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# The Fundamentals Underlying Oil and Natural Gas Derivative Markets

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## Abstract

What determines the range and boundaries of energy derivative markets? Why is the oil futures trade dominated by contracts on two grades and locations when the global trade encompasses many grades and locations? Should we expect change in the near future? We review research on the establishment and performance of energy derivative markets, focusing on the two major energy commodities: oil and natural gas. For both commodities, trade in derivatives arose at the conclusion of a historical process in which production along the value chain that had been coordinated by vertically integrated companies or similar institutional structures switched to being coordinated through markets. Consequently, much of the research reviewed here is about the structural changes that made it possible for markets to assume this role. This review encompasses research into the price discovery function, which determines how many successful futures contracts are needed for each commodity.

# 1. INTRODUCTION

What determines the range and boundaries of energy derivative markets? Why is the oil futures trade dominated by contracts on two grades and locations, when the global trade encompasses many different grades of oil shipped from, through, and to many other locations? One of the two benchmark futures grades is West Texas Intermediate (WTI), delivered into Cushing, Oklahoma, a confluence of pipelines in the US interior. The other is Brent crude, produced from the North Sea and traded as tanker cargoes out of that region. Although there exist a select few derivative contracts associated with other locations and grades, including a blend from the Persian Gulf, trade in these is small. Countries in the Asia Pacific region now account for 35% of global oil consumption (BP 2016). Nevertheless, there is no significant derivative linked to a delivery point in the region. Although Russia is a major oil exporter, efforts to develop a futures contract linked to the country's Urals blend have, so far, not met with success. Why? Should we expect this situation to change in the near future?

We review here research on the establishment and performance of energy derivative markets, focusing on the two major energy commodities: oil and natural gas. For both oil and natural gas, trade in derivatives arose at the conclusion of a historical process in which production along a value chain that had been coordinated by vertically integrated companies or similar institutional structures switched to being coordinated through markets in the physical commodities. Consequently, much of the research reviewed here is about the structural changes that made it possible for markets to assume this role. In both cases, once markets in the physical commodity gained their central role, markets in derivatives quickly arose and became the preferred location for price discovery. This review encompasses research into this price discovery function, which is pertinent to answering the question of how many successful futures contracts are needed for each industry.

This review complements earlier reviews of commodity derivative markets by, e.g., Rouwenhorst & Tang (2012), who discuss these markets from the perspective of the investor, Cheng & Xiong (2014), who discuss how financial investors in commodities affect risk sharing and price discovery, and Parsons (2013b), who covers the corporate use of derivatives to hedge oil price risk. Here the focus is instead on the link between the industrial structure of a given energy market and the role of futures trading. Whereas the literature reviewed by Cheng & Xiong (2014) discusses how financial investors perturb price discovery in futures markets, the literature reviewed here discusses the fundamentals underlying that price discovery role.

The term "derivatives" encompasses exchange-traded futures and options as well as the over-the-counter (OTC) market in swaps and many other instruments. Exchange-traded futures have generally played a leading role in energy markets of all kinds, which is a contrast to some other sectors of the derivatives world, such as interest rates and credit, where OTC trade has dominated. Consequently, this review focuses largely on the development of trade in futures. However, it gives attention to OTC markets where that is essential to appreciating the proper place of the trade in futures.

Section 2 covers the oil market and Section 3 covers the natural gas market. Both sections begin with a discussion of the historical industry restructuring that shifted coordination along the value chain to markets in the physical commodity, provide details on the historical rise of futures markets, and conclude with discussion on the potential evolution in futures markets.

# 2. OIL

## 2.1. Industry Restructuring

An active spot market in crude oil is a prerequisite for futures trade, and this prerequisite was lacking at the start of the 1970s. At that time, global flows in crude oil were controlled by the so-called Seven Sisters: Exxon, Mobil, Texaco, SoCal (Chevron), Gulf, Royal Dutch/Shell, and British Petroleum (BP). Much of their control was based on concessionary access to resources in oil-producing countries, including those organized into the Organization of Petroleum Exporting Countries (OPEC). Economically, concessionary access is comparable to direct ownership. As Adelman (1972) documents, this oligopoly was able to exercise market power, which, along with the favorable terms of the concessions, assured the companies high margins. The value chain, from production through transportation, refining, and marketing, was controlled as a vertically integrated operation. Where independents operated downstream—for example as refiners—their dealings with the suppliers were managed through long-term contracts or arrangements.

A global market in oil developed during the 1970s and 1980s out of a transformation of the global industry, as detailed by Mohnfeld (1984) and Verleger (1987, 1988). Between 1973 and 1982, through a number of actions involving nationalizations and renegotiations of concession terms, the producing countries took control of their resources and radically reversed the pricing relationship with the Seven Sisters. This included the two dramatic price hikes associated with the 1973–1974 oil embargo and the 1979–1980 oil crisis. The total amount of global oil controlled by these seven companies fell from 30.0 million barrels per day (mbd) in 1973 to 15.2 mbd in 1982, a drop of 14.8 mbd. This translated into a drop in their share of the production outside the Communist bloc from 62% to 37%. In 1972, 85% of the oil they controlled was so-called equity oil, which earned them the highest margins. By 1982 this had fallen to 43% of the now smaller total, or 6.7 mbd. Per Verleger (1987, p. 168), "The majors had been replaced by a large number of medium sized oil companies, producing-country oil companies, consuming-country oil companies, and traders."

This disruption to the old industry structures dramatically changed patterns of competition and trade, enabling the development of active spot market trading. Where previously the Seven Sisters had carefully managed production and their own refinery capacity, the uneven pattern of nationalizations and renegotiation created imbalances in crude production and refinery capacities. In addition, the shift of pricing control to the producing countries undermined the profitability of the long-term relationships through which the Seven Sisters had previously supplied other refiners with crude. Finally, the pricing power newly exercised by OPEC became a spur to develop new, non-OPEC sources of production in the North Sea, Mexico, Alaska, Malaysia, and elsewhere. OPEC's share of production outside the Communist bloc and North America declined from 84% in 1969 to 59% in 1983. The Seven Sisters now competed with other companies for these new resources, creating a much more liquid market along the supply chain. Altogether, the decade produced a dramatic rupture in the vertical integration along the value chain and an increased role for spot market trading in crude and products globally. Mohnfeld (1984) reports that the volume of spot crude supplies increased from a level of 1–3% in 1979 to an estimated one-third of crude oil traded in 1983. At the same time, the price of crude oil became much more volatile, as documented by Verleger (1987) and Dvir & Rogoff (2009). This increased the potential need for well-functioning spot and futures markets.

In parallel with these changes to global trade, the 1970s and 1980s saw a reshaping of the dynamics within the US industry that also promoted a shift to an active spot market, as described by Yergin (1991) and Dvir & Rogoff (2009). Throughout the mid-century, US domestic production and prices had been subject to both federal and state regulation, and imports had been managed through a complex and changing system of quotas. This stemmed from the 1930 discovery of the giant East Texas Oil Field and the sudden availability of a cheap supply that dramatically depressed the price in the midst of the Great Depression. As it happened, the excess supply had largely dissipated by the start of the 1970s. For the first time since World War II, the Texas Railroad Commission allowed production at 100% of capacity in 1971. This new domestic situation intersected with the new global context. Once the OPEC nations seized control of their resources and managed their capacity to maintain a high global price, North America became one of the many sources of competitive supply outside of OPEC. In January 1981, the United States decontrolled all prices in crude oil and products. The changing market structure and changing dynamics in supply and demand brought changes in marketing practices. Verleger (1987, 1988) documents the shift from a system of posted prices to regularly updated quotations of spot prices in various markets and for various products. The growth of spot market trading manifested itself in a sudden explosion of alternative sources for price data and intensive competition among these sources to deliver more data feeds on an ever faster basis. From refineries to final customers, such as airlines and gas stations, the room for independent operators and the scope of competition expanded suddenly. The vertically integrated companies started treating each of their business units as distinct profit centers.

Another particularly important development in the changing global context is the creation of the Brent market associated with the North Sea oil fields. Although the presence of oil had been documented decades earlier, and although certain key discoveries had been made in the 1960s, the oil price hike of 1973–74 suddenly made it profitable to accelerate development. Production from the UK shelf multiplied more than sixfold between 1976 and 1982, as related by Atkinson, Brooks & Hall (1983). The process continued in later years and elsewhere in the North Sea. This produced another important stream of crude oil feeding into the global marketplace, which competed with OPEC production. As described by Weiner (1989), an informal market in tanker cargoes out of the region developed, known as the Brent market, complete with standardized terms and trading conventions, and prices in this market quickly became a well-monitored benchmark for the industry.

## 2.2. Crude Oil Derivatives

Modern futures markets in crude oil and refined products began to appear in the 1970s, as recounted by Dale (1991) and Simkins & Jia (2016).[1] The New York Cotton Exchange established a propane contract in 1971. Although it was not remarkably successful at first, the contract survived and was later sold to the New York Mercantile Exchange (NYMEX), which is now owned by the CME. This was followed by a failed attempt at a futures contract for delivery of Oklahoma crude and another failed attempt at a futures contract for delivery of crude into Rotterdam. Success finally came with NYMEX's 1978 introduction of a futures contract on heating oil delivered into New York Harbor. Remarking on this success in 2002, the US Energy Information Administration (EIA) (2002, pp. 23–24) reported that "trading volume in a successful contract can climb dramatically. For example, the annual trading volumes of the No. 2 heating oil contract grew from 25,910 in 1978 to more than 932,000 in 1980, to 5.7 million in 1989, and to a record 9.6 million in 2000." This was followed by NYMEX's 1983 introduction of the WTI crude oil futures contract. Dominguez (1989) notes that, at its launch, volume in the WTI futures contracts averaged less than 1,000 contracts daily (less than 1,000,000 barrels), but by the end of 1987, volume exceeded 18,000 contracts daily. In 2015, average daily volume totaled nearly 600,000 contracts. In 1985, NYMEX added futures contracts in gasoline. In 1994, NYMEX added a residual fuel oil contract as well as a crack spread contract. In later years, as the portfolio of traded physical products shifted, available futures contracts shifted, too, now including biofuels and petrochemicals.

[1] Weiner (2003) documents that the nineteenth-century United States boasted at least 20 exchanges where crude oil was traded before the extreme consolidation of the industry by the Standard Oil Trust eliminated them.

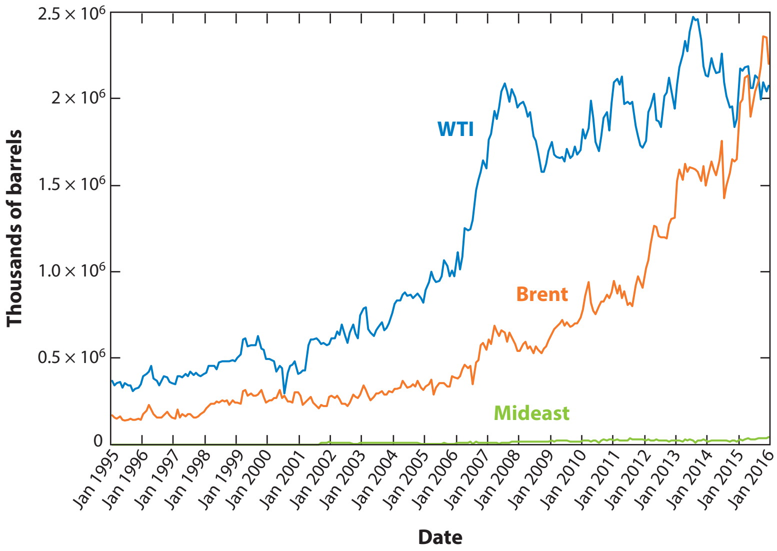


**Figure 1**

Total open interest across all futures contracts in three types of crude oil. WTI (*blue*) aggregates open interest on NYMEX's WTI contract and open interest on ICE's copycat WTI contract. Brent (*orange*) aggregates open interest on ICE's Brent contract and open interest on NYMEX's copycat Brent contract. Mideast (*green*) aggregates open interest on the Dubai Mercantile Exchange's Oman contract and TOCOM's Middle East Crude Oil contract. Figure data are from Bloomberg. Abbreviations: ICE, Intercontinental Exchange; NYMEX, New York Mercantile Exchange; TOCOM, Tokyo Commodity Exchange; WTI, West Texas Intermediate.

Since the successful establishment of futures contracts on crude oil and oil products in the 1980s and 1990s, the markets have continued to grow. **Figure 1** shows that total open interest in the WTI more than quadrupled from 1995 through 2015.

The UK's Brent market also evolved its own derivatives in the 1980s and 1990s. These were initially extrapolated from the forward physical market, in which the industry developed tools for financial settlement of physical delivery obligations. These obligations included a process for canceling offsetting transactions that developed in the so-called daisy chain of forward shipments owed between different companies. In 1988, the International Petroleum Exchange (IPE), located in London, took this a step further and established a futures contract in Brent, complete with all of the usual institutional features, including marking to market, margining, and central clearing. The contract is now owned by the Intercontinental Exchange (ICE), and the scale of trading in the Brent futures contract has recently overtaken that of the WTI contract. As seen in **Figure 1**, the open interest is also comparable across the two crudes.

Derivative trade in crude oil is overwhelmingly dominated by contracts on WTI and Brent. In fact, the exchanges that pioneered each of the contracts (NYMEX for WTI and ICE for Brent) now each offer a copycat contract on the other product: ICE offers a WTI contract tied to the price on NYMEX, and NYMEX offers a Brent contract tied to the price on the ICE exchange. The next most important set of contracts are those linked to the price of crude oil exported from the Persian Gulf, much of which is destined for East Asian markets. The Tokyo Commodity Exchange (TOCOM) has listed one of these contracts, priced in yen, since 2001. The Dubai Mercantile Exchange has listed another, priced in US dollars, since 2007. Nevertheless, the futures trade in these Mideast crudes remains very limited, as seen in **Figure 1**. Total open interest in these contracts has grown to only about 2% of trade in WTI.

Other derivative contracts are less significant still. For example, exchanges currently offer futures and basis contracts on a few other North American benchmark prices—such as Louisiana Light Sweet and Canadian Heavy—but with very limited trade. Since 2005, the Multi Commodity Exchange of India Ltd. has listed a crude oil futures contract that is a mirror of NYMEX's WTI contract. It is priced in rupees and is supposedly deliverable in Mumbai, but in reality it provides an opportunity for Indian investors to speculate on the WTI price. Since 2000, as Chinese demand for oil has grown dramatically, interest has been expressed in developing a local China-based crude oil futures contract. A fuel oil futures contract has been trading on the Shanghai Futures Exchange since 2004, and there are regular announcements about coming crude oil futures contracts.[2] However, the opening of actual trading has been regularly postponed. The St. Petersburg International Mercantile Exchange (SPIMEX) is in the process of launching a futures contract on Russian Urals-grade oil.

In addition to exchange-traded futures and options on crude and refined products, there is a large OTC derivative market. Unfortunately, prior to the 2007–2008 financial crisis, little information was publicly available about this segment of derivative trade. With the passage of the Dodd–Frank Act in the United States and related legislation in other countries, many transactions must now be reported to data repositories and to national regulatory authorities such as the US Commodity Futures Trading Commission (CFTC). This new stream of data is not yet comprehensive, and what is available exhibits many quality problems. Nevertheless, it promises new insight about the size and structure of the financial market beyond the traditional exchange-traded futures and options contracts. For example, a recent report from economists at the CFTC (Mixon, Onur & Riggs 2016) shows that open interest in WTI-linked OTC derivatives in the United States is roughly 80% of the open interest in the WTI exchange-traded futures and options market in the United States. Therefore, incorporating the OTC market into the picture nearly doubles the open interest. (This includes some double counting, as a portion of OTC dealers' exposures are brought to the futures market in order to hedge the dealers' books.) The data show that the two portions of the market exhibit some important similarities and differences. Commercial end-users (including producers, processors, merchants, and customers) hold net short positions in both portions of the market. Financial end-users (including investment funds and hedge funds but not derivative dealers) hold net long positions in both. The maturity structure of the open interest is roughly the same across the two. However, the open interest of commercial end-users is more heavily weighted to the OTC market, whereas the open interest of financial end-users is more heavily weighted to the futures and options market. The data are limited to US swaps on WTI. Derivatives on Brent and many smaller markets can also be traded in the OTC market, but we still have almost no data on these.

With the establishment of liquid trade in futures, price discovery quickly moved from the spot market to the futures market, i.e., from the market in the physical product to the financial market, as documented by Schwarz & Szakmary (1994). Bekiros & Diks (2008) and Shrestha (2014) find evidence for price discovery in both the futures and spot markets. Just as importantly, the futures market provides price discovery all along the term structure. A long literature describes how the term structure in commodities reflects the supply and demand for intertemporal shifts in production, most obviously through storage, but also through changes in production. The literature dates

[2]Tang & Zhu (2016) show how capital controls in China create a demand for using commodities as collateral, which affects pricing, convenience yield, and inventories; the Shanghai fuel oil futures contract is one of the contracts analyzed.

back to Kaldor (1939), Working (1949), Telser (1958), and Brennan (1958). Among the many recent contributions are those of Williams & Wright (1991); Litzenberger & Rabinowitz (1995); Routledge, Seppi & Spatts (2000); Kogan, Livdan & Yaron (2005); Carlson, Khoker & Titman (2007); and Gorton, Hayashi & Rouwerhorst (2013). This theory has been integrated with the hedging pressure theory, which dates back to Keynes (1930), in work reviewed by Acharya, Lochstoer & Ramadorai (2013). Storage and production models emphasize the equilibrium mean-reverting process component of commodity prices, which is impounded into the term structure of futures prices.

Simple statistical models of crude oil prices, such as those of Schwartz & Smith (2000) and Cortazar & Schwartz (2003), put the half-life of these mean-reverting shocks at less than 1 year. This makes sense of the concentration of futures trading in the shorter-maturity contracts, as these are the contracts that reflect temporary variations in supply and demand that are critical to adapting inventories, transport, and short-term production plans. Initially, this meant 1-, 2-, and 3-month contracts with virtually no trade in later months. Today, although contracts are available 9 years forward, approximately 78% of the open interest is concentrated in maturities of less than 1 year. Another 16% of the open interest is in maturities of 1–2 years, 4% in maturities of 2–3 years, and the remaining 2% in maturities longer than 3 years (Mixon, Onur & Riggs 2016). It should be noted that because the scale of trade is much greater now than in the early years of trading, even contracts with maturity out to 4 years have more open interest and liquidity than did the most liquid 1-, 2-, and 3-month contracts as recently as 2000.

## 2.3. Further Development

We now return to the question that opened this review: What determines the range and boundaries of energy derivative markets? In particular, how many crude oil futures contracts should we expect the market to produce? With the growth of East Asia as a destination for global crude oil deliveries, is a futures contract linked to East Asia necessary?

Regarding the last question, the answer from the literature is, in my opinion, no. In order for an East Asia futures contract to be successful, two conditions would need to be met. First, an active local spot trade is a precondition for any local futures contract. Second, the local price would have to be an important contribution to the global price discovery process. Neither condition is yet met.

In the 1980s and 1990s, the lack of any futures contract linked to a local spot price reflected, in part, the readiness of Japan, as the major importing country, to do business through long-term contracts with its Middle East suppliers, foreclosing the creation of an active spot market in East Asian deliveries. China, too, has chosen to manage its own production and imports through vertical arrangements that have foreclosed a major role for spot trade, with some modest exceptions. There are some signs that both countries are considering changes, but until a vibrant spot market is developed, there is no possibility for a meaningful futures trade.

The second condition is likely to be a more permanent obstacle to the success of an East Asian futures contract. The answer to the question, "How many crude oil futures contracts are needed?" appears to be "one", or at least "one main one". This answer comes out of an old debate about the structure of global trade in oil. Adelman (1984, p. 5) staked out one side of the debate, asserting that "the world oil market, like the world ocean, is one great pool." This is the rallying cry of those who believe in the law of one global price for crude oil, with variations arising across locations because of transportation costs and variations arising across grades of oil because of processing costs. Weiner (1991) staked out a competing view, arguing for a high degree of regionalization in prices and price adjustments. The two positions are sometimes presented as mutually exclusive, with the ensuing literature supporting one or the other. For example, Bentzen (2007) uses cointegration tests and error correction model estimation to support the one great pool viewpoint, and Dai et al. (2015) provide an updated statistical analysis in favor of some regionalization. In fact, the two viewpoints are not mutually exclusive. The varying crude oil prices at different locations and for different grades may be driven by a single primary factor that reflects an evolving global supply and demand balance, while simultaneously being driven by a set of secondary factors reflecting local perturbations around that balance that cannot be immediately arbitraged but that also are not lasting. Fattouh (2010) presents an analysis of price differentials at various locations, including both spot and futures prices, consistent with this integrated view.

This is pertinent to the structure of futures markets because it speaks to how many different regional futures contracts are needed. Insofar as there is an identifiable global supply and demand balance, a single futures contract could conceivably be sufficient for providing the necessary price discovery and hedging services. If markets are fully regionalized, then it may be necessary to have multiple contracts. Or, if markets are globalized in the long run, but there are temporary, localized price perturbations, then one contract may be the focal point for discovery and hedging of the global factors, with local contracts being necessary only to provide discovery and hedging of the basis differentials. In that structure, the global benchmark would have liquidity out to longer maturities, whereas liquidity for the local contracts would be limited to short maturities.

Thus, the two lead contracts, WTI and Brent, are battling to be the single global benchmark. Kao & Wan (2012) show that throughout much of its history, the WTI contract was the point of global price discovery in the sense of Hasbrouck's (1995) information shares model. In recent years, however, transportation bottlenecks in North America have isolated the delivery point in Cushing, Oklahoma from the global market, reversing the usual basis and, more importantly, disrupting the price change correlations, as studies by Fattouh (2010), Buyuksahin et al. (2013), and Liu, Schultz & Swieringa (2015) have documented. According to many in the industry, this has made WTI a broken benchmark. Gilje & Taillard (2016) demonstrate how this has impaired the financial choices and performance of even Canadian oil producers that have relied on using the WTI contract as a hedge. Kao & Wan (2012) find that WTI has lost much of its price discovery role as a result of these changes, although this is disputed by Elder, Miao & Ramchander (2014).

Other futures contracts defined on other locations can only supplement the global price discovery role filled by one of the dominant contracts. Research by Kaufmann & Ullman (2009) uses the WTI and Dubai contracts to illustrate the two-factor structure: They find that the far-month trading of WTI reveals one factor and the short-month trading in Dubai reveals another factor. In this two-factor structure, one contract is the primary vehicle for price discovery and the other supplements it. Only a small amount of trade in the second contract is needed, as evidenced by the small open interest in the Dubai and related contracts, at approximately 2% of the WTI contract. Many failed efforts have been made over the years to establish supplemental contracts. Indeed, as the WTI contract began to lose hedging effectiveness for Canadian producers, in 2013 the NYMEX launched a futures contract defined on Canadian crude oil production, but it failed. If an East Asian futures contract were to be established, it would most likely play a subsidiary role, as does the Dubai contract. It is not clear there is a need for another subsidiary contract. The answer to this depends upon the uniqueness of price innovations in Asian benchmark prices.

## 3. NATURAL GAS

### 3.1. Industry Restructuring

The development of an active spot market in natural gas has been a purposeful objective of regulatory restructuring. This happened first in both the United States and the United Kingdom. More recently, it has been spreading, fitfully, throughout continental Europe.

The history of US regulation preceding the eventual establishment of a well-regulated spot market is described by MacAvoy (2000) and Joskow (2013). A good starting point is the Natural Gas Act of 1938, under which the United States regulated the natural gas market using a cost-of-service model. Subsequent decades saw the expanded use of natural gas and the correspondingly gradual expansion of the US network of pipelines. However, significant stresses appeared in the 1970s and 1980s. The low regulated prices were already producing shortages when the oil price shocks of 1973–1974 and 1979–1980 suddenly incentivized even more customers to demand natural gas, creating large shortages. Then, just as the regulatory system was adapted to encourage additional production under the protection of long-term purchase contracts, oil prices started their dramatic fall in 1981–1986, creating a surplus of gas supply known as the take-or-pay contract bubble. More regulatory adjustments ensued. The key resolution came in a series of orders from the Federal Energy Regulatory Commission (FERC) together with the Natural Gas Wellhead Decontrol Act of 1989, which pushed for open access to the pipelines, including an unbundling of transportation and gas purchases as well as other pipeline services, and the right to resell gas. The FERC also specifically encouraged the creation of pipeline trading centers. Among these was the Henry Hub, created in 1988 and located in the state of Louisiana, along the Gulf Coast producing area and connecting more than a dozen pipelines delivering natural gas to markets up the East Coast and in the Midwest of the United States. This gave the Henry Hub access to a diversity of suppliers and buyers, which helped to assure a competitive spot market in the physical product.

This regulatory restructuring quickly produced changes in commercial practice and market prices. Previously, US natural gas markets had been regionally segmented. Under the old regulatory rules, the different regional histories of contracting translated into different prices. After the reform, companies sought to arbitrage price differentials across regions, and local spot prices began to reflect short-run supply as well as short-run demand factors such as seasonality. De Vany & Walls (1994, p. 78) document that in the 5 years from 1985 to 1989, the number of locations reporting spot prices "grew from a handful to more than 50." Price differentials between regions declined and the correlation between the prices in different regions increased, reflecting the creation of a national market with locational variation defined by shipping costs. Doane & Spulber (1994) document the shift in purchasing to unbundled gas and transport services, as well as the increasing share of spot deliveries, which went from approximately 0% in 1982 to more than 55% in 1987. They document increasing correlations between price changes in different regions along with other evidence of an increasingly national market. Under the new system, regional differences primarily arise where transport capacity becomes constrained. Marmer, Shapiro & MacAvoy (2007) and Brown & Yucel (2009) document some returning segmentation during the 1990s as increases in consumption pressed against pipeline capacity constraints in certain locations. More recently, as gas production shifts from the traditional producing regions to new regions with shale gas resources, we may see some bottlenecks loosened and new bottlenecks created, as suggested in modeling by Kleit et al. (2015).

The United Kingdom's transition is described by Juris (1998), McDaniel & Neuhoff (2004), Price (2005), and Heather (2010). Since 1949, the gas industry had been operated as a national monopoly, British Gas. The 1982 Oil and Gas Act took a first small step toward enabling industrial customers to obtain gas from competing suppliers. In 1986, British Gas was privatized, and all large industrial customers were granted the right to contract with independent suppliers and use the national pipeline network to receive their gas. However, this did not prove very effective in creating actual competition in supply. Over the ensuing years, the government took several more incremental steps toward opening up supply to competition, ultimately leading to the Gas Act of 1995 and the 1997 breakup of British Gas into a gas production and supply company on the one hand and a gas transport company on the other. This facilitated competitor access to pipelines and accelerated the growth of competition in supply. British Gas's share of supply fell from 80% in 1992 to 33% by the end of 1996. The Gas Act of 1995 established a process for the daily balancing of supply by shippers across the entire National Transmission System. In addition, it created the National Balancing Point (NBP), which is a pricing convention for trading offsetting quantities into and out of the system at various locations; this is also known as a virtual hub. This evolved into the benchmark spot market in physical gas, and the NBP price for such trades is the benchmark price.

Continental Europe, too, has recently been moving to reduce the role of long-term vertical relationships in the natural gas industry and to promote the role of spot market trading. However, this is still a work in progress, and much remains to be done. Belgium and the Netherlands, which moved forward relatively quickly, now host vital spot markets at, respectively, the port of Zeebrugge and the Title Transfer Facility (TTF), another virtual hub. In 1998, the Interconnector pipeline opened, connecting Zeebrugge to the United Kingdom, and these two spot markets now play a strong role in arbitraging between the continent and the United Kingdom. Other continental European countries, including France, Germany, Italy, and Eastern European countries, have moved less quickly. Heather (2012) describes the opening of new trading hubs in France at the Point d'Échange de Gaz (PEG) Nord and Sud and in Germany at Gaspool and NetConnect Germany (NCG), although these are much less liquid than Zeebrugge and TTF. A large portion of European supply continues to be governed by long-term contracts between major suppliers such as Gazprom and local distribution utilities that bundle supply to pipeline transportation and that restrict resale. European competition authorities and gas regulators are working to eliminate such restrictions and to assure open access and unbundled supply. Prices in these long-term contracts are usually linked to oil, although, as the spot trade at natural gas hubs becomes more significant, contracts can begin to link to spot natural gas prices at local hubs. According to Stern (2014, p. 45), in 2011–2012, "45% of the gas sold in Europe was based on hub, rather than oil-linked prices," and this percentage is increasing significantly.

In contrast, the East Asia region has not developed any active spot market in natural gas. A study into the potential for a natural gas trading hub in Asia by the International Energy Agency (IEA) (2013) points out that the region is physically fragmented and has no highly interconnected high-pressure pipelines like those in North America and Europe.

In previous decades, the largest consumer of natural gas was Japan, where all of the supply arrived as shipments of liquified natural gas (LNG). These shipments were made under rigid long-term contracts negotiated with producer countries. The local gas and power utilities that have been the buyers of most of the gas and that control the gas transport and distribution system have operated under a regulatory regime that made little room for a competitive spot trade. Although there are many gas-consuming companies within Japan that could provide a competitive foundation for a wholesale market, the country has encouraged them to negotiate collectively with supplier countries in order to get better pricing. For example, in 2010, four utilities operated as the middlemen for nearly 71% of total LNG deliveries. Moreover, once supply is landed at an LNG terminal, there are no rights of open access. Natural gas distribution and sales are run by vertically integrated utilities. In addition, the domestic pipeline infrastructure is not adequately interconnected to enable significant arbitrage.

Recently, China has overtaken Japan as the largest consumer, but it, too, has not utilized a competitive spot market. The domestic market has been dominated by three state-owned companies, and one company owns 80% of the pipeline network. There has been no right of third-party access or ability to resell gas. Prices have been firmly regulated. However, as noted by Shi & Variam (2015), China has recently taken steps toward a functioning wholesale market. A process of privatization is underway, together with mandates for unbundling transport from supply and for third-party access to the pipeline network and other assets. Domestic natural gas price regulations are being gradually reformed to reflect more accurately the current cost of imports (Paltsev & Zhang 2015). However, whether these de jure steps produce de facto third-party access is an open question. The right of access has been made provisional on there being spare capacity, and currently there is a severe shortage of capacity. With use increasing quickly and pipeline infrastructure lagging, it is not clear when spare capacity will exist unless further policy changes are pursued.

Some proponents of active spot trading in East Asia have directed attention away from individual domestic markets and toward the growing international trade in LNG shipments. Historically, LNG trade had been managed through rigid long-term contracts. This practice dates back to the first shipments to Japan in the 1960s. This trade requires substantial capital investments: liquefaction facilities at the source point, the train of LNG tankers, and regasification facilities at the destination. Therefore, the earliest investments in these facilities also demanded long-term contractual commitments between buyers and sellers. In addition, in the early years, the designs of these facilities were often customized from source to destination, so that shipments could not be easily repurposed to other destinations. In addition, sellers, especially in OPEC, imposed destination clauses that helped them exercise their market power and that limited the development of spot trade. Until recently, buyers, too, have been comfortable with trade structured through long-term contracts.

Several of these limits on wholesale LNG trade have been weakened over recent years. The expanded scale of LNG trade, which has multiplied the number of buyers and sellers, has also been accompanied by a larger fraction of shipments available on a spot basis (for an analysis of this factor in determining the viability of spot trade, see Parsons 1989). Japan's Fukushima disaster radically restructured its energy picture and increased its needs for natural gas above what had previously been planned for and contracted, which has been a powerful demonstration of the value of a flexible supply. The surprising availability of cheap supplies in the United States and the move to develop export facilities in the United States have also demonstrated the value of flexibility; Stern (2014, p. 47) writes that "a consequence of the US gas surplus was the conclusion, in 2012, of the first LNG export contracts from the Sabine Pass project priced on a Henry-Hub-plus basis." Taking note of this increase in spot LNG cargoes, in 2009, the energy news and information provider Platts developed its Japan Korea Marker (JKM), a price index calculated from a survey of spot cargoes into Japan and Korea.

China, too, has identified some possible value in encouraging spot trade in LNG shipments. Stern (2014) reports that China has announced plans to create a hub in Shanghai that would enable wholesale transactions at the point of import among a few key consuming provinces, importers, and storage facilities. There already exists a small amount of spot trade there, but it remains to be seen whether this will produce a robust wholesale market.

In parallel with this growing LNG trade, the IEA (2013) describes a developing network of pipelines interconnecting Malaysia, Thailand, Indonesia, Vietnam, and the city-state of Singapore. As these nations are also involved in the LNG trade, whether as suppliers or consumers, this improves the flexibility of the overall system. Indeed, the government of Singapore is actively pursuing the goal of becoming a hub for trade in LNG. The country has long been a regional hub for crude oil cargoes as well as oil products, so it is looking to extend its regional role to natural gas. Starting with the Gas Act of 2001, the Singaporean domestic market had already been liberalized, complete with unbundling of transport from supply and open access. The IEA (2013) notes that Singapore has expanded its terminal facilities and made them able to receive ships of various sizes, as well as adding additional storage capacity. Shi & Variam (2016) note that Singapore launched a spot price index in 2015.

### 3.2. Natural Gas Derivatives

As far back as 1984, NYMEX attempted to extend its success from the oil market into natural gas, but its proposal was dismissed by the CFTC on the basis that the underlying physical market at that time was not yet assuredly competitive enough at the necessary scale (Doane & Spulber 1994). By 1990, when NYMEX made its new proposal for a futures contract, the CFTC had become convinced that "the supply of gas deliverable to the designated interchange Henry Hub, Louisiana, was sufficiently large in both peak and demand periods to minimize the possibility of price manipulation or congestion" (Doane & Spulber 1994, p. 487). Brinkmann & Rabinovitch (1995) report that the new contract had the fastest takeoff of a contract in the history of NYMEX. It quickly became the benchmark price throughout the North American natural gas industry. Statistical work by Nicolau, Palomba & Traini (2013) and Shrestha (2014) demonstrates that price discovery happens through the futures market as opposed to the spot market.

In the 1990s, OTC derivative trading also became an important element of the US natural gas market. Enron was a major force for this, and several other trading companies operated in this terrain. However, financial trading in natural gas was briefly disrupted by several coincident events. These included Enron's bankruptcy and the related California electricity crisis. These also included revelations of significant manipulation of natural gas and electricity markets, including wash trades and churning designed to create the illusion of liquidity at key hubs, as documented by the FERC (2003). Parsons (2013a) relates how these events combined to create financial difficulties for several leading trading companies, which drove them to exit the trading business. The impact has not proved lasting. The lack of public data on the OTC market makes it impossible to have a clear picture of the relative size of the futures and OTC portions of the market. The limited preliminary data reported by Mixon, Onur & Riggs (2016) suggest that currently the OTC market dwarfs the futures market in natural gas. It would be natural to think that the OTC market has an important role in price discovery, but there are no studies on this, probably because of the lack of available data.

The development of derivative trading in the United Kingdom is described by Bossley (1999) and Heather (2010, 2012). A small OTC market in forward contracts developed around transactions into the National Transmission System using the NBP. This was followed in 1997 by establishment of a futures contract based on the NBP and traded on the IPE (now the ICE). The futures contract quickly established itself alongside the OTC market, although the OTC trade continued to have higher volumes. The UK OTC market, too, was briefly hurt by the Enron bankruptcy and related events, but like the US market it quickly recovered. In recent years, the share of the futures market has grown, but the OTC market remains larger.

In continental Europe, derivatives linked to prices on the emerging liquid spot markets are now available, with Zeebrugge and TTF being the most relevant. However, according to Heather (2012), much of the trade is OTC and it is not yet clear that there is much liquidity.

Until recently, there had been no meaningful natural gas derivatives traded in East Asia. The IEA (2013) takes note that in 2012, the Japanese government announced a consultation between the Ministry of Economy, Trade, and Industry and 18 companies (including power and gas utilities, trading companies, and financials) with the objective of creating a natural gas futures market. At the time, they had set a start date target of April 2014, but the launch has been repeatedly postponed and now stands at late 2017. It is difficult to see how this new target can be met. Without an underlying change in the organization of the physical trade in natural gas, it is impossible to imagine a successful futures market. In the past, there have been proclamations about the value of establishing an active wholesale market, as well as efforts at reform, but follow-through has been lacking. Many interests favor the current structure. It is possible that real changes will come about, as the energy policy situation in Japan is in significant flux after the Fukushima disaster. However, until those changes materialize, any talk of an active futures market is an example of putting the cart before the horse.

China has declared its intention to develop a natural gas futures contract, although this is properly anticipated as a later stage of a reform that first establishes an effective spot trade in physical gas, so it is reasonable to imagine this is a far-off prospect.

In 2012, the ICE exchange launched a swap contract (later converted to futures) linked to the JKM LNG price index mentioned above. To date, this remains very illiquid, according to Leach (2016).

Singapore launched a futures contract in early 2016, building on its domestic spot market and its efforts to become a hub for LNG trade. However, Singapore's domestic market is extremely small relative to the regional LNG trade, and it remains to be seen whether this will prove a successful new derivative market.

## 3.3. Further Development

How many natural gas futures contracts should we expect the market to produce? What will be the relationship among them? North America has a large array of natural gas spot price hubs and citygate spot prices, but futures trading is dominated by the Henry Hub contract. In the United Kingdom and in northwest Europe, the NBP contract dominates derivative trade. Is this structure stable? Should we expect additional European contracts to establish parity with the NBP? Are the Henry Hub and NBP contacts in competition with one another, or do they serve different markets? What about an East Asian natural gas futures contract?

For the European region, future developments probably depend upon how well integrated the different parts of the continent are and on whether Europe succeeds in creating a single continent-wide market. For example, because the NBP and Zeebrugge spot prices are tightly linked, derivative trade may remain concentrated in the NBP as it currently is, accompanied by a small parallel trade in the Zeebrugge contract. Schultz & Swieringa (2013) present evidence that the NBP futures contract provides important price discovery for any lasting innovations at either Zeebrugge or TTF, although there is some spot volatility in each of those locations that is distinct from the NBP market. Fracturing liquidity across multiple contracts is costly, so there is a natural pressure to reduce the number of contracts to the minimum required. This pressure is not always determinant—as we have seen in the case of oil, there have long been two contracts competing to be the global benchmark—but it is significant. Therefore, unless the spot prices at other locations reflect other, distinct drivers of supply and demand that cannot be reflected in the NBP price, it is likely that the NBP futures contract will serve as the main benchmark for the continent as well. Indeed, the European Union's regulatory objective is to create an integrated market, and insofar as that means that major supply and demand shocks impact prices similarly across the continent, it would seem natural that one futures location could be sufficient for this purpose. However, if the European marketplace develops so that there are important differences in price formation between large segments of the continent, derivative trading might become more fractured. It is unclear what impact Brexit may have on the integration between the natural gas markets in the United Kingdom and the northwest of continental Europe.

What about the global marketplace? Could we see the establishment of a single global benchmark? In order to answer this, it makes sense to start by considering the degree to which there is a global natural gas market—one great pool—or several distinct regional markets, and how this may evolve going forward. Historically, natural gas markets have always been regional. The expanse of the pipeline network defined the expanse of the market. Although shipments of LNG offer the theoretical potential for linking regional markets, the scale of trade in LNG has only recently begun to transform that potential to reality. By 2008, the LNG share of world gas trade was about 28%, but regasified LNG still made up only 7.5% of world gas consumption. Brown & Yucel (2009) find that the US Henry Hub and the UK NBP spot prices affected one another during the years 1997–2008. Neumann (2009) presents mixed evidence and Li, Joyeux & Ripple (2014) argue otherwise. Kao & Wan (2009) extend the analysis to include futures prices as well as spot prices in both countries, and find a single stochastic factor for the four price series; they also find that information arrives through the two futures markets in equal measure.

In the time period for these studies, both regions were importers of natural gas, and the case for integration hinged on the possibilities for Atlantic cargoes to switch their destination to whichever continent had the higher price. Since then, the massive development of cheap shale gas in North America has eliminated virtually any imports to that continent. Without any terminals for exporting LNG, the price in North America has fallen dramatically below the price in Europe and in Asia: For the year between April 2012 and March 2013, Stern (2014, p. 47) documents approximate prices as $2–4/MMBtu (Henry Hub), $10–11/MBtu (UK NBP, "with oil-linked long term contract prices $2–3 above that level"), and $15–17/MMBtu (Japanese LNG imports). The United States is now developing export terminals—Cheniere's Sabine Pass began shipments in February 2016—but it takes time to develop the infrastructure. Consequently, the segmentation of the regional markets is clear. Even as the overall scale of LNG trade expands, Ritz (2014) argues that the concentration of suppliers and their attempt to exercise market power naturally lead to segmentation in pricing, so that the market segmentation may be lasting.

The conclusion therefore seems to be that natural gas markets are currently still segmented into regions. Consequently, there remains a need for distinct benchmark futures contracts, with the Henry Hub contract serving that role for North America and the NBP contract serving that role for the United Kingdom and Europe. Should spot trade in East Asian LNG become liquid enough, it is very likely that a futures contract on East Asian deliveries would develop that would define a third regional natural gas market.

## 4. CONCLUSION

The two premier crude oil futures contracts traded today—NYMEX's WTI and ICE's Brent—were established in 1983 and 1988. They compete head to head for the role as the sole global benchmark contract. They are complemented by a set of futures contracts in refined products, most of which were established in the same general time period, as well as by minor contracts for other crudes at other locations. The two premier natural gas futures contracts traded today—NYMEX's Henry Hub and ICE's NBP—were established in 1990 and 1997. They exist side by side as regional benchmarks for the US and northwest Europe, respectively. They are complemented by a set of minor contracts for delivery at other locations.

Underlying the establishment of derivative markets in each of these two industries was a preceding change in organizational structure. In the oil industry, this occurred in the 1970s, when producing nations took control of pricing power and disrupted the vertical integration established earlier by the Seven Sisters. This gave impetus to the establishment of localized spot markets that were linked together into a single global oil market. In the natural gas industry, this occurred in the 1980s and 1990s in the United States, in the 1990s in the United Kingdom, and is an ongoing process in continental Europe. In each case, natural gas supply had previously been bundled together with transportation services under a vertically integrated structure. In each case, supply was or is being unbundled from transport, so that regional spot markets have arisen or are now developing.

On the foundation of this active spot trade, the futures market quickly established itself in each industry as the preferred location for price discovery. It plays an essential role in shaping intertemporal production, storage, and transport decisions.

Although the global market in crude oil involves many different grades and locations, the derivative market is dominated by two major futures contracts, accompanied by a very few other, less liquid contracts. This reflects the limited factor structure of the crude oil price. The global crude oil market is one great pool, and a single futures contract is sufficient to capture the major shifts in supply and demand driving the global price level. Concentrating trade in one contract improves liquidity and price discovery. Nevertheless, the WTI contract and the Brent contract have operated side by side as contestants for the role of the global benchmark. Minor contracts can incorporate localized innovations that shape the term structure at the short end.

The physical trade in natural gas has always had a stronger regional character because of the role of pipeline networks and the expense of shipping LNG between continents. Consequently, the Henry Hub futures contract operates as the benchmark for North American trade, whereas the NBP futures contract operates as the benchmark for the United Kingdom and northwestern Europe. In each region, contracts on other locations play a subsidiary role.

To date, there are no significant futures contracts specific to East Asia either for crude oil or for natural gas. This is because the organizational structure of the oil and gas trade in East Asia continues to be dominated by long-term vertically integrated structures. That may be changing, which could give rise to spot markets located in East Asia. Nevertheless, the prospects for East Asian derivative markets differ across the two industries. Because of the nature of the global oil market, a specifically East Asian crude oil futures contract may make only a marginal contribution to price discovery and may therefore have limited success. In contrast, a specifically East Asian natural gas futures contract may provide an important price discovery role for the region, and therefore could have a greater likelihood of success.

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## Errata

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