

April 2020

A Comparative History of Oil and Gas Markets and Prices: is 2020 just an extreme cyclical event or an acceleration of the energy transition?

Introduction

Natural gas markets have gone through an unprecedented transformation. Demand growth for this relatively clean, plentiful, versatile and now relatively cheap fuel has been increasing faster than for other fossil fuels.¹ Historically a 'poor relation' of oil, gas is now taking centre stage. New markets, pricing mechanisms and benchmarks are being developed, and it is only natural to be curious about the direction these developments are taking. The oil industry has had a particularly rich and well recorded history, making it potentially useful for comparison. However, oil and gas are very different fuels and compete in different markets. Their paths of evolution will very much depend on what happens in the markets for energy sources with which they compete. Their history is rich with dominant companies, government intervention and cycles of boom and bust.

A common denominator of virtually all energy industries is a tendency towards natural monopoly because they have characteristics that make such monopolies common.² Energy projects tend to require multibillion – often tens of billions of - investments with long gestation periods, with assets that can only be used for very specific purposes and usually, for very long-time periods. Natural monopolies are generally resolved either by new entrants breaking their integrated market structures or by government regulation. Historically, both have occurred in oil and gas markets.³ As we shall show, new entrants into the oil market in the 1960s led to increased supply at lower prices, and higher royalties, resulting in the collapse of control by the major oil companies. Initially, the creation of the Organisation of Petroleum Exporting Countries (OPEC) was an attempt to prevent IOCs from reducing the posted prices which would have caused a fall in the revenues accruing to the governments. Later, in the early 1970s, they assumed the control of the pricing system with mixed results.⁴

Monopoly structures in North American gas markets started to break up in the 1980s and in Europe from the 1990s to the 2010s but remain relatively intact in Asia. Japanese, Korean and other utilities traditionally purchase gas on long term, oil price-related contracts and pass on the price risk onto the consumers, justifying some of the price premium on the grounds of security of supply. However, starting

¹ IEA (2019) p. 175. 'Over the next two decades, global demand for natural gas grows more than four times faster than demand for oil in the Stated Policies Scenario. Natural gas sees broad-based growth across the energy economy, in contrast to oil where growth is concentrated in parts of the transport sector (trucks, shipping and aviation) and petrochemicals.'

² Economists define a 'natural monopoly' by presence of both economies of scale and 'sub-additivity'. The latter simply means that it is more efficient to have one provider than two or more. Natural monopoly can emerge in perfectly competitive markets. Economists define 'natural monopoly' by presence of both economies of scale and 'sub-additivity'. The latter simply means that it is more efficient (cheaper) to have one provider than two or more. For more details, see The New Palgrave Dictionary of Economics (1998), p. 306.

³ Mitchell (1976), p. 108.

⁴For an overview, see Parra (2004), p. 276 and more recently Fattouh and Imsirovic (2020), p. 7.

in 2019 and accelerating in 2020, short-term and spot markets offer LNG from various and secure sources at low, gas-related prices exposing traditional practice as illogical and inefficient.

This paper will take a very broad economic and historical perspective to compare the two industries, specifically in relation to pricing. This paper starts with a short history of the oil industry and shows how the changing structure and liberalisation had an impact on development of spot prices, benchmarks and a whole network of associated derivatives markets. This is followed by a history of gas pricing with emphasis on recent development and importance of Asian LNG pricing. We then draw parallels between the evolution of pricing in oil and gas markets and consider whether 2019/20 developments simply represent an extreme phase of the regular commodity cycle or could mark a dramatic acceleration in the transition away from fossil fuels. Finally we summarise and conclude.

Oil Markets, Monopolies and Prices

End of the 'Golden Era' of oil 'Majors'

In the 1950s and 60s, the industry and the markets were largely run by large oil companies or 'Majors'.⁵ They did all the exploring, producing, transporting and refining of oil. Also, they distributed and marketed the finished products. In other words, they were vertically integrated. This structure gave the oil companies control of every barrel from the time it was taken from the ground to the point of its use. The production was fine-tuned to the prevailing demand for petroleum products ensuring an overall price stability from the 1930s to the early 1970s.⁶

The industry was also integrated 'horizontally'; oil was carefully supplied from various geographic areas around the globe to ensure that supply and demand were balanced at lowest cost. Horizontal integration was done through joint ownership in several operating companies throughout the Middle East (ARAMCO, Anglo Persian - later to become British Petroleum, Kuwait Oil Company etc). The companies operated several mutual agreements, preventing 'harmful' competition⁷. The share of each 'Major' oil company in any of the markets was to remain 'As-Is' (in line with the prevailing market shares in 1928). By 1950, the 'Seven Sisters' owned 70% of the world refining capacity outside the Communist block and North America, almost 100% of the pipeline networks and over 60% of the world's privately-owned tanker fleet. They priced crude oil using 'posted prices' to maximise they own revenues within their vertically integrated systems. The producing countries received royalties on a percentage basis and posted prices were kept low to minimise them.

Towards the end of the 1950s, cracks started appearing in these cosy arrangements. Existing oil producers such as Venezuela and Iran were pushing for higher oil revenues and hence production. Large profits of the oil 'Majors' were attracting 'newcomers' in terms of smaller 'independent'⁸ oil companies. In Libya, the 1955 Petroleum Law offered many smaller concessions and stricter terms for exploration than the existing producers.⁹ More than half of the Libyan production ended up in the hands of companies which had no integrated systems in Europe (such as Conoco, Marathon and Amerada Hess) and hence no outlets for the oil. In 1956, BP and Shell found oil in Nigeria. In 1959, ENI started

⁵ Sampson (1988) p 475. Also referred to as the 'Seven Sisters': Exxon, Shell, BP, Chevron and Texaco (now Chevron), Gulf and Mobil (now both Exxon).

⁶ BP (2019), p.24.

⁷ Mechanisms for controlling these large petroleum reserves were ingenious, generally based on various 'rules' such as Average Program Quantity (APQ) in Iran, the 'Five Sevenths' rule in Iraq and the 'Dividend Squeeze' in Saudi Arabia. Monopoly prices were charged using a 'Gulf Plus System'; all delivered oil prices included freight cost from the US Gulf regardless of its origin.

⁸ The term loosely means companies 'other than Majors'. In USA, these were: Amoco, Sohio, Conoco, Atlantic Richfield (Arco), Occidental and some others. By and large, they emerged from Texas, which, in 1960 produced some 39% of US oil. Libya was a stepping stone for Amerada (Hess), Continental and Marathon. Occidental took off in Russia and Getty in Saudi Arabia and later Iran. In Europe, 'independents' included French Total (CFP) and Elf, Italian Agip (ENI), Belgian Petrofina and others. These newcomers, such as J.P. Getty paid more for concessions and offered higher royalties. For an excellent narrative, see Sampson (1975), Chapter 7.

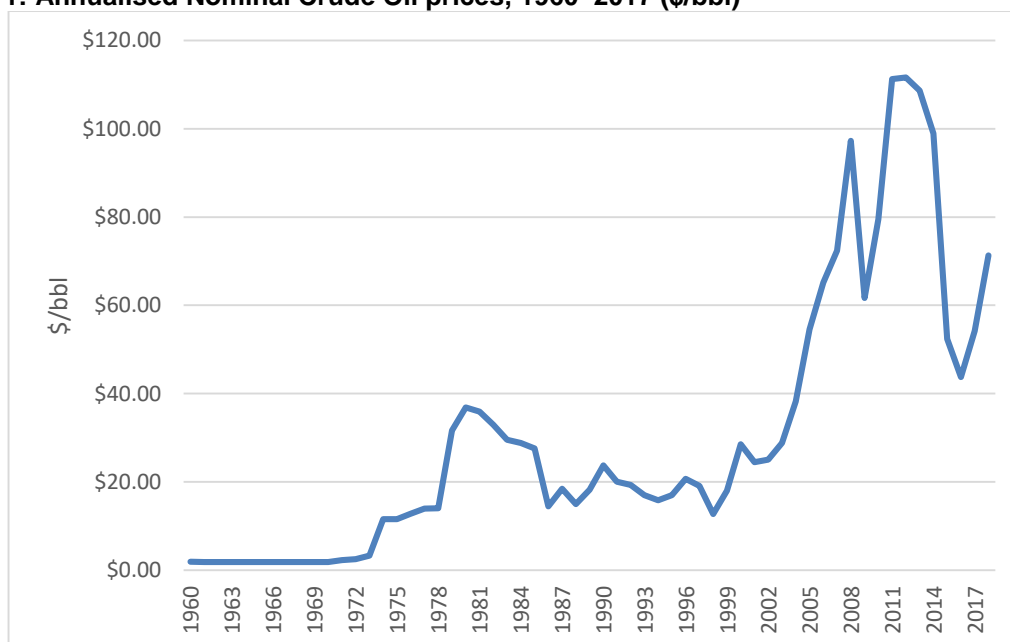
⁹ Yergin (1991), p. 528.

importing cheap Russian oil from the Urals region into Italy, undercutting posted prices. At the same time, the US had an import quota system, designed to protect its domestic oil producers. This legislation left the independents 'stranded' with oil which had to find markets elsewhere in the world.

These newcomers, not unlike the independent shale producers today, were keen to get the oil out of the ground quickly and secure a return on their investment. Oversupply was becoming obvious and oil was being offered at a discount to posted prices. In the 1960 to 1965 period, the Majors' share of European refining capacity fell from 67% to 54%. This intensified competition in the products markets reducing the refinery margin and putting further pressure on the oil prices. The Majors were losing the ability to balance supply and demand and pressure on the integrated structure of the industry increased.

At the same time, producing countries wanted to increase the posted price and reassert control over their natural resources, resulting in equity participation in the existing concessions and outright nationalisations in some countries.¹⁰ The 'last straw' was a move by Exxon, the largest Major and a price leader to cut posted price of up to 14 cents per barrel - without warning or consulting the governments of the producing countries - other international companies in the Middle East followed suit. Producing countries acted decisively and arranged a meeting on September 10th, 1960 in Baghdad. Four days later, the Organisation of Petroleum Exporting Countries (OPEC) was born.¹¹ Equity participation and nationalisation profoundly affected the structure of the oil industry. The majors 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. While the majors retained both their upstream and downstream assets, their position became more imbalanced: 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 control of the Majors.

Figure 1: Annualised Nominal Crude Oil prices, 1960–2017 (\$/bbl)



Source: BP (2019), p.24.

¹⁰ They also had strong leaders such as Nasser in Egypt, Muammar al-Qaddafi in Libya, Boumediene in Algeria, Abdullah Tariki in Saudi Arabia and Perez Alfonso in Venezuela. Apart from being better educated than their predecessors, they shared strong anti-colonial feelings.

¹¹ Founding members were Saudi Arabia, Venezuela, Kuwait, Iraq and Iran.

Thus, the early 1970s ended the era of control of the crude oil industry by the Major oil companies. Control of production decisions shifted from these companies to national governments and their national companies giving them a power to decide output and set oil prices. The new system was centred on the concept of reference or marker price with Saudi Arabia's Arabian Light being the chosen marker crude.

Despite these fundamental changes, in the early stages of the OPEC administered pricing system, OPEC countries remained dependent on the majors to lift and dispose of the crude oil and initially sold only small volumes through their national oil companies to firms other than the old concessionaires. As a result 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. A distinction between buyers and sellers became clear. As the horizontal market control by the Majors broke up, oil prices became highly volatile (Figure 1).¹²

'Spot' markets and prices

Following the collapse of horizontal integration in the early 1970s, the vertical integration of the industry ended with the fall of Shah of Iran in 1979. After the revolution, the Majors were forced to cancel third-party oil deliveries, which drove buyers of oil into the spot market.¹³ With no vertically integrated market tightly controlled by the companies, discrepancies between nomination dates, quantities, types and location of the crudes purchased by refiners appeared. To remedy these problems, term contract holders had to increase crude swaps and trade among themselves¹⁴. The result was a massive growth of spot trade volumes from some 3-5% in January 1979 to about 15-20% by March of the same year.

OPEC pricing arrangements were challenged by price volatility. Official Saudi prices were not changed frequently enough to reflect the volatility in the spot market. For example, at the 1979 Geneva OPEC meeting, the Arab Light price was increased from \$18 to \$24 per barrel as the spot price rocketed to \$45 per barrel. It was obvious that this price risk had to be managed. This was especially the case as the term supplies from OPEC countries were generally of a long-haul nature.¹⁵ In a volatile market, the price could significantly change between the time of purchase and delivery, exposing both seller and buyer to a large financial risk. Around the same time, large oil discoveries were made in the North Sea, facilitating relatively free market trading of the commodity that could be used to manage price risk.

The Ekofisk oilfield was discovered in 1969 in Norway by Amoco, Forties in 1970 by BP and Brent in 1971 by Shell.¹⁶ By 1980, North Sea production was 2 million barrels per day (mbd), making the region an important supplier of non-OPEC crude oil. Underpinned by English law, with standardised contracts¹⁷, no destination restrictions and tax advantages in 'spinning' or 'churning' the cargoes, the North Sea Brent market developed into the premiere, transparent and liquid spot market.¹⁸ Price reporting agencies (PRAs) Argus and Platts added to the transparency of the market.¹⁹ Benchmarks were set by participants in the spot and paper markets ('price makers') and the producers became 'price takers'. When we talk about the price of oil today, we normally mean the price of one of these

¹² McNally (2017), pp.130-141: '...OPEC ... announced a unilateral price increase of the benchmark Arabian Light from \$3.01 to \$5.11 per barrel, a 70 percent bump...'; 'Saudi Arabia fuelled the panic by cutting production by around 600 kbd in January 1979. Spot oil prices rose from \$12.80 per barrel before ... October 1978 to \$21.80 in February 1979...'

¹³ Although this process accelerated following the Iranian revolution, had its roots in the early 1970s. In the ten years following the Arab embargo in 1973, the oil available to the Majors fell by nearly 50%. Equity volumes fell even more, by about 75% and their share of internationally traded oil fell from 62% to 37%.

¹⁴ Swapping cargoes to minimise cost and optimise delivery will become common in the 2010s in the LNG markets.

¹⁵ A very large crude carrier (VLCC) would take about six weeks to arrive to NWE from the Arab Gulf.

¹⁶ McGrandle (1975).

¹⁷ Such as the Brent 'SUKO 1990' (Shell UK) 1990 contract.

¹⁸ For a comprehensive introduction, see Mabro and Horsnell (1993).and also Fattouh (2010) .

¹⁹ Platts started publishing its 'Crude Oil Market Wire' in 1978, and in the same year Argus started first daily reporting on the emerging spot crude market in the 'Argus Telex'. Platts started publishing Brent price assessments in the early 1980s

benchmarks. Derivative markets which grew alongside Brent and WTI facilitated risk management associated with physical trading. These benchmarks became the backbone of oil trading.

Throughout its history, OPEC has experienced disarray in its ranks over pricing policy and fundamental long-term strategy. This was particularly obvious at the 1980 conference in Algiers where a lack of agreement led to a 'free for all' policy. By adhering to the system of 'Official Prices' which most of OPEC was abandoning, Saudi Arabia was forced to reduce its volumes and take on the role of a 'swing producer'.²⁰ But their rigid official prices were falling out of line with the 'real' spot market, and Saudi Arabia rejected a continuous decline in the volume of their exports (exports fell from about 10 mbd to just 3 mbd between 1980 and 1986!). They opted to recover their share of the world market by changing their sales to 'netback' prices.²¹ A year later, oil prices fell to \$8/barrel.²² Without an integrated structure, the industry resembled the early decades of intense competition, the booms and busts of the late 19th and early 20th centuries.²³

A gradual price recovery followed a key OPEC meeting in November 1986 which changed the overall strategy of the Organisation away from the 'official' prices and towards managing OPEC supply through a quota system. A new system of 'spot'-related formulae prices was gradually adopted, and free markets prevailed.²⁴ By 1987, over 60% of all traded oil prices were tied to the spot market. This principle of setting prices of individual grades of oil against a published benchmark has not changed to this day. Subsequently, three main benchmarks emerged in the key oil markets: WTI in the US, Brent in the Atlantic basin and Dubai in Asia.²⁵ Being seaborne crude, Brent has been the main international benchmark.²⁶ Over time, all three have had ups and downs, caused mainly by changes in production of the respective streams and changing oil flows.

The two key events leading to the birth of WTI contract happened in the 1980s: lifting of US price controls by the Reagan administration in 1981, and the creation of the WTI futures contract on the New York Mercantile Exchange (NYMEX) in March 1983. Following the 'decontrol' of prices in 1981, spot markets quickly grew and the price reporting agency (PRA) Platt's started surveying and publishing prices for WTI as well as the sour grades, Louisiana Light Sweet (LLS) and West Texas Sour (WTS).²⁷ The NYMEX WTI contract had a good and well-established location at Cushing underpinning the physical trades.²⁸

Being land-locked, oil balances at the Cushing storage hub are subject to changes in flows and infrastructure in and around the hub. For this reason, the oil price crash in 1986 led to a fall in domestic

²⁰ Saudi Arabia was forced to take on a role of a 'swing' producer, absorbing the impact of changes in supply and demand. Ever since the last Iraqi war at the end of 2011, the Saudis have used their large excess capacity to balance the market and regain leadership status within the Organisation.

²¹ The price is set to be equal to the value of the products derived from the given crude. In effect, it guaranteed a refinery margin which, in periods of excess refining capacity which prevailed at the time, resulted in falling products prices. This in turn, led to a collapse of oil prices.

²² A similar event happened later, at the end of 2014, in response to the growing US shale output. In both cases, it was previously high oil prices (1970s and early 2000s respectively) that encouraged new investment in exploration and production, eventually (with a time lag) resulting in oversupply. In the 1979 to 1985 period, oil's share of primary energy demand fell from 48% to 40%. World Bank (1995), p. 1.

²³ Montague (1903, Tarbell (2003).

²⁴ The national Oil Company Pemex of Mexico pioneered it. It involves setting 'official' discounts relative to other 'marker' grade such as Brent. These discounts are usually set once per month and would reflect relative quality differential between the two grades of oil. However, the 'absolute' price level is set on daily basis by the marker crude.

²⁵ WTI is a light crude oil, with an API gravity around 39.5 and 0.24% sulphur; Brent has an API of about 38 and is 0.37% sulphur, and Dubai is 'sour' or high sulphur (about 2%) with API gravity of about 31. Qualities of these grades have varied over time. Most importantly, over time, they simply became 'brand names' for baskets of crudes deliverable against these contracts. For details see Imsirovic (2019) and Fattouh and Imsirovic (2019).

²⁶ It is generally accepted that Dubai benchmark is derived from Brent. See Imsirovic (2014).

²⁷ For a historical overview see: Purvin & Gertz (2010).

²⁸ Ibid. 'The Cushing location not only represented a gathering hub for the local crudes for refiners in Oklahoma, Kansas and Missouri, but it also was the central gathering point for terminus of pipelines originating in Texas and Oklahoma with onward distribution to the main refining centres in the central and eastern Midwest markets in Indiana, Illinois and Ohio.'

production by over 1.5 mbd and change in flows around the hub.²⁹ Starved of the local crude oil, inland refineries had to import oil from the US Gulf (USG) using reversed pipeline flows.³⁰ Given the ‘price war’ at the time (not unlike the markets in 2020), foreign imports became competitive again and NYMEX (now CME) soon introduced an ‘alternative delivery procedure’ which allowed for the foreign sweet crudes to be delivered into the contract.³¹ This increased the ‘depth’ of the market; there was more oil to be delivered into the contract and more new players to do so. Open interest took off in 1986 and grew steadily from about 100,000 contracts then, to about half a million contracts in 1990s.

The greatest challenges for the WTI benchmark followed the increases in the Canadian production, particularly the huge growth in shale output, eventually leading to the lifting of the oil export ban in 2015. This trend started somewhat earlier, in the mid-1990s with increasing Canadian oil sands production³², which was mainly exported to the US where the Midwest and Midcontinent refineries invested in upgrading their facilities to take advantage of these cheap barrels.³³

After 2011, US shale oil production picked up substantially, choking off international imports and resulting in domestic oversupply. As there was a ban on US oil exports at the time, excess supply resulted in the price of WTI falling relative to other benchmarks. Oversupplied and banned from exports, WTI started trading at deep discounts to Brent as well as domestic LLS and became useless for trades in waterborne international markets. USG refineries and exporters of sweet crude from Europe and West Africa started to rely on LLS as an indicator of market fundamentals at the USG refining hub. Unhappy with the state of affairs, in 2009 Saudi Aramco switched from Platts WTI benchmark to The Argus Sour Crude Index (“ASCI”)³⁴ followed by Kuwait and Iraq later. The future of the benchmark was seriously in question. Fortunately, common sense prevailed, and the US oil export ban was lifted in December 2015, relieving the pressure at Cushing and lifting prices. WTI reconnected with the international oil markets, increasing and eventually achieving record volumes of open interest.³⁵

The explosive development of the Brent market started in a parallel and similar fashion: The Thatcher government’s opening of the energy markets to competition in the UK in 1981 and 1982 was instrumental in growth of free markets. Exploration and production business of the national ‘champion’ British Oil national Corporation (BNO) was denationalised, later to become a part of BP. Brent trading started as a ‘forward’ physical or ‘cash’ market where oil was ‘churned’ for tax optimisation reasons; dated Brent was simply spot traded Brent with loading dates.³⁶ Being a price of actual physical oil, Dated Brent is generally used as a benchmark for trades of other types of crude oil. PRAs such as Platts and Argus report a wide variety of price differentials (for instance, Urals, West African, Mediterranean, North Sea and even many Asia-Pacific crudes) vis-à-vis the Forward Dated Brent. This allows refineries to compare relative values of different qualities of oil and calculate which are the most optimal for their systems.

Due to falling production, other sweet North Sea grades were gradually introduced into the Brent delivery mechanism forming what we now call a Brent or ‘BFOET basket’ comprising and named after:

²⁹ Ibid, p. 14. WTI dropped to near \$10/Bbl at the lows in 1986. ‘... 25,000 producing wells were lost in 1986 and by 1990 that drop had approached 45,000 wells versus the peak number in 1985.’

³⁰ Seaway pipeline was converted (again) from gas to oil and started importing USG oil in 1996.

³¹ In 2020 Platts and Argus are considering inclusion of WTI into the ‘Brent’ contract. How times have changed!

³² Conventional production in Canada peaked at over 1.5 mbd in 1970; however, ‘oil sands’ production took off sharply in 2000s supported by high oil prices, raising total production to well over 3.5 mbd in 2018, most of it exported to the US.

³³ Due to geography and environmental reasons, Canadian production is ‘landlocked’ and confined to a monopsony buyer.

³⁴ The ASCI differential index is a daily volume-weighted average of deals done for the component crude trades of US sour grades of oil: Mars, Poseidon and Southern Green Canyon; it is expressed as a differential to WTI.

³⁵ This was not a smooth process. With shale output increasing by over 1 mbd on annual basis, offtake pipeline capacity lagged behind until at least 2020.

³⁶ It means that the nomination procedure has been completed and a three-day laycan or loading window is known. The seminal work on Brent, explaining details of the original forward market is Mabro and Horsnell (1993).

Brent, Forties, Oseberg, Ekofisk and Troll crude oils.³⁷ Physical volumes of oil in the 'Brent basket' have increased over time by widening the 'window' of cargo loadings which qualify for the price assessment of Dated Brent. Brent has been trading as a futures contract since 1983 and is listed on both ICE and CME exchanges.

By the late 1980s, global oil price formation mechanisms were firmly established. In subsequent decades, the market faced some difficult challenges, especially in terms of price levels and volatility. The key benchmarks overcame these challenges by evolving and adapting rather than radically changing. Their liquidity, coupled with a web of various derivative instruments based on them, enabled a smooth and relatively riskless flow of barrels across the globe. By contrast, natural gas price formation would change significantly over the following four decades. This is the topic of the following section of the paper.

Gas Pricing: the long (and painful) march towards Economics 101

Historically, natural gas started out as a 'poor relation' of oil. It was a by-product of oil production with 'little or no value'³⁸, usually flared or re-injected into the field to maintain the oil well pressure. As many fields were far from centres of consumption, it was often left in the ground as a stranded asset. This was due to its characteristics. Being a gas, it has low calorific value per volume (diesel contains about 850 times more energy)³⁹ and it is difficult to store and transport⁴⁰. While oil has found a niche in the transport sector where it is hard to replace (given its high energy density and ease of storage and transport), gas competes with most other fuels in power, industry, residential and commercial sectors.

The history of natural gas price formation can be simply summed up: the gas community never believed that prices should be set by the forces of supply and demand for gas i.e. Economics 101.⁴¹ Theoretical literature provides little guidance because the major energy and resource price theorists were writing before natural gas became a significant energy source.⁴² A theory worth considering is that gas pricing has been a product of discriminating monopoly behaviour – arising from natural monopoly - in the many markets where, by virtue of their monopoly positions, sellers or buyers were able to segment domestic and international markets and charge customers different prices for the same product.⁴³

Major obstacles to changes in price formation have been lack of transparency (commercial confidentiality is often a condition of international contracts and domestic prices are not available in the official statistics of many countries), and a plethora of units (btu, cubic metres, megawatt hours, therms, tons of LNG) and currencies. This is a stark contrast with the common, relatively straightforward and transparent dollars per barrel of the oil sector. A rough but acceptable generalisation is that over the past 40 years, in Europe and North America - markets which have accounted for the majority of international gas trade and have transitioned from monopolistic to competitive markets - prices have moved from:

³⁷ The physical oil underpinning the benchmark has been maintained by adding alternative delivered grades: Forties (introduced in 2002, with Buzzard field entering production in 2007), Oseberg (2002), Ekofisk (2007), and most recently Troll (2018). What is left of Brent blend crude oil, loading at Sullom Voe terminal, is now just a brand name.

³⁸ BP 1977, p.372.

³⁹ Calorific values of gas and diesel are about 55 and 45 MJ/ kg and densities are about 0.8 and 840 kg/ M3 respectively; which means calorific value of diesel is almost 850 times that natural gas per volume (cubic meter here).

⁴⁰ On a flip side, reservoir recovery of natural gas fields is about double (70–80 percent) that of oil (30–40 percent). Unlike oil, gas requires relatively little processing before it is sold.

⁴¹ This section deals mainly with international gas pricing or the price of gas delivered to importing countries either by pipeline or as LNG. The pricing of gas to end-consumers in national gas markets is a much more complex subject and may or may not relate to international prices depending on customer class. Very few gas and LNG exporting countries deliver gas to their domestic markets at prices related to their exports.

⁴² A possible exception would be Coase's transaction cost theory which considers long term contracts a determining factor in the development of markets

⁴³ Allsopp and Stern (2012).

- fixed, regulated or cost-related mechanisms through..
- prices linked to crude oil or oil products and finally to..
- market, spot or hub-based prices.

However, Asian markets, which import 70–75% of global LNG, remained largely monopolistic and dominated by oil-linked pricing.

The Evolution of Market Pricing in Different Countries and Regions

If a definitive date can be placed on the start of national and international market pricing for gas it is April 1990 with the start of the NYMEX futures market based on Henry Hub spot prices (although the latter had been quoted since the mid-1980s).⁴⁴ The US and Canada had emerged from a decades-long period of regulated prices and, following a brief period of (now long forgotten) oil-related pricing (which included Mexico), began a period which 30 years later continues to evolve in terms of depth and complexity.⁴⁵ Deregulation unleashed conventional gas supplies which had been constrained by the state and federal rules, creating a significant surplus of supply over demand and liquidity for Henry Hub (and other emerging hubs).⁴⁶

The next example nearly a decade later was in Great Britain⁴⁷ where, following a long period of cost-related pricing, the privatisation of British Gas ended its monopoly and opened the market to competition. This resulted in a flood of new gas supply, the creation of the National Balancing Point (NBP) in 1996 and the following year by the NBP futures contract on the Intercontinental Exchange (ICE).⁴⁸ NBP liquidity began to increase and climbed steadily through the 2000s. A feature of the British gas market was that, aside from a large Norwegian import contract, oil-linkage was never a significant price formation mechanism.

The Continental European price transition

More than a decade after Great Britain, and many false starts, continental north west European gas hubs began to achieve materiality due to a combination of surplus supply and the development of regulated third party access.⁴⁹ This finally broke the stranglehold of the monopoly gas suppliers which had operated the oil-linked pricing system, based on the Groningen principle of netback market pricing from oil products (mainly fuel oil and gas oil) since the emergence of a large scale gas market in the late 1960s and early 70s.⁵⁰ This principle had been logical at the start of the natural gas era as customers needed to be persuaded to switch from oil products to the new fuel, which required it to be priced relative to (but below) their existing energy source.⁵¹

Over time, both the NBP (Sterling) and the Dutch TTF (Euro) hubs increased their liquidity and, facilitated by the EU gas target model and introduction of entry/exit pricing which required all EU gas markets to trade gas at a virtual or physical trading point, market hubs (with varying degrees of liquidity) emerged all over Europe.⁵² In 2018 Gazprom established its own electronic sales platform and had

⁴⁴ Foss (2012) which also includes detail on Canada and Mexico. IEA (1998), pp. 93-118.

⁴⁵ For a brief history of North American international pricing including the oil-linked period see Stern (2012), pp. 46-54.

⁴⁶ Foss, loc.cit.

⁴⁷ The designation 'Great Britain' is deliberate as Northern Ireland's gas (and power) regime is governed by different laws. Northern Ireland did not have an 'NBP' equivalent until 2015 when the NIBP was created in order to comply with European Union Directives.

⁴⁸ Heather (2010), (2015) and (2019).

⁴⁹ Stern and Rogers (2014).

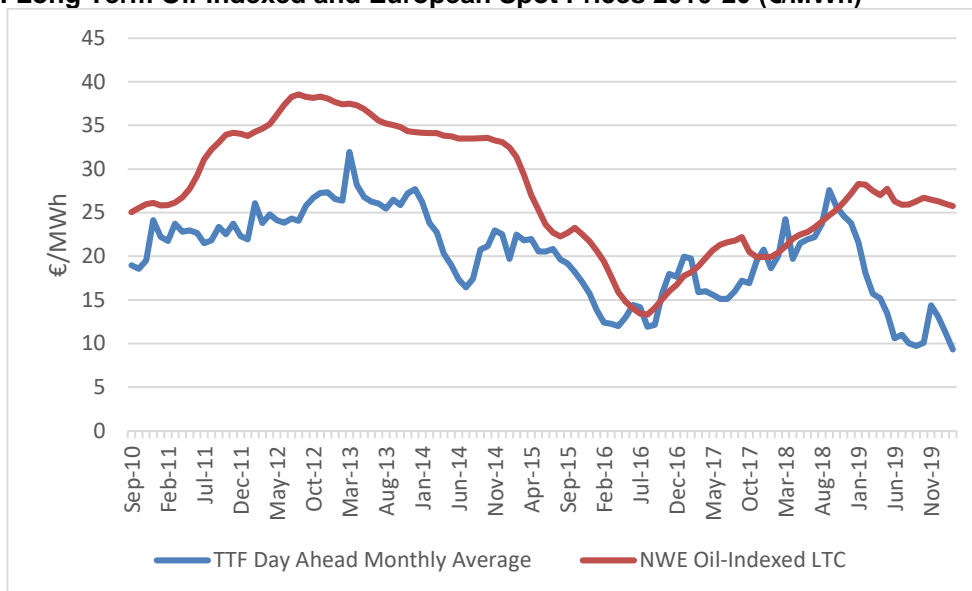
⁵⁰ More details can be found in Stern (2012).

⁵¹ The dissenting voice at that time was Professor Peter Odell who maintained that oil-linked pricing was never logical and had been created to high profits for upstream companies as well as the Dutch State. Odell (1969).

⁵² Heather (2015) and (2019); Yafimava, (2013).

been forced by European competition (anti-trust) authorities to offer hub prices to its (previously captive) customers in central and south east Europe.⁵³

Figure 2: Long Term Oil-Indexed and European Spot Prices 2010-20 (€/MWh)



Source: Platts, European Gas Daily.

With energy and gas demand falling, LNG supply being diverted from the US (where the shale gas revolution had removed the need for imports into the newly built regasification terminals) and oil prices rising around \$100/bbl, the commercial position of those with oil-linked contracts became untenable. Post-2008, their purchase prices were significantly higher than hub prices which were increasingly visible and available to end-users (as shown in Figure 2).⁵⁴ Commercial pressures mounted very rapidly and the transition of European long-term gas contracts from oil-linked to hub-based prices was exceptionally painful, involving substantial numbers of international arbitration proceedings a few of which were still ongoing in 2020.⁵⁵ By the time of the next great disconnect between oil-linked and hub-based prices at the end of the 2010s, the transition was virtually complete in most major European markets.

In 2005, nearly 80% of European gas was sold on an oil-linked basis but by 2018 that figure had fallen to around 25% with 75% of European gas sold at spot or hub prices (and regulated prices had virtually disappeared). But there remained considerable differences between regions as Figure 3 shows.⁵⁶ By 2018, north west Europe was virtually 100% market priced in comparison to less than 30% in 2005. In Central Europe, market pricing only emerged around 2010 but had increased to around 75% by 2018. Mediterranean gas markets still had more than 50% of their gas indexed to oil, and Italy accounted for much of the remaining 45% which was market-priced. South East Europe, which is mostly comprised of small markets still had 35% of gas linked to oil but the majority of the remainder was market-priced.

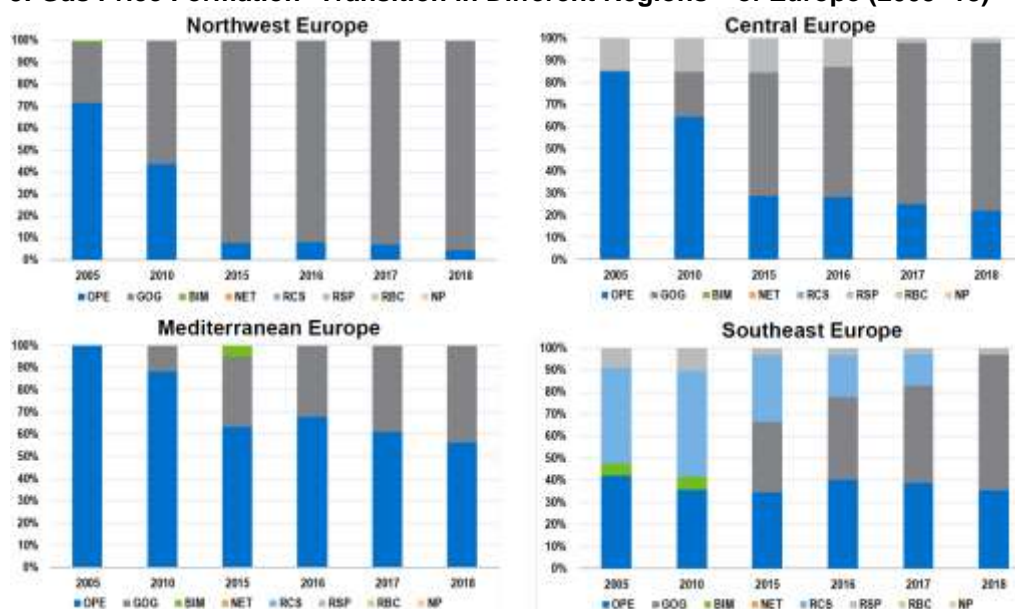
⁵³ Gazprom had previously been a very strong supporter of oil-linked prices. Stern and Rogers (2013); Sharples and Henderson (2019); Stern and Yafimava (2017).

⁵⁴ For the early years of this transition see Stern and Rogers (2012) and (2014).

⁵⁵ Similar problems had been experienced in North America and Great Britain but most of those were between parties in the same legal and regulatory jurisdiction, whereas continental Europeans were dealing with Gazprom, Sonatrach and other LNG exporting countries.

⁵⁶ Analysis of pricing at a regional level has been greatly assisted by the publication since 2006 of the International Gas Union (IGU) Wholesale Price Surveys.

Figure 3: Gas Price Formation* Transition in Different Regions of Europe (2005–18)⁵⁷**



*OPE – oil linked, GOG – Hub-based (or market prices), BIM – bilateral monopoly, NET- neback from final product, RCS- regulated cost of service, RSP – regulated social pricing, RBC- regulation below cost, NP – no price.

**NW Europe: Belgium, Denmark, France, Germany, Ireland, Netherlands, UK

Central Europe: Austria, Czech Rep, Hungary, Poland, Slovakia, Switzerland

Mediterranean Europe: Greece, Italy, Portugal, Spain, Turkey

SE Europe: Bosnia, Bulgaria, Croatia, FYROM, Romania, Serbia, Slovenia

Source: IGU various years.

In summary, by the end of the 2010s most of the major European markets had moved to market pricing. In the south east and Mediterranean regions of Europe oil-linked prices remained important, and in some smaller markets still dominant, but the trend towards market-pricing was clear and ongoing.

The Focus Switches to LNG

With a few regional exceptions, North American and European gas markets are overwhelmingly pipeline markets but in Europe, LNG is important as the marginal supply source. The changes described above led to the share of global pipeline imports linked to oil prices falling from 57% in 2005 to 30% in 2018; over the same period market-priced imports rose from 23% to 61%.⁵⁸ Global LNG import pricing changed rather less during 2005-18 with oil-linkage still dominant but falling from 82% to 66%, and the share of market-priced LNG rising from 13% to 34%.⁵⁹ In the second half of the 2010s, the focus of attention switched to LNG pricing, partly because of the huge increase in global LNG supply but also because of the volatility of oil prices which in turn impacted oil-linked LNG contracts. The final bastion of oil linkage is Asia and especially the major and emerging LNG markets where traditional long-term contracts are based on and indexed to crude oil prices.

⁵⁷ The region not included here is Scandinavia and the Baltics which includes: Estonia, Latvia, Lithuania, Norway, Sweden. This region accounts for a relatively small percentage of European gas demand and in 2018 was 40% oil-linked and 60% hub-priced. IGU (2019), p.59.

⁵⁸ Ibid, Figure 3.3, p.23.

⁵⁹ Ibid, Figure 3.5, p.24.

JCC Pricing

Crude oil price linkage was introduced into Japanese LNG import contracts in the 1970s when LNG was replacing crude oil in Japanese power stations. By the time that Japan was joined by other LNG importers in the Pacific Basin (South Korea in 1986 and Taiwan in 1990), the pricing principle of the “Japan Crude Cocktail” – usually abbreviated to JCC⁶⁰ – was well established. The price formula is based on the average price of crude oils imported into Japan, and the main focus of commercial negotiations is the index – known in Pacific LNG contracts as ‘the slope’ – or the extent to which the LNG price changes in response to a change in crude oil prices.⁶¹

Over subsequent decades, Japanese electric power utilities moved away from crude oil-fired generation with the exception of peaking and emergency situations (for city gas companies, crude oil was never a competing fuel). It was also somewhat strange that South Korean and Taiwanese (later followed by Chinese and Indian) LNG buyers should price their imports relative to crude oils imported into Japan. Despite these contradictions, the JCC pricing and contractual framework worked well for many decades (similar to oil product-linked pricing in Continental Europe) since in all Asian countries, gas was replacing oil products in stationary energy balances. Cost pass-through mechanisms protected importing utilities from risks associated with purchase prices, and although Japan and South Korea flirted with liberalising their gas and power markets in the 1990s and 2000s, this never progressed to exposing incumbents to (what in North American and European markets would be considered) serious competition.⁶²

Figure 4 shows US and European hub and Asian LNG prices for the period 2008-20. In 2008, the regional prices were in a narrow band, and for most of 2009 regional spot/hub prices⁶³ were also roughly equivalent but broke apart over the course of 2010. The period 2011-15 saw an unprecedented spread of regional prices: Henry Hub prices averaged \$3-5/MMBtu at the same time as Asian LNG prices were in double figures – reaching \$18/MMBtu at their height – with European prices close to and occasionally above 10/MMBtu. This period was a product of a coincidence of events, none of which could have been foreseen:⁶⁴

- rapid low cost shale oil and gas development in North America;
- Brent crude oil prices at or above \$100/bbl;
- the impact of recession and liberalisation forcing European markets to move from oil-linked to market pricing;
- the Fukushima disaster and subsequent closure of Japanese nuclear reactors, combined with problems in the Korean nuclear sector and rapid economic growth in China, creating far high demand for LNG in Asia than had been anticipated.

⁶⁰ The official name is “Japan customs-cleared crude oil price”.

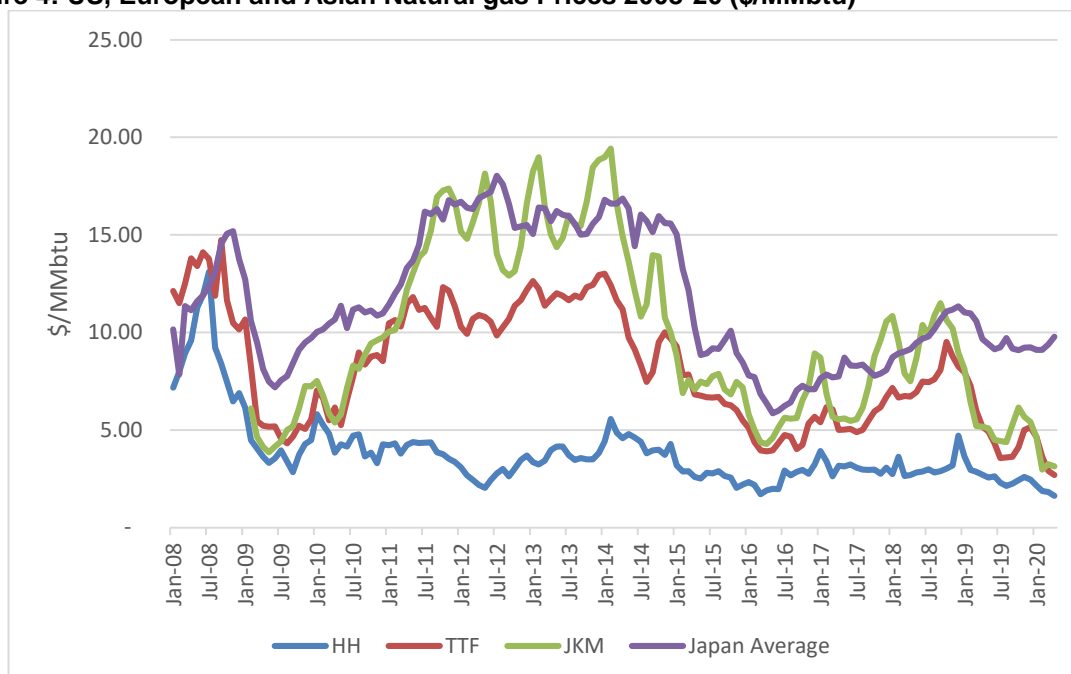
⁶¹ Flower and Liao (2012). For details of the history see Stern (2012), pp. 68-73.

⁶² In the late 2010s competition was introduced into the Japanese gas and power markets but, in the gas sector had still not reached significant proportions. Aside from Singapore (which has a liberalised gas market), other Asian LNG importers had made little progress towards liberalisation with the exception of China where structural changes were being introduced, and Malaysia where legislation and regulation were in place. Meidan (2019), O’Sullivan (2019), Kumar and Stern (2020).

⁶³ Asia’s JKM spot price only began regular quotations in early 2009.

⁶⁴ These were the main factors but there were also others. Stern (2016).

Figure 4: US, European and Asian Natural gas Prices 2008-20 (\$/MMbtu)*



* 'Japan Average' is roughly equivalent to crude oil-linked JCC prices; February-April 2020 are estimated taking into account the lag effect of crude oil prices in long term LNG contracts.

Sources: Platts and Argus data.

Figure 4 shows that by early 2020, regional spot prices had again converged significantly and in Europe and Asia had reduced to historical lows. This happened significantly before the collapse in oil prices which can be ascribed (at least in part) to the coronavirus pandemic. The fall in gas prices was caused (at least partially) by a 25% increase in global LNG capacity in the five years up to 2019 (and especially spot and short-term LNG deliveries) with an additional 10% expected in 2020.⁶⁵

But the 2011-15 period had convinced many LNG project promoters that \$10-15/MMbtu would be the long-term price range for LNG, driven principally by high Asian demand led by China and India. This was despite evidence that domestic wholesale price levels in many non-OECD countries had never been high enough to support imports in this price range without substantial government subsidy.⁶⁶ And furthermore that the surge in Chinese gas demand – a product of very high GDP growth and coal to gas switching policy – might not be sustainable. This period of historically high prices in Asia, and an unprecedented regional price spread, informed the decisions of many project developers, particularly in the US, to press ahead with new LNG projects. US projects were welcomed by Asian buyers because they introduced a new price formation mechanism based on Henry Hub rather than JCC prices.

Henry Hub-based pricing

The first US LNG projects, with Cheniere as the seller, created a Henry Hub-based price formula to sell LNG to buyers on an FOB basis. The formula was the Henry Hub futures price multiplied by 1.15 to cover the cost of gas consumed as fuel in the liquefaction process and transport costs to the liquefaction facility, plus a liquefaction fee. The liquefaction fee in Cheniere's first agreement was set at

⁶⁵ Global capacity rose from around 400 bcm in 2014 to more than 500 bcm in 2019 and will increase to 560 bcm in 2020. Fulwood (2020a), Corbeau (2016), Figure 10.1, p. 565.

⁶⁶ Stern (2019) Table 1. showed that in very few non-OECD countries currently importing (or expecting to import) LNG were wholesale gas prices consistently higher than \$8/mmbtu during the period 2000-18, and in many countries prices were significantly below that figure.

\$2.25/MMBtu; for subsequent customers this rose to \$2.50 and \$3.00/MMBtu.⁶⁷ During 2011-15, Henry Hub prices in the \$2-5/MMBtu range meant that those signing US LNG contracts during this period could anticipate delivering LNG to Asia for \$7-10/MMBtu, and in Europe at somewhat lower figures, thereby earning a healthy profit. As the regional price spread closed in 2015/16 with prices converging to a relatively narrow range in 2019/20, US LNG exports became increasingly commercially problematic with buyers struggling to cover even their short run marginal costs, let alone the full cost of deliveries.⁶⁸ The post-2016 period has therefore exposed the problem of commercial decision-making based on price *level* rather than price *formation*. Henry Hub prices reflect supply/demand conditions in the US market, and it was therefore always a risk to sign long-term LNG offtake contracts for sale to markets with different supply/demand dynamics.

Despite their current commercial difficulties, US LNG export projects made two valuable contributions to global LNG and natural gas trade:

- for the first time in many decades, Asian LNG buyers were able to purchase LNG on some basis other than crude oil;
- US LNG is sold fob i.e. the destination market is at the discretion of the buyer. The majority of the US volumes have been purchased by 'portfolio players' – mostly the international oil and gas companies, but also some large national buyers – who have purchased on a long term basis but are selling on a short term basis to the markets where they can achieve the best prices. The revolutionary aspect of portfolio player model is that there are no sales contracts with end-users and hence no contract prices. The players take the risk that the market price – however determined – will cover their LNG acquisition and delivery cost.⁶⁹

Short term LNG trade and JKM

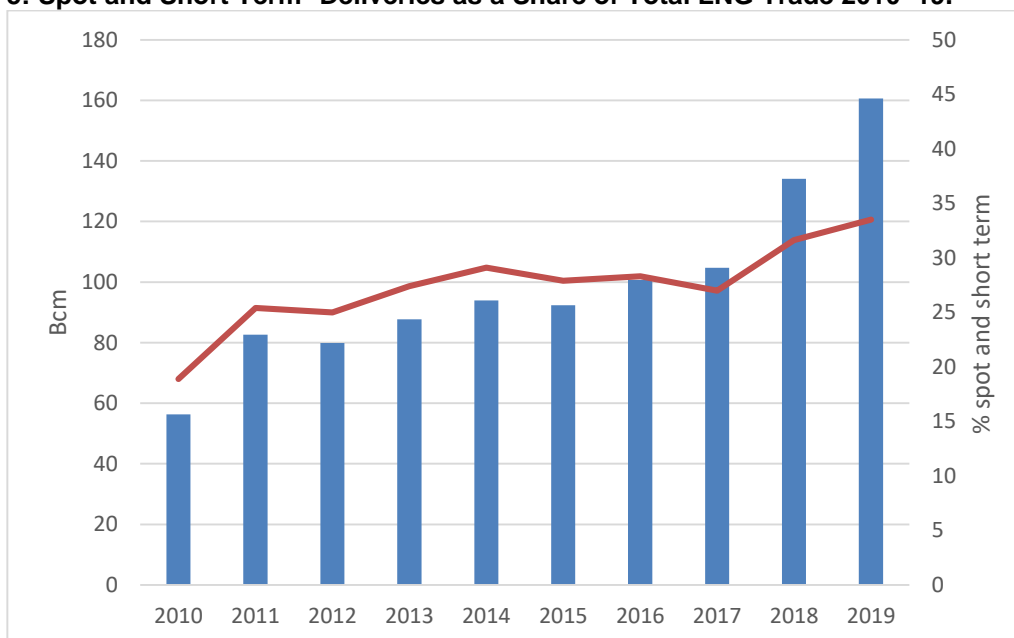
In addition to their contribution to global LNG supply, the US projects made a major impact on trading liquidity and the emergence of an Asian LNG price marker.

⁶⁷ Stern and Rogers (2014). These were modified tolling contracts where Cheniere sourced the gas and delivered it to the liquefaction plant with the buyer taking delivery at the outlet of the liquefaction plant. Other US projects included pure tolling contracts where the buyers perform the supply and delivery functions themselves, paying the operator of the liquefaction plant only a tolling fee.

⁶⁸ Fulwood (2020a). Buyers who have signed a long term contract for US LNG supplies are contractually obliged to pay the tolling fee ie the \$2.50-3.00/MMBtu quoted above and therefore this is similar to 'take-or-pay' and is therefore 'sunk cost'. If they also own (rather than having to charter) the LNG ships they may also regard the shipping cost as sunk. Their short run marginal cost is therefore the Henry Hub price plus the cost of getting the gas to the terminal (HH*1.15 in the example above) plus regasification cost if applicable.

⁶⁹ Rogers (2017).

Figure 5: Spot and Short Term* Deliveries as a Share of Total LNG Trade 2010–19.

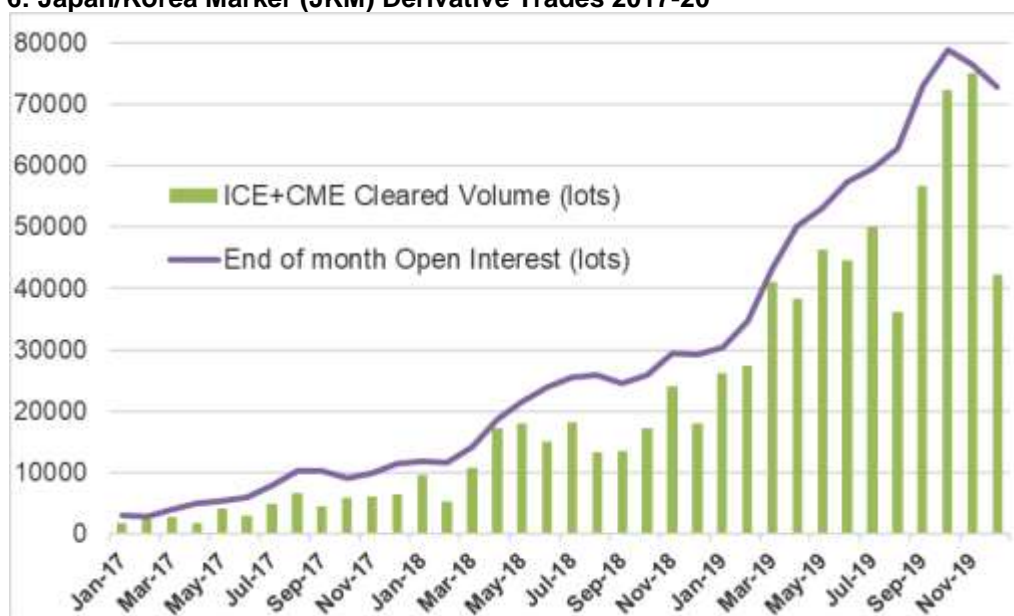


*Defined as deliveries under contracts with a duration of 4 years or less.

Source: GIIGNL (2020), p.35.

Figure 5 shows that spot LNG deliveries and short-term trading has expanded substantially in the 2010s reaching 34% of total LNG trade in 2019.⁷⁰ In that year, around 60% of these cargoes were delivered to Asia⁷¹, and can be assumed to be largely based on the Platts Japan-Korea Marker (JKM) price.

Figure 6: Japan/Korea Marker (JKM) Derivative Trades 2017-20



Source: Platts.

⁷⁰ Note that spot and short-term contracts are those of up to 4 years which is substantially longer than traditional definitions of spot trade. Shell (2020), p.25 shows that around 1600 spot cargoes were delivered in 2019.

⁷¹ Ibid.

Figure 6 shows that trades using JKM have expanded substantially since 2018 in terms of futures, options and swaps. In June 2018, physical trade in cargoes began using JKM 'Market on Close' methodology and by the end of 2019 these had expanded very rapidly.⁷² This rapid expansion of short-term trade in Asia seems likely to accelerate the development of market pricing facilitated – as it was in North America and Europe – by a prolonged supply surplus. With further significant additions to LNG supply assured by final investment decisions on projects in 2019⁷³, and uncertain gas demand prospects due to anticipated recession due (at least in part) to the Coronavirus pandemic (but potentially offset by low LNG prices), market pricing will continue to spread across Asian markets. Issues yet to be resolved are:

- whether JKM will be sufficient as a price marker for the entire Asian market or whether national or regional market hubs⁷⁴ will be required (as in North America and Europe);
- whether regional hubs can be created in the absence of any significant liberalisation of the major Asian gas markets and access to LNG terminals and pipelines still mostly at the discretion of dominant national and regional players;

The collapse in Asian LNG prices in 2019 ahead of the 2020 oil price collapse raised the possibility of a European-style tsunami of price reviews and arbitrations, with confirmation that at least some proceedings were underway.⁷⁵ This seemed to be overtaken in 2020 by Asian buyers (led by China and India closely followed by Japan and Korea) claiming force majeure on their LNG contracts based on a combination of inability to take cargoes (due to a collapse in demand) and logistical problems at ports due to coronavirus.⁷⁶

Is 2020 just an extreme cyclical event or an acceleration of the energy transition?

The collapse in oil and gas prices in 2020, due to the decline in economic activity stemming from coronavirus pandemic is leading to a debate on whether it is just an extreme version of the familiar commodity cycle or whether it may result in a turning point for oil and gas markets, accelerating the transition away from fossil fuels towards a low carbon era.

Just an extreme cyclical event?

Following the 'Great Recession' of 2008, OPEC struggled to balance the market by cutting production, only to see its market share diminish. Price levels in excess of \$100/bbl in the early 2010s attracted new entrants into the market, leading to massive investments in production and new technologies⁷⁷. In particular, US shale production exposed OPEC's vulnerability: member countries have a high 'social cost' of production as their economies are extremely dependent on oil revenues.⁷⁸ In November 2014, it declared a 'price war' on shale by increasing output. However, collapsing oil prices caused alarm among the OPEC members threatening their revenues and, in late 2016, forced OPEC to seek help from producers outside the Organisation, particularly from Russia the world's second biggest oil producer.⁷⁹ This created a new forum, often referred to as 'OPEC+'.⁸⁰

⁷² For details see Heather (2020).

⁷³ Final investment decisions on new LNG projects in 2019 totalled more than 90 Bcm of capacity. Fulwood (2020b).

⁷⁴ Discussion of Asian hub development can be found in: IEA (2013), Rogers and Stern (2014), Fulwood (2019), Kumar and Stern (2020).

⁷⁵ Ason (2019).

⁷⁶ Ason and Meidan (2020); Stapczynski (2020).

⁷⁷ Cheap money was another factor, spurring investment in the US shale, especially as fracking technology came of age.

⁷⁸ See Dale and Fattouh (2018)

⁷⁹ Yermakov and Henderson (2020) explain the likely short-term motives behind Russian decision to join forces with OPEC.

⁸⁰ A loose alliance of 11 non-OPEC countries including Russia. The 'Declaration of Cooperation' was signed in December 2016 and then subsequently extended.

By the end of the decade, the flow of US crude increased to such an extent it flooded both European and Asian markets. In March 2020, following an inability of OPEC+ to agree cuts in output, in the face of the biggest collapse in global demand in recent history caused by the COVID-19 pandemic, prices fell below \$30/bbl causing widespread alarm. On April 12, with unprecedented backing from the US and other G20 countries, 'OPEC+' agreed to cut almost 10 per cent of global supplies.⁸¹ This greatest cut ever in the history of OPEC+ was not enough to prevent a further 'disorderly' price collapse in the US as WTI price went negative eight days later.⁸² Other benchmarks may not be so dramatically affected because of greater storage availability.⁸³ Much of the volume of the 'cut' would have happened anyway, forced by the lack of demand due to the pandemic, and these events clearly exposed the inability of OPEC to balance the market unilaterally. The resulting price volatility has severely tested the benchmarks to, and in the case of WTI beyond, their limits and additional tests lie ahead until demand recovers.

The 'glut' of LNG supply – long anticipated by observers – finally arrived at the end of 2018, and demand in Asia was not strong enough support prices. Although there was speculation that LNG import prices below \$6/MMbtu could create significant new demand in low income countries, this has so far not materialised to the extent that might have been expected.⁸⁴ The collapse in regional spot gas prices can be dated from the start of 2019 and continued throughout that year and into the following year, well ahead of the 2020 oil price collapse. As we conclude this article, the main spot gas benchmarks are all in the range of \$1.50-2.00/MMbtu, which is unprecedented in terms of price level, and may go lower as European storage becomes full towards the middle of the year. Even before the Coronavirus pandemic, natural gas prices were projected to remain low for several years into the 2020s and the consequent recession will extend this period, possibly somewhat offset by delays in projects under construction due to logistical problems, and likely further delays for the long queue of projects waiting to take a final investment decision.

A several year period of prices below \$6/MMbtu, which is entirely likely, will accelerate the transition from oil-linked to market pricing in Asia. There will be arguments that the collapse of oil prices has taken the pressure off LNG buyers to make this change (because oil indexation means that long term LNG contract prices have moved much closer to spot prices). But the exposure of LNG buyers to the volatility of an oil market whose major decision-makers have fundamentally different interests to - and supply/demand fundamentals which lack any significant correlation with - those of gas, has become commercially untenable. Gas pricing will become increasingly 'global' with regional differentials determined mainly by transportation costs. But for as long as Asian markets are not liberalised and lack liquid national or regional trading hubs, these differentials will not adequately reflect market conditions.

In summary, 2020 is certainly an extreme cyclical event for both oil and gas, and one which could keep prices low for several years. But it has become clear that oil and gas market dynamics have become increasingly different over the past several decades⁸⁵; both oil and gas are in a situation of oversupply but for different reasons. The common denominator is the US shale revolution which has significantly impacted both markets. The start-up of new US (as well as Russian and Australian) LNG projects many of which had been delayed, coincided with a period of lower than anticipated demand in Asia, and the lack of any mechanism to 'balance' the market. Due to the OPEC+ agreement, the weakness in the oil market post-2016 was not as apparent and the impact on prices in 2020 was therefore much more dramatic. Similarly the fall in oil demand, because of the impact on all forms of transportation, is likely

⁸¹ This initiative, OPEC++ (as some referred to it) potentially included even more countries such as Canada, US and Norway. The 'cuts' of 9.7 mbd are to be implemented for two months of May and June 2020 and then reduced for the 2H 2020 to 8 mbd and again to 6 mbd for the 1H 2021. Numbers here are highly debateable depending on the starting point for the cuts, exemptions etc.

⁸² Financial Times (2020).

⁸³ Fattouh and Imsirovic (2020).

⁸⁴ Stern (2019).

⁸⁵ This does not mean there is no relationship between oil and gas prices. But gas supply and demand both globally, and in individual markets, will be much more important determinants of gas prices.

to be greater than for gas, although the latter will face challenges particularly in the power sector. Overall, this cycle is likely to result in a much more competitive environment for both fuels.

In this short term perspective, the critical elements will be the speed of economic recovery, its impact on oil and gas demand, and whether economic instability in oil and gas producing countries could lead to political instability, which in turn could restrict supply and create a more rapid price recovery. Having said that, the events of 2020 could certainly be a glimpse of things to come in relation to the longer-term energy transition.

Or the start of an accelerated transition away from oil and gas?

More fundamentally the Coronavirus pandemic, the collapse in oil and gas prices and what is predicted to be a huge fall in oil and (possibly also) gas demand have raised the possibility that these events will dramatically accelerate the energy transition. Some commentators see these events marking the beginning of the end for oil and gas, and that price levels of \$50-100/bbl and \$8-15/MMbtu will never be seen again. In this view, renewables and new energy technologies, available at progressively lower costs, will take over energy balances. Fossil fuels will be in permanent surplus at low prices and eventually enter a death spiral as investors desert the sector for higher returns elsewhere.

Others see a completely different picture in which a protracted surplus of oil and gas supply over demand, and a period of very low prices, will dramatically slow the energy transition. Financial stringency will mean that governments lack the means to support low-carbon energy sources and technologies, and recession-induced reductions in carbon emissions will make it much easier for governments to meet their immediate emission reduction targets without imposing additional regulations or carbon taxes.

Aside from the fact that these two views may be based more on the hopes, rather than the analysis, of their protagonists they are likely to be flawed in at least two respects. First, the futures of oil and gas are likely to be fundamentally different because, as we have repeatedly stressed in this paper, oil is overwhelmingly a transport⁸⁶ fuel while gas has a more diversified and competitive demand structure. Should the strength of oil – the fact that it has not been seriously challenged in its transport niche – become its weakness if electric vehicles make rapid technological progress with associated cost reductions, this could indeed usher in a new era for oil. For natural gas there is no such obvious immediate challenge unless ‘green hydrogen’ (from electrolysis of renewable energy) and heat pumps can be developed and introduced on a very large scale at much lower costs.⁸⁷ While these developments are completely foreseeable, the question is how long they might take, given the inertia in the transport, industrial and residential heating sectors.

Second, the future of fossil fuels will be different in different regions. While Europe, despite its financial problems, may press ahead with its Green Deal and an accelerated transition to net zero emissions, similar urgency and commitment is not visible in most other regions aside from parts of North America. Asian countries, where the majority of the increase in energy demand is predicted over the coming decades, may be persuaded to abandon coal in favour of renewables and much lower cost gas. But commitment to rapid and radical energy transition is not yet visible.

The evolution of energy systems is measured in decades and, while the direction of travel in energy balances away from fossil fuels is not in dispute, the issues remain the time scale and the degree of commitment from governments in different regions.

⁸⁶ The petrochemical industry will increasingly be a demand driver for oil. However, the impact of plastic pollution has become a major environmental issue impacting petrochemical demand.

⁸⁷ Aside from methane emissions which the industry will need to address increasingly urgently. In relation to LNG see Stern (2019).

Summary and Conclusions

Both in oil and gas markets, the transition from monopolistic to competitive markets has been associated with government policy (liberalisation in Europe and deregulation in the US and Canada) facilitated by a surplus of supply over demand. However, the liberalisation policies of the 1980s did not have the same effect on oil and gas markets. Mainly due to its physical characteristics, oil markets were already globalised in the 1950s and 1960s under control of monopoly structures erected by the oil Majors. When these structures started collapsing at the end of 1960s, and finally in the late 1970s, OPEC was unable to exert the same degree of control. Increased competition, rising supply and falling prices of oil in the mid-1980s coincided with the liberalisation policies in the UK and the US, creating fertile ground for global commoditisation of the oil trade. Three key oil benchmarks created in the 1980s – WTI, Brent and Dubai - saw exponential growth in trading and development of complex eco-systems of derivatives associated with them.

The development of the international oil markets has not been a smooth ride and each benchmark has had its problems and had to adapt and change. A significant drop in the domestic production in late 1980s in the US forced NYMEX to introduce an ‘alternative delivery’ option to keep the WTI contract functioning. The opposite happened in 2010s, when swelling volumes of shale oil could not find a home and caused the benchmark to decouple from the international markets again. The lifting of the export ban at the end of 2015 resolved that problem. The Brent benchmark has had a plethora of problems, primarily due to its falling production. Each time, a compromise was found by adding new grades and expanding the loading window being assessed. Dubai assessments in many ways shadowed developments in Brent for the very same reasons.⁸⁸

Similar liberalisation policies were much harder to implement in the highly regionalised gas markets of the 1980s. They resulted in creation of trading hubs such as US Henry Hub in the 1980s and the British NBP more than a decade later; a liberalised Continental European market only began in earnest in the 2010s with the Dutch TTF becoming the pre-eminent European hub by 2020. Pipeline gas and LNG are both pricing off, and trading around, the same delivery hubs. New players are emerging, many of them with the experience of oil trading and using this knowledge to translate it into the new gas ‘trading infrastructure’. Many oil companies have become oil and gas companies, and oil trading houses have turned into oil & gas traders. In terms of trading, gas has changed from a ‘poor relation’ to become an increasingly equal, and faster growing family member.⁸⁹

While both North America and Europe remain predominantly pipeline gas markets, the influence of LNG has grown partly because of the enormous increase in global supply with Qatar and Australia joined, in the 2010s, by the US and Russia. New project developments in these countries and others in north and east Africa look set to maintain the supply wave in the 2020s. LNG has always been the dominant force in Japanese, South Korean and Taiwanese gas markets, with China, India and many other Asian countries starting to import in the 2000s.

North American shale gas intensified LNG supply competition, challenging the existing players and pricing structures. While Henry hub-based pricing looked attractive and a welcome alternative to the traditional crude oil standard in Asia, by the end of the 2010s it had run into commercial problems. But the emergence of the Platts JKM LNG benchmark for derivatives and physical cargoes, portfolio players without long term downstream sales contracts, and the increase in the share of short-term contracts to around 35% of total trade, have fundamentally changed the LNG scene.

A deficit of supply of global LNG compared with demand caused very high European and Asian prices during 2011-15. This gave way to a more balanced market with more moderate prices up to 2018,

⁸⁸ See Imsirovic (2014).

⁸⁹ On December 19, 2019, the Intercontinental Exchange, Inc. (NYSE: ICE), a leading operator of global exchanges and clearing houses and provider of data and listings services, announced record open interest of 2.71 million contracts in Brent Crude Oil futures and 2.21 million contracts in TTF futures and options. As of December 17, and on a year-on-year basis, Brent Crude Oil futures open interest was up 22% versus the prior year, while open interest across TTF futures and options was up 73%.

followed by a strong surplus market with historically low prices in 2019-20. These developments have exposed fundamental inconsistencies of continuing to link Pacific LNG prices with crude oil. But in Asia, market liberalisation and national hub development are either developing very slowly or completely absent.

Just as in oil markets, large gas players will continue to lean towards forming natural monopolies through mergers, acquisitions, vertical and horizontal integration. The US, Russia, Norway, Australia and Qatar will be the most important exporting countries with Europe as the main stage for competition between (and among) pipeline and LNG suppliers, and Asia (mainly) for LNG supplier competition.⁹⁰ Portfolio gas players and aggregators will likely become the key 'price makers' in gas benchmarks, just like majors and traders have done in oil markets. And just like in oil markets, gas benchmarks will continue to grow in importance.

There are four main differences between oil and gas market organisation and price formation.

- There has never been an organisation of gas-exporting countries attempting to control volumes and/or prices, and it is doubtful there will ever be.⁹¹ OPEC's problems since the mid-2010s and its growing need for supply cooperation with others (OPEC+) has highlighted the difficulties this type of organisation has encountered.
- Oil markets developed regional benchmark prices – with Brent as a global benchmark – while gas prices were determined by long term contracts linked to oil in Europe and Asia. This resulted in market-based pricing for gas in arriving later - and in Europe much later - than in oil markets and was facilitated, once markets had liberalised, by the creation of regional hubs.
- Market-based pricing is still developing in Asia and will be accelerated by over-supply and very low prices, but national hubs are either absent or very slow to develop because of a lack of market liberalisation.
- As Asia progressively makes that transition, something akin to a global price of gas – but still heavily influenced by LNG transportation costs – will emerge. But gas prices will probably never achieve the global integration and sophistication of global oil prices because of the physical differences between the fuels, and differences in the end-use markets where they are sold.

⁹⁰ Canada is an important pipeline exporter to the US and has one LNG export project under construction but seems unlikely to become a major force in gas trade outside North America.

⁹¹ The Gas Exporting Countries Forum (GECF) has often been described as a potential 'OPEC for gas', however it has always denied any aspiration to play such a role. For its early history see El-Katiri and Honoré (2012).

Bibliography

- Allsopp, C. and Stern, J. (2012). 'The Future of Gas: what are the analytical issues related to pricing?' in Stern, J.P. ed. *The Pricing of Internationally Traded Gas*, OIES/OUP. Chapter 1.
- Ason, A. (2019). Price reviews and arbitrations in Asian LNG markets, OIES Paper NG 144.
- Ason, A. and Meidan, M. (2020). *Force majeure notices from Chinese LNG buyers: a prelude to renegotiation?* OIES: Oxford Energy Comment.
- BP (2019). *BP Statistical Review of World Energy 2019*. 68th Edition.
- BP (1977). *Our Industry Petroleum*.
- Corbeau, A-S. (2016). 'Conclusions', in Corbeau, A-S. and Ledesma, D. *LNG Markets in Transition: The Great Reconfiguration*, Oxford: OIES/OUP.
- Dale, S. and Fattouh, B. *Peak Oil Demand and Long-Run Oil Prices*, OIES Energy Insight 25, January 2018.
- El-Katiri, L and Honoré, A. (2012). 'The Gas Exporting Countries' Forum: global or regional cartelisation?' in Stern, J.P. ed. *The Pricing of Internationally Traded Gas*, OIES/OUP. Chapter 13.
- Fattouh B. (2010): *An Anatomy of the Crude Oil Pricing System*, OIES Paper WPM 40.
- Fattouh B. and Imsirovic A. (2020). Shocks and Differentials: How are oil markets coping? OIES Energy Comment.
- Fattouh B. and Imsirovic A. (2019). *Contracts for Difference and the Evolution of the Brent Complex*, OIES: Oxford Energy Comment.
- Financial Times: 'US Oil Price Crashes Beyond Zero as Coronavirus Crashes Demand', April 21, 2020.
- Flower, A. and Liao, J. (2012). 'LNG Pricing in Asia', in Stern, J.P. ed. *The Pricing of Internationally Traded Gas*, OIES/OUP. Chapter 11.
- Foss, M.M. (2012). 'Natural Gas Pricing in North America', in Stern, J.P. ed. *The Pricing of Internationally Traded Gas*, OIES/OUP. Chapter 3.
- Fulwood, M. (2019). *Are Asian LNG Spot Prices Finally Decoupling from oil?* OIES: Oxford Energy Comment.
- Fulwood, M. (2020a). *\$2 gas in Europe is here: who will blink first?* OIES: Oxford Energy Comment.
- Fulwood, M. (2020b). 'LNG FIDs in 2020 – is this The Final Countdown?' *OIES Quarterly Gas Review*, pp. 6-7, January 2020.
- GIIGNL (2020). *The LNG Industry: GIIGNL Annual Report 2020*.
- Heather (2010). The Evolution and Functioning of the Traded Gas Market in Britain, OIES Paper NG44.
- Heather (2015). *The Evolution of European Traded Gas Hubs*, OIES Paper NG104.
- Heather (2019). *European Traded Gas Hubs: a decade of change*, OIES Energy Insight 55.
- Heather (2020). 'Can the Platts JKM price and LNG MOC bring true liquidity to Asian gas markets?' *OIES Quarterly Gas Review*, January 2020, pp. 24-26.
- IEA (1998). *Natural Gas Pricing in Competitive Markets*, OECD/IEA.
- IEA (2013). *Developing a Natural Gas Trading Hub in Asia*, OECD/IEA.
- IEA (2019): *World Energy Outlook 2019*.

- IGU: International Gas Union, *Wholesale Price Survey* (various years), www.igu.org
- Imsirovic A. (2019). *Changes to the 'Dated Brent' benchmark: More to come*. OIES.
- Imsirovic A. (2014). *'Oil Markets in Transition and the Dubai Crude Oil Benchmark'* – OIES.
- Kumar, M. and Stern, J. (2020). *Gas Industry Reform and the Evolution of a Competitive Gas Market in Malaysia*, OIES Paper 158.
- Mabro R. and Horsnell P. (1993): *Oil Markets and Prices, The Brent market and the Formation of World Oil Prices*, OUP/OIES
- McGrandle L. (1975). *The Story of North Sea Oil*, Wayland 1975.
- McNally R. (2017). *Crude Volatility*, Columbia University Press.
- Meidan, M. (2019). *Glimpses of China's Energy Future*, OIES: Oxford Energy Comment.
- Mitchell, E. (1976). *Vertical integration in the oil industry*. Washington: American Enterprise Institute for Public Policy Research.
- Montague G. H. (1903). *'The Rise and the Progress of the Standard Oil Company'*. Leopold Classic Library, reprint.
- Odell, P.R. (1969). *Natural Gas in Western Europe: a case study in the economic geography of energy markets*, Haarlem: de Evren F. Bohn NV.
- O'Sullivan, S. (2019). *China's Natural Gas Development – reality check*, OIES: Oxford Energy Insight 62.
- Parra F. (2004). *Oil Politics, A Modern History of Petroleum*, Tauris & Co.
- Platts: *European Gas Daily – Monthly Averages Supplement*, S&P Global.
- Purvin & Gertz (2010). *The role of WTI as a crude oil benchmark*, Prepared for CME Group.
- Rogers, H. (2017). *Does the Portfolio Business Model Spell the End of Long-Term Oil Indexed Contracts?* OIES Energy Insight 10.
- Rogers, H.V. and Stern, J. (2014). *Challenges to JCC Pricing in Asian LNG Markets*, OIES Paper NG81.
- Sampson A. (1988). *The Seven Sisters'*, Coronet Books.
- Sharples, J. and Henderson, J. (2019). *Gazprom's Gas Sales via its Electronic Sales Platform*, OIES Energy Insight 51.
- Shell (2020): *Shell LNG Outlook 2020*,
- Stapczynski, S. *'Top LNG Buyers Seek Cargo Delays as Virus Slashes Demand'*, *Bloomberg*, April 16, 2020.
- Stern, J. (2019). *Challenges to the Future of LNG: decarbonisation, affordability and profitability*, OIES paper NG 152.
- Stern, J. (2016). *'LNG Pricing'* in Corbeau, A-S. and Ledesma, D. *LNG Markets in Transition: the great reconfiguration*, OIES/Kapsarc: OUP, Chapter 8.
- Stern, J. (2012). *'The Pricing of Gas in International Trade'*, in Stern, J.P. ed. *The Pricing of Internationally Traded Gas*, OIES/OUP. Chapter 2.
- Stern, J. and Rogers, H.V. (2014): *The Dynamics of a Liberalised European Gas Market*, OIES Paper NG94.
- Stern, J. and Rogers, H. (2013): *The Transition to Hub-Based Pricing in Continental Europe: A Response to Sergei Komlev of Gazprom Export*, Oxford Energy Comment, February 2013.

Stern, J. and Rogers, H. (2012). 'The Transition to Hub-Based Pricing in Continental Europe', in Stern, J.P. *The Pricing of Internationally Traded Gas*, OIES/OUP. Chapter 4.

Stern, J. and Yafimava, K. (2017). *The EU Competition Investigation into Gazprom's Sales to Central and Eastern Europe: a detailed analysis of the commitments and the way forward*, OIES Paper NG1211.

Tarbell, I. (2003). *The History of the Standard Oil Company*, Dover Publications.

The New Palgrave Dictionary of Economics (1998), The Macmillan Press Limited, London.

World Bank (1995). Discussion Papers: No. 301.

Yafimava, K. (2013): *The Third Energy Package for Gas and the Gas Target Model: major contentious issues inside and outside Europe*, OIES Paper NG75.

Yergin D. (1991). *The Prize*, Simon & Schuster.

Yermakov, V. and Henderson, J. (2020). *The New Deal for Oil Markets: Implications for Russia's short term tactics and long term strategy*, OIES Energy Insight 67.