in the producer-consumer dialogue.

Shifts in Global Oil Demand Dynamics and Benchmarks

One of the most important shifts in oil market dynamics in recent years has been the acceleration of oil consumption in non-OECD economies. Between 2000 and 2009, demand growth in non-OECD outpaced that of OECD in every year (see Figure 24). During this period, non-OECD oil consumption increased by around 10.5 million b/d while that of OECD dropped by 2.1 mb/d. At the heart of this growth lies the Asia-Pacific region which accounted for more than 50% of this incremental change in demand during the 10-year period.

Figure 24: OECD and Non-OECD Oil Demand Dynamics



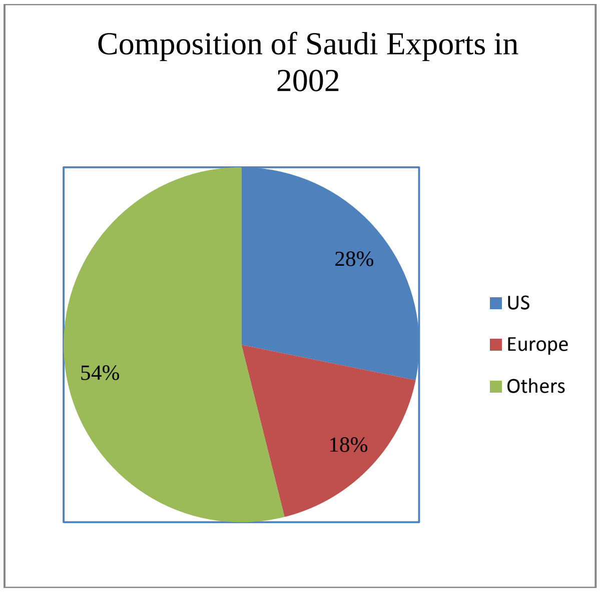
Source: BP (2010)

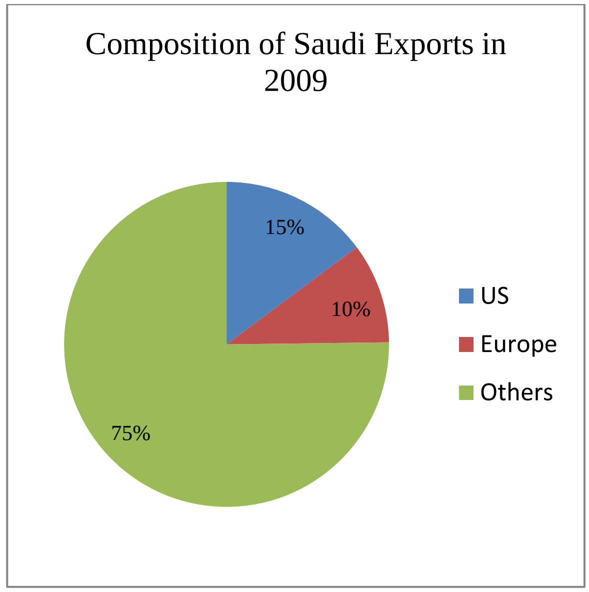
traders' (p. 7) (United States of America Before Federal Trade Commission in the Matter of BP AMOCO P.L.C. and Atlantic Richfield Company downloadable from http://www.ftc.gov/os/2000/08/bparco.pdf

[101] 'Proposed Position Limits for Derivatives', Statement of Bruce Fekrat, Senior Special Council, Division of market Oversight, CFTC, December 16, 2010.

The emergence of the non-OECD as the main source of growth in global oil demand has had far reaching implications on the dynamics of oil trade flows. This is perhaps best illustrated in the shift in the direction of oil flows from Saudi Arabia and Russia, the two biggest oil producers in the world towards the East. As shown in Figure 25, in 2002 Saudi Arabia's share of oil exports to the US and Europe amounted to 28.2% and 17.9% respectively. In 2009, these shares declined to 17.8% for the US and 10% for Europe. In 2009 Saudi Arabia abandoned its St Eustatius storage facility in the Caribbean which was mainly used to feed US markets and instead obtained storage facility in Japan to feed Asian markets.

Figure 25: Change in Oil Trade Flow Dynamics





Source: Barclays Capital, Oil Sketches, 23 April 2010

So far, Russia's exports have been heavily concentrated towards Europe to which in 2009 it exported around 7 mb/d compared with 1.17 mb/d to Asia Pacific.[102] These dynamics however are changing as Russia builds new infrastructure in an attempt to shift part of its oil exports towards the Far East. The inauguration in December 2009 of the first section of the Eastern Siberia Pacific Ocean (ESPO) pipeline represents a marginal but nonetheless important step in that direction. The first section of ESPO is a 2,757 km long pipeline connecting Taishet in East Siberia to Skovorodino in Russia's Far East, near the border with China. It has a capacity of 600,000 b/d is expected to grow to 1 million b/d by 2012, and potentially to as much as 1.6 million b/d in 2015. The second stage of the project involved linking Skovorodino to a new export terminal at Kozmino on the Pacific coast in order to supply some of the rapidly growing oil demand in Asia. China and Russia then agreed to construct an offshoot from Skovorodino to Daqing in China with a capacity of 300,000 b/d. It was completed by the close of 2010.

Such changes in trade flow patterns are likely to accelerate as the centre of consumption growth continues to shift from OECD to emerging economies. The EIA[103] predicts that between 2007 and 2035, oil consumption is expected to increase by around 24 mb/d from 86.1 mb/d to 110.6 mb/d with non-OECD accounting for almost all of the increase during this period. This shift in the dynamics of trade flows towards the East is likely to have profound implications on pricing benchmarks. Questions are already being raised as to whether Dubai, Minas and Tapis still constitute appropriate benchmarks for pricing oil in Asia given their low liquidity or whether new benchmarks are needed to reflect more accurately the

[102] BP (2010), BP Statistical Review of World Energy, June.
[103] EIA (2010), International Energy Outlook 2010, US Energy Information Administration, Table A.5.

shift in trade flows. In this respect, a debate has already started on the suitability of ESPO to act as an Asian benchmark.[104] Since ESPO competes with Mideast crudes, so far ESPO has strengthened the Dubai benchmark. Since December 2009, Platts has been assessing the value of ESPO but as a differential to Platts' Dubai. In the longer term, ESPO has some of the features that may allow it to assume the role of a benchmark itself. The pricing point in Northern Asia is particularly attractive. ESPO is close to key refining centres in China, Japan and South Korea where the sailing time from the loading port of Kozmino to northeast Asia is just a few days, transforming the Asian market from a long haul to a short haul market. Furthermore, ESPO volumes are larger than many of the existing benchmark and could increase in the future. On the other hand, there is uncertainty about the volume that will be available for sale in the spot market as a considerable amount of it is sold on long-term basis or used in Rosneft refineries. There is also uncertainty about the quality of ESPO over time. Most importantly, for any benchmark to emerge, market participants should have confidence that the benchmark is not subject to manipulation which is yet to be proven. One must consider the legal, tax, and regulatory regime operating around any particular benchmark. WTI has the US government overseeing it and a robust legal regimen. Brent has also stable governmental oversight. Distrust of the Russian government is strong in many companies and hence the reluctance so far to support an ESPO benchmark. Nevertheless, if discontent with existing benchmarks intensifies, then ESPO could be one of the few options available for the industry to fall back on.

Regardless of whether or not ESPO will eventually emerge as a benchmark, it is already having an impact on pricing dynamics in Asia. In a sense, ESPO is likely to become or has become the marginal barrel in Asia, displacing West African crudes in this role. Gulf suppliers have to monitor ESPO's performance very closely when setting their price differential in relation to Dubai to maintain their export competitiveness to Asia. This is likely to cause a decline in the size of the 'Asian premium' over time.

The Nature of Players and the Oil Price Formation Process

In recent years, the futures markets have attracted a wide range of financial players including pension funds, hedge funds, index investors, technical traders, and high net worth individuals. Many reasons have been suggested on why financial players have increased their participation in commodities markets. The historically low correlation between commodities' returns in general and other financial assets' returns, such as stocks or bonds, has increased the attractiveness of holding commodities for portfolio diversification purposes for some institutional investors. Because commodity returns are positively correlated with inflation, some investors have entered the commodities market to hedge against inflation risk and weak dollar. Expectations of relative higher returns in investment in commodities due to perception of tightened market fundamentals have motivated many investors to enter the oil market. Finally, financial innovation has provided an easy and a cheap way for various participants, both institutional and retail investors, to gain exposure to commodities.

The entry and the impact of financial players has been the subject of various empirical studies. Some examine whether these players had a destabilising effect on commodities futures markets.[105] Other studies focus on the impact of players on the inter-linkages between commodities markets and other financial markets such as equity.[106] While these and other similar studies provide some valuable insights into the issue of linkages between financial layers and physical benchmarks, it is important to expand the analysis

[104] See for instance, J.P. Morgan (2010), "Will EPSO Emerge as a New Pricing Benchmark?", Presentation at the Platts Crude Oil Methodology Forum 2010, London, May.

[105] See for instance Brunetti and Büyükşahin (2009).

[106] For example, Büyükşahin and Robe (2010) find that the composition of traders plays a role in explaining the joint distribution of equity and commodity returns. Specifically, they find that a subset of hedge funds, those that are active both in equity and commodity futures market can explain the increase in the commodity-equity correlations. In contrast, swap dealers, index traders, and floor brokers and traders play no role in explaining cross-correlations across markets.

to the trading strategies of physical players. The fact remains that the participants in many of the OTC markets such as forward markets and CFDs which are central to the price discovery process are mainly 'physical' and include entities such as refineries, oil companies, downstream consumers, physical traders, and market makers. Financial players such as pension funds, index and retail investors have limited presence in some of these markets. Thus, any analysis limited to the role of non-commercial participants in the futures markets in the oil price formation process is likely to be incomplete.

The Linkages between Physical Benchmarks and Financial Layers

At the early stages of the current pricing system linking prices to 'physical' benchmarks in formulae pricing provided producers and consumers with a sense of comfort that the price is grounded in the physical dimension of the market. Suspicion still exists on whether the oil price derived from paper markets such as the futures market reflects the physical realities of the oil market at the time of pricing. Sceptics argue that prices in these markets are not determined on the basis of trading in real barrels, but rather by trading in financial contracts for future delivery (Mabro, 2008).

The latter concern implicitly assumes that the process of identifying the price of benchmarks can be isolated from financial layers. However, this is far from reality. As our analysis shows, the different layers in the oil market are highly interconnected and form a complex web of links, all of which play a role in the price discovery process. [107] The information derived from financial layers plays an important role in identifying the price level of the benchmark. In the Brent market, the price of Dated Brent is assessed using information from many layers including CFDs, forward markets, EFPs and futures markets. Similarly, in the WTI complex, the prices of the various physical benchmarks are strongly interlinked with the futures markets. The price of Dubai is often derived using information from the very active OTC Dubai/Brent swaps market and the inter-Dubai swap market. Thus, the idea that one can isolate the physical from the financial layers in the current oil pricing regime is a myth. Crude oil prices are jointly or co-determined in both layers, depending on differences in timing, location and quality.

Despite the fact that the price discovery process is influenced by information from paper markets, most players are still reluctant to adopt futures prices in their pricing formulae although some key producers such as Saudi Arabia, Kuwait and Iran use BWAVE (futures price) in pricing their exports to Europe. This can be explained by the fact that since prices in the futures markets reflect the price of oil today for future delivery, they inject a substantial time basis risk. Currently, this basis risk is eliminated by referencing against physical benchmarks and managing the price risk by using swaps against the benchmark price.

The above discussion has also some implications on the pricing of derivatives instruments. Since physical benchmarks constitute the basis of the large majority of physical transactions, some observers claim that derivatives instruments such as futures, forwards, options and swaps derive their value from the price of these physical benchmarks. In other words, the prices of the physical benchmarks drive the prices in paper markets. However, this is a gross over-simplification and does not accurately reflect the process of crude oil price formation as the two layers are highly interlinked. The issue of whether the paper market drives the physical or the other way around is difficult to construct theoretically and test empirically.

Adjustments in Price Differentials versus Price Levels

Our analysis shows the importance of distinguishing between adjustments in price differentials and adjustments in price levels. Trades in the levels of the oil price rarely take place in the layers surrounding the physical benchmarks. Instead, these markets trade price differentials which fluctuate based on hedging pressures and expectations of traders. It is rare (though not unheard of) for companies to take positions on the basis of an outright price movement – that is whether prices go up or down. This is far too risky for

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[107] Platts use the word triangulate: "Assessments will use spread relationships and derivative values to help triangulate value". See Platts Crude Oil Methodology Forum 2010, May 2010 (London).

most participants. Most trade is on spreads of some sort – one regional price against another, one product price against another, one product price against a crude (feedstock) price, one time period price against another time period. These arbitrages self-correct by traders' actions such as buying in one region, where there's too much oil, and transporting it to another region where there isn't enough and where the price is higher to draw in the oil. This feature of the oil pricing system poses a legitimate question: how can markets that actively trade price differentials set a price level for a particular benchmark? As noted by Horsnell and Mabro (1993) in the context of forward Brent,

> In spread deals the relationship between specified flat prices and market prices may not be very tight. And since the focus is to a large extent on relatives, the search for price levels that correspond to the relevant market conditions becomes less broadly based and less active. The liquidity in that part of the market which concerns itself with the oil price level has become a small proportion of the total liquidity of the forward market.

We postulate that the level of the oil price is set in the futures markets; the financial layers such as swaps and forwards set the price differentials. By trading differentials, market participants limit their exposure to risks of time, location grade and volume. These differentials are then used by oil reporting agencies to identify the price level of a physical benchmark. Perhaps this is most evident in the US market. As explained by Platts (2010b),

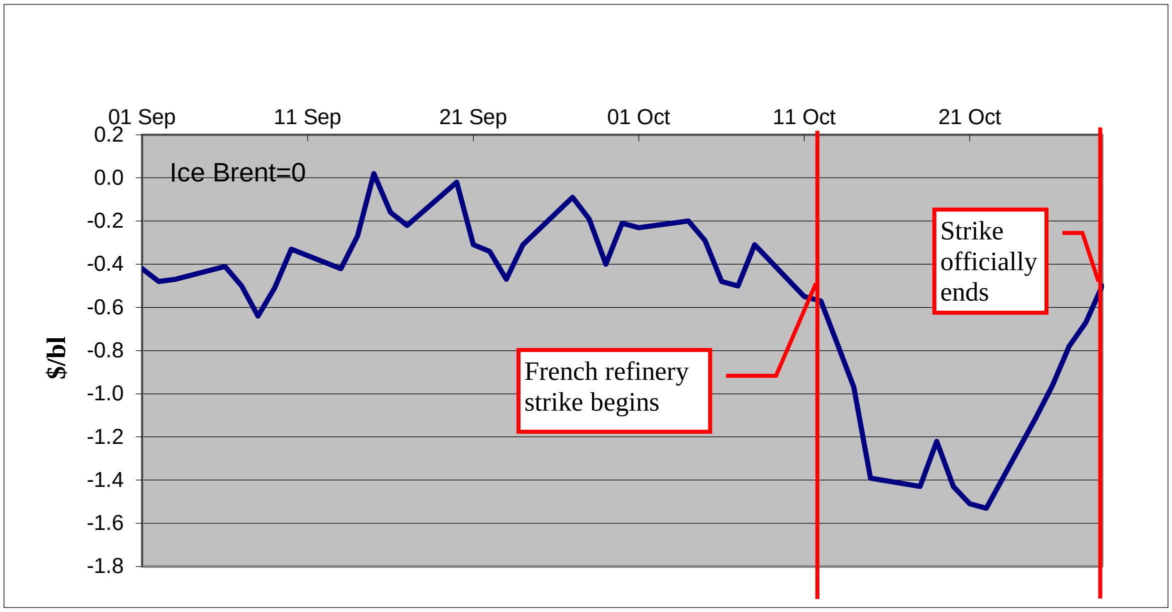
> physical crude oil assessments are still widely used by the industry, but the 'flat' price formation is originated by the New York Mercantile Exchange (NYMEX). The highly liquid sweet crude futures contract traded on NYMEX provides a visible real-time reference price for the market. In the spot market, therefore, negotiations for physical oils will typically use NYMEX as a reference point, with bids/offers and deals expressed as a differential to the futures price…. Therefore, while NYMEX acts as a barometer of market value, and negotiations for physical oil may reference the futures value, Platts plays a distinct and complementary role to that of the exchange (p.3).

To illustrate this last point, the recent strikes in France in October 2010 present a good experiment. As seen in Figure 26 below, during the strike between the period 11th and 21st of October, the price differential between Dated Brent and ICE futures Brent widened considerably reaching a peak of -$1.53 dollars per barrel on the 22nd of October.[108] The widening of the differential reflected the fact that while global oil supplies were not affected by the strike, French refineries could not buy more crude oil which resulted in less overall demand. Oil companies and physical traders holding more oil than originally planned were forced to clear the ex-ante excess supply by offering larger discounts. Thus, in this episode, the bulk of the adjustment took place through the changes in price differentials and not the price levels, perhaps because the market thought the effects of the strike on the oil markets were only temporary.[109]

[108] It is important to note also that there is a good chunk of term structure between prompt Dated Brent and the oil deliverable under the nearest Brent futures contract.

[109] Some consider that such evidence is a clear indication that it is the prompt physical that sets the futures price. Such natural experiments however don't shed light on this issue. One needs to show that these adjustments in differentials occur in other than crisis situations and they are strong enough to drag down the price level. More importantly, such evidence doesn't provide an answer to the question of how the level of oil price is determined in the first place. It reinforces the point, however, that the futures markets set the price level and the physical layers set the differentials, which reflect changes in the underlying fundamentals of the oil market.

Figure 26: The North Sea Dated differential to Ice Brent during the French Strike



Source: Argus

Thus, the level of oil price, which consumers, producers and their governments are most concerned with, is not the most relevant feature in the current pricing system. Instead, the identification of price differentials and the adjustments in these differentials in the various layers underlie the basis of the current oil pricing system. If the price in the futures market becomes detached from prompt fundamentals, the differentials adjust to correct for this divergence through a web of highly interlinked and efficient markets. The key question is whether the adjustments in differentials are strong and large enough to induce adjustments in the futures price level. The issues of whether price differentials between different crude oil markets and between crude and product markets showed strong signs of adjustment and whether those adjustments affected the behaviour of oil price over the 2008-2009 price cycle have not yet received their due attention in the empirical literature.[110]

But this leaves us with a fundamental question: what factors determine the price level of an oil benchmark? The crude oil pricing system and its components such as the PRAs reflect how the oil market functions: if oil price levels are set in the futures market and if participants in these markets attach more weight to future fundamentals rather than current fundamentals and/or if market participants expect limited feedbacks from both the supply and demand side in response to oil price changes, these expectations will be reflected in the different layers and will ultimately be reflected in the assessed price. The adjustments in differentials are likely to ensure that these expectations remain anchored in the physical dimension of the market.

Transparency and Accuracy of Information

The issue of transparency has gained wide credence in the aftermath of the 2008 financial crisis with many organisations such as G8, G20, and the IEF calling for improved transparency as key to enhancing

[110] In fact, one explanation attributes the upward rise in the crude oil price in the first half of 2008 to the high demand for very-low-sulfur diesel (Verleger, 2008). This increased the price differential between diesel and crude oil, which in turn pushed the crude oil price up. Such an explanation points to the importance of integrating products into the analysis. Due to space constraints, products markets were not discussed in this paper, but are the subject of current research at the Oxford Institute for Energy Studies.

the functioning of the oil market and its price discovery function. Transparency in oil markets however has more the one dimension. Although improving transparency in the physical dimension of the market is key to understanding oil market dynamics and enhancing the price discovery function, our analysis shows that transparency in the financial layers surrounding the physical benchmarks is as important. In this regards, it is important to emphasize three dimensions to the transparency issue. First, obtaining regular and accurate information on key markets depends largely on the willingness of PRAs to release or share information. PRAs are under no legal obligation to report deals to a regulatory authority or to make the information at their disposal publicly available. Thus, some basic but key information and data on market structure, trade volumes, liquidity, the players and their nature, and the degree of concentration in a trading day are not always available to the public, but they are sold to market participants at a price which makes it worthwhile for PRAs to collect such data.

Second, the degree of transparency varies considerably within the different layers in the Brent, WTI and Dubai-Oman complexes as well as across benchmarks. Within the Brent complex, the degree of transparency between the various layers such as the Forward Brent, CFD and Dated Brent and futures market is different. Similarly, in the Dubai complex, basic data on the Dubai/Brent Swaps market or the inter-month Dubai swaps are not publicly available though the volumes and open interest of Dubai swaps cleared through the exchanges are published. Transparency in the futures markets at least when it comes to prices, open interest and traded volumes is relatively well established. The futures market generates a set of prices throughout the day which are instantaneously transmitted through a variety of channels increasing price transparency. On the other hand, a detailed description of the participants in the futures market and the identity of counterparties to a futures contract are not made publicly available although the exchange and regulators via the exchange do have detailed data for futures markets on these areas. This is in contrast to the OTC market where the identities of counterparties to a transaction are known. Some market players place a high premium on such information and thus prefer to conduct their operations over the counter.

The third dimension of transparency relates to the extent to which assessed prices are accurate and are reached through a transparent and efficient process. There are two aspects to this issue. The first relates to the structural features of the oil market trading which impose certain constraints on these agencies' efforts to report deals and identify the oil price. As mentioned before, traders are under no obligation to report prices; it is not always feasible to verify reported deals; in opaque and unregulated markets, PRAs may need to rely on their evaluation of market conditions of specific crudes to reach an 'intelligent' price assessment. Thus, an important element of price transparency is the ability of PRAs to collect reliable information in imperfect and often illiquid markets and analyse the information in an efficient and objective manner. The second aspect is linked to the internal operations of PRAs. As discussed above, the methodologies used to assess the oil price differ considerably across agencies. Their access to information and the type of data used in their assessment process vary across PRAs and across markets. The procedures applied within each of the organisations to ensure an efficient price discovery process differ as these are internally driven and are not subject to external regulation or supervision. Thus, the degree of price transparency is very much interlinked to the activities of PRAs and the reporting standards and other procedures that they internally set and enforce.

9. Conclusions

Based on the above analysis of the current international crude oil pricing system, it is possible to draw the following conclusions:

- Markets with relatively low volumes of production such as WTI, Brent, and Dubai-Oman set the price for markets with higher volumes of production elsewhere in the world but with fewer or none of the commonly accepted conditions to achieve an acceptable 'benchmark' status. So far the low and continuous decline in the physical base of existing benchmarks has been counteracted by including additional crude streams in an assessed benchmark. Such short-term solutions though successful in alleviating the problem of squeezes should not distract observers from some key questions: What are the conditions necessary for the emergence of successful benchmarks in the most liquid market? Would a shift to assessing price to these markets improve the price discovery process? Such key questions remain heavily under-researched in the energy literature and do not feature in the producer-consumer dialogue. The emergence of the non-OECD as the main source of growth in global oil demand will only increase the importance of such questions. Doubts about the suitability of Dubai as an appropriate benchmark for pricing crude oil exports to Asia have been raised in the past (Horsnell and Mabro, 1993). This raises the question of whether new benchmarks are needed to reflect more accurately the recent shift in trade flows and the rise in importance of the Asian consumer.
- PRAs play an important role in assessing the price of the key international benchmarks. These assessed prices are central to the oil pricing system and are used by oil companies and traders to price cargoes under long-term contracts or in spot market transactions; by futures exchanges for the settlement of their financial contracts; by banks and companies for the settlement of derivative instruments such as swap contracts; and by governments for taxation purposes. PRAs do not only act as 'a mirror to the trade'. In their attempt to identify the price, PRAs enter into the decision-making territory. The decisions they make are influenced by market participants and market structure while at the same time these decisions influence the trading strategies of the various participants. New markets and contracts may emerge to hedge the risks that emerge from some of the decisions that PRAs make. The accuracy of price assessments heavily depends on a large number of factors including the quality of information obtained by the RPA, the internal procedures applied by the PRAs and the methodologies used in price assessment.
- The assumption that the process of identifying the price of benchmarks in the current oil pricing system can be isolated from financial layers is rather simplistic. The analysis in this report shows that the different layers of the oil market are highly interconnected and form a complex web of links, all of which play a role in the price discovery process. The information derived from financial layers is essential for identifying the price level of the benchmark. One could argue that without these financial layers it would not be possible to 'discover' or 'identify' oil prices in the current oil pricing system. In effect, crude oil prices are jointly co-determined and identified in both layers, depending on differences in timing, location and quality.
- Since physical benchmarks constitute the basis of the large majority of physical transactions, some observers claim that derivatives instruments such as futures, forwards, options and swaps derive their value from the price of these physical benchmarks i.e. the prices of these physical benchmark drive the prices in paper markets. However, this is a gross over-simplification and does not accurately reflect the process of crude oil price formation. The issue of whether the paper market drives the physical or the other way around is difficult to construct theoretically and test empirically in the context of the oil market.

- The report also calls for broadening the empirical research to include the trading strategies of physical players. The fact remains though that the participants in many of the OTC markets such as forward markets and CFDs which are central to the price discovery process are mainly 'physical' and include entities such as refineries, oil companies, downstream consumers, physical traders, and market makers. Financial players such as pension funds and index investors have limited presence in many of these markets. Thus, any analysis limited to non-commercial participants in the futures market and their role in the oil price formation process is incomplete.

- The analysis in this report emphasises the distinction between trade in price differentials and trade in price levels. We postulate that the level of the price of the main benchmarks is set in the futures markets; the financial layers such as swaps and forwards set the price differentials depending on quality, location and timing. These differentials are then used by oil reporting agencies to identify the price level of a physical benchmark. If the price in the futures market becomes detached from the underlying benchmark, the differentials adjust to correct for this divergence through a web of highly interlinked and efficient markets. Thus, our analysis reveals that the level of oil price, which consumers, producers and their governments are most concerned with, is not the most relevant feature in the current pricing system. Instead, the identification of price differentials and the adjustments in these differentials in the various layers underlie the basis of the current oil pricing system. By trading differentials, market participants limit their exposure to risks of time, location grade and volume. Unfortunately, this fact has received little attention and the issue of whether price differentials between different markets showed strong signs of adjustment in the 2008-2009 price cycle has not yet received its due attention in the empirical literature.

- But this leaves us with a fundamental question: what factors determine the price level of an oil benchmark in the first place? The crude oil pricing system and its components such as the PRAs reflect how the oil market functions: if oil price levels are set in the futures market and if participants in these markets attach more weight to future fundamentals rather than current fundamentals and/or if market participants expect limited feedbacks from both the supply and demand side in response to oil price changes, these expectations will be reflected in the different layers and will ultimately be reflected in the assessed price. The adjustments in differentials are likely to ensure that these expectations remain anchored in the physical dimension of the market.

- Transparency in oil markets has more than one dimension. Although improving transparency in the physical dimension of the market is key to understanding oil market dynamics and enhancing the price discovery function, our analysis shows that transparency in the financial layers surrounding the physical benchmarks is as important. In this regards, it is important to emphasize three dimensions to the transparency issue. First, obtaining regular and accurate information on key markets is not straightforward and depends largely on the willingness of PRAs to release or share information. Second, the degree of transparency varies considerably within the different layers in the Brent, WTI and Dubai-Oman complexes as well as across benchmarks. The third dimension of transparency relates to the extent assessed prices are accurate and are reached through a transparent and efficient process. There are two aspects to this issue. The first aspect relates to the structural features of the oil market trading which impose certain constraints on these agencies' efforts to report deals and identify the oil price. The second aspect is linked to the internal operations of PRAs. Thus, the degree of price transparency is very much interlinked to the activities of PRAs and the reporting standards and other procedures that they internally set and enforce.

The current oil pricing system has now survived for almost a quarter of a century, longer than the OPEC administered system did. While some of the details have changed, such as Saudi Arabia's decision to replace Dated Brent with Brent futures price in pricing its exports to Europe and the more recent move to replace WTI with Argus Sour Crude Index (ASCI) in pricing its exports to the US, these changes are rather cosmetic. The fundamentals of the current pricing system have remained the same since the mid 1980s i.e. the price of oil is set by the 'market' with PRAs using various methodologies to reflect the market price in their assessments and making use of information generated both in the physical and financial layers surrounding the global benchmarks. In the light of the 2008-2009 price swings, the oil pricing system has received some criticisms reflecting the unease that some observers feel with the current system.[111] Although alternative pricing systems can be devised (at least theoretical ones) such as bringing back the administered pricing system or calling for producers to assume a greater responsibility in the method of price formation by removing destination restrictions on their exports, or allowing their crudes to be auctioned,[112] the reality remains that the main market players such as oil companies, refineries, oil exporting countries, physical traders and financial players have no interest in rocking the boat. Market players and governments get very concerned about oil price behaviour and its global and local impacts, but so far have showed much less interest in the pricing system and the market structure that signalled such price behaviour in the first place.

[111] See, for instance, Mabro (2008). Mabro argues that 'the issue is whether the current price regime for oil in international trade is an appropriate one. Nobody questions it because the vested interests in maintaining it are extremely powerful. Banks and hedge funds are wedded to it. Some of the major oil companies have trading arms that operate in these derivative markets like financial institutions. Their trading profits are substantial. OPEC accepted it because they thought that it would protect them from blame. It didn't. And the question always asked is: What is the alternative? I will simply say that no alternative will ever be found if nobody is looking for one.'

[112] See for instance, Luciani (2010).

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