Trends in global gas pricing

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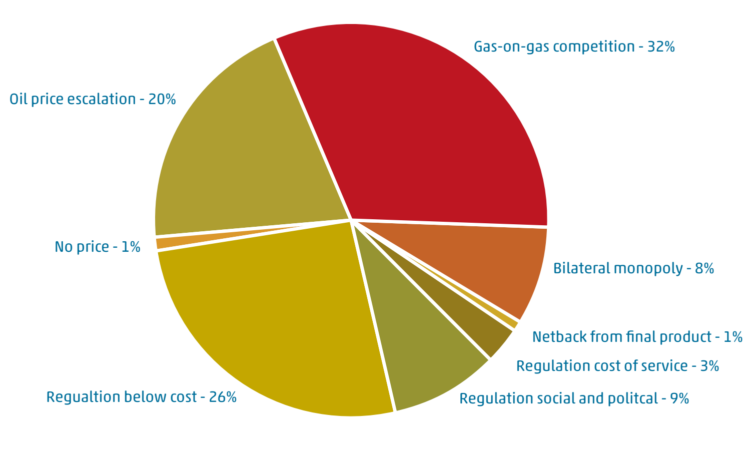
Oil and gas are both fluid hydrocarbons. Their exploration and development technologies are in general very similar and indeed in some circumstances they are both produced from the same well. With crude oil traded as a global commodity (albeit as benchmark regional blends) since the 1980s, one could be forgiven for assuming that natural gas would also have a global reference price. While this is not the case at present, this paper explores how a more 'price connected' future for gas may evolve in ways that will be the focus of detailed research by the Oxford Institute in 2012.

A world of difference in gas pricing

Natural gas suffers, however, from being, well, a gas, i.e. its energy per unit of volume (at atmospheric pressure) is only 0.1 per cent of that of liquid crude oil. Transporting and storing gas will involve higher infrastructure investment relative to oil. Liquefied Natural Gas (LNG) is gas that has been cryogenically cooled to minus 163 degrees Centigrade where it exists as a liquid at atmospheric pressure. In this state its energy per unit volume is 65 per cent of liquid crude oil and LNG can be shipped vast distances between the point of production and a destination market. This is only possible, however, through the construction and use of purpose-built liquefaction plant, loading and unloading facilities, insulated storage tanks and ocean going LNG tankers. At the destination market the LNG is re-gasified to enter the distribution grid. This supply chain is capital intensive and its construction confined to relatively few specialised contractors.

Figure 1: World gas price formation 2007 - total consumption



Source: IGU

Given its relatively high cost of transportation and storage, it is unsurprising that historically, natural gas production has tended to grow to supply nearby national and regional markets. Accordingly each developed its own approach to natural gas price formation. A comprehensive review of regional policies is contained in 'Wholesale Gas Price Formation – A global review of drivers and regional trends' by the International Gas Union, as shown in Figure 1. While 52 per cent of global gas consumption is priced on the basis of gas on gas competition or by reference to oil or oil products prices, much of the remainder is regulated, often at levels significantly below those prevailing in the OECD markets of Europe and North America. This is illustrated dramatically in Figure 2 which shows that in 2009 gas prices in the Middle East, Latin America, Africa and the CIS were in the range US$0.80/mmbtu to US$2.50/mmbtu, levels significantly below the world average of US$4.00/mmbtu.

The rise of the long-distance gas trade

As growing regional gas markets outpaced the availability of indigenous and proximate supplies the growth of 'long distance' gas (trade-flows of pipeline gas and LNG) became established. This is shown in Figure 3. Long distance gas is classified as LNG (blue) and pipeline trade-flows from Russia, North Africa, Iran and Azerbaijan into Europe and pipeline flows within Asia and South America (red). In the period 1995-2010 both grew with LNG on a continuous trajectory. The recent economic recession resulted in a fall in global gas consumption and pipeline trade-flows in 2009. However, LNG consumption increased markedly over 2008 levels in 2009 and 2010.

The main regional markets impacted (or potentially impacted) by the growth in long-distance gas are North America (US, Canada and Mexico), Europe and the main LNG importing countries of Asia (Japan, South Korea, Taiwan, China and India). The intriguing question is "given the differing mechanisms of price formation in each region, what happens when you 'plug them together' with long distance gas?"

To explore this we need to understand how gas pricing is formulated in each of the regions and the nature and degree of flexibility of pipeline gas and LNG.

Regional price formation

North America

Gas prices in the US are in the first instance driven by gas on gas competition and are discoverable at the many regional trading hubs. The best known is Henry Hub (HH) which is viewed as the marker for US natural gas prices. The US has a 'porous' gas trade border with Canada and Mexico, both of which have prices influenced by the US market. Due to the potential for inter-fuel competition in the power generation sector, gas prices can at times be influenced by residual fuel oil. However, this has not been a factor since 2006. In the expectation that the US would require significant LNG imports some 125 bcm a year of LNG regasification capacity was built in the mid to late 2000s. With the dramatic growth in shale gas production since 2006, re-gas utilisation rates are extremely low and the industry is currently pursuing the conversion some of these facilities to LNG export facilities.

Europe

With the exception of the UK market which became liberalised in the 1990s, Europe began the 2000s with a market structure dominated by long-term oil indexed contracts for its pipeline and LNG imports and also its domestic production. Pipeline gas purchased under long term contracts from Russia and North Africa is priced according to formulae which include six to nine month rolling averages of gasoil and fuel oil prices. The pricing terms are subject to periodic review (typically every three years) and may be amended through negotiation. The buyer commits to buy at a minimum the 'Take or Pay' level (TOP) within a contract year running from October to September of the following calendar year. The take or pay level is typically 85 per cent of the Annual Contract Quantity (ACQ).

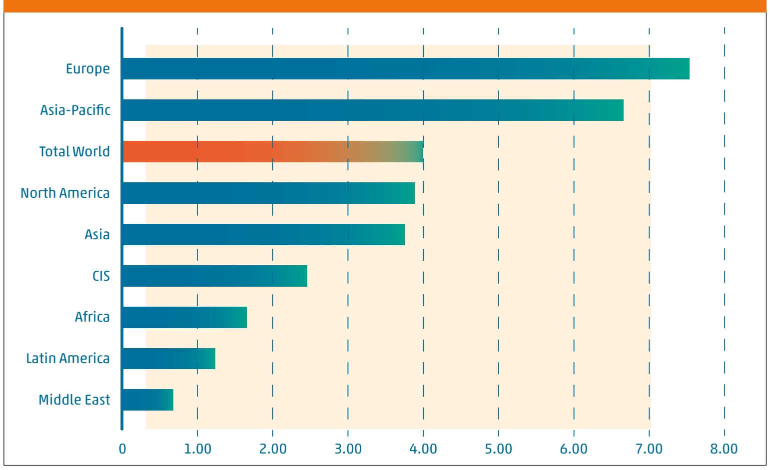
Gas market liberalisation in continental Europe has been a slow and tortuous process. However, the gas demand reduction caused by the economic recession coinciding with a rapid growth in LNG supply from Qatar has resulted in vigorous activity in the nascent gas trading hubs of Northern Europe and a growing challenge to the oil-indexed paradigm for gas pricing. A buyer of gas in Continental Europe can choose whether or not their requirements for gas above the oil-indexed contract Take or Pay level can be met by optional additional oil indexed contract gas or 'spot' gas purchased on a trading hub (much of which physically originated from the UK market via the UK-Belgium Interconnector pipeline). When conditions for arbitrage have been favourable this has resulted in period of price convergence between UK gas prices and those linked to oil products prices on the European continent.

Asian LNG markets

The majority of LNG trade flows in Asia are sold under long-term contracts with price related by formulae to a time-averaged value of crude oil. The coefficient linking LNG prices to oil prices differs between contracts and some contracts also contain price ceilings and floors or an 'S' curve which moderates the more extreme oil price impact on the LNG price. Asian importers also purchase spot LNG cargoes to supplement contracted supplies. Unlike the situation in Europe, there is no explicit provision in these contracts for a periodic price review. Each contract pricing formula is in effect 'fossilised' for the life of the contract – a 'snapshot' of the negotiated view of buyer and seller as to how the future LNG price should respond to oil price. Over time the differences in formulae relating LNG prices to oil price have led to a wide range of LNG contract prices. In 2004 contract prices were reasonably bounded but in 2011 the spread is between US$4/mmbtu to US$15/mmbtu.

The spread of Asian LNG contract prices also means that there is no obvious regional benchmark for spot →

Figure 2: Average wholesale gas prices by region, 2009



Source: Mike Fulwood, 2009 IGU Survey of Wholesale Gas Prices

LNG cargoes purchased. In the absence of an obvious alternative, Asian spot LNG cargoes are often priced relative to the UK gas price (National Balacing Point) plus a margin which presumably reflects a distance-related shipping cost and possibly, as the market becomes tighter, a further premium to attract cargoes.

The flexibility of LNG

In order to consider how the regional markets of North America, Europe and the Asian LNG importing markets might behave when 'plugged together' let us first consider the flexibility of LNG supply. The majority of LNG is sold under long term contracts. However, the trend has been towards more flexible arrangements.

Even LNG under long term contract can be diverted if the contract buyer and seller agree to divert cargoes for a higher sales price and share the proceeds. This is especially the case in European LNG supply contracts.

Interaction between regional gas markets

The schematic in Figure 4 is a depiction of the gas markets of North America, Europe and the Asian LNG Importing markets in 2011. Global LNG supply is represented by the tap at the top of the diagram. The Asian markets are assumed to take whatever LNG they require to meet their demand (Japan, Korea and Taiwan having no other sources of natural gas). The remaining LNG is available for Europe and North America. At the moment however, due to the growth of shale gas production in the US, North America only takes minimal quantities of LNG. Europe is thus absorbing the balance by virtue of its ability to reduce pipeline imports of oil-indexed gas to Take or Pay levels.

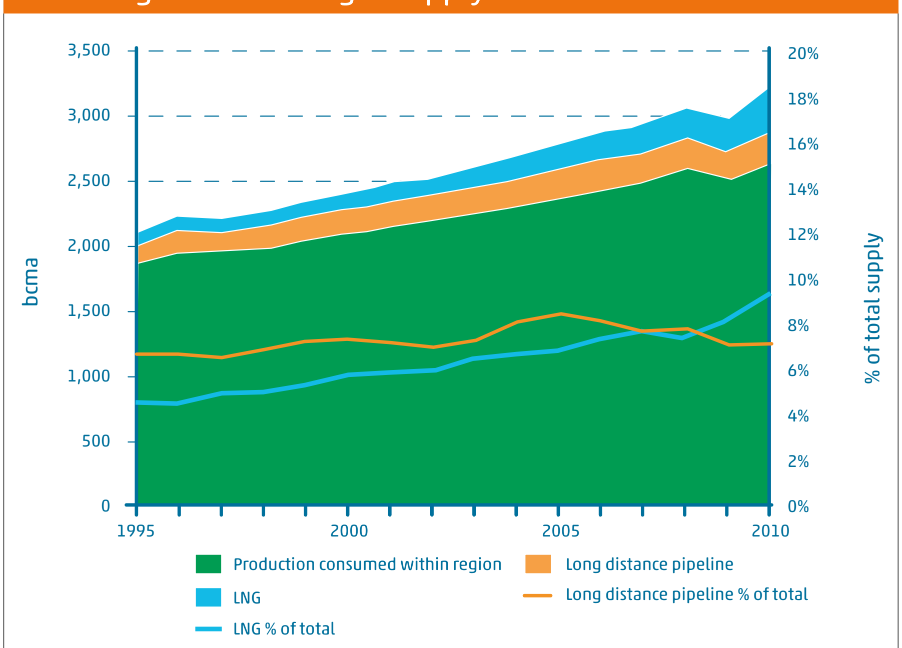
What we have in this situation in mid-2011 is:

- North America as an isolated, self-sufficient gas market with prices around US$4.50/mmbtu.
- A 'hybrid' European market with traded hub spot prices at US$9/mmbtu and oil indexed contract prices at US$11/mmbtu to US$12/mmbtu, with buyers trying to satisfy their contract TOP commitments whilst maximising their take of cheaper spot gas.
- Asia with a range of LNG contract prices from US$4/mmbtu to US$15/mmbtu with supply supplemented by spot cargoes at a price of around US$12/mmbtu, apparently linked to European hub spot prices with a transport margin and premium.

The next stage of the evolution of the system depends crucially upon the US and the future trajectory of US shale gas production. Proponents of US shale gas see potential for supply growth well in excess of the country's consumption requirements. A number of LNG export projects are under active consideration. The economics of exporting LNG from the US appear to require a price difference of some US$3.50/mmbtu between US natural gas prices and those of the destination market. In broad terms US$2.00/mmbtu for the cost of the liquefaction plant, US$1.00/mmbtu for shipping and US$0.50/mmbtu for regasification at the destination market. If enough LNG export capacity is built for the 'system' to reach equilibrium, the outcome (probably around 2020) would be:

In **Europe** (if oil indexed contracts survive) gas prices

Figure 3: Global gas supply channels 1995 - 2010



Source: BP Statistical Review of World Energy 2011, Own Analysis would be determined by the present two tier arrangement where hub spot prices are either below oil-indexed pipeline import contract prices (as they are in 2011) or above them (due to tight market conditions); or, in a balanced market, hub and oil-indexed prices converged through arbitrage. If long-term contracts transition to adopt hubs as their pricing basis, European prices would be driven in the first instance by supply-demand considerations.

Asia's oil indexed LNG contracts would continue to exhibit a wide price range, The interesting question is whether the LNG spot market becomes deeper and more liquid. Whilst Asia might continue to use European hub prices as a reference, the competition between Europe and Asia for spot cargoes would in turn influence European hub prices.

In North America, assuming regulatory authorities do not limit the scale of LNG exports, US prices could be expected to stabilise at a level US$3.50/mmbtu below European hub prices.

If however, as some commentators expect, US shale production is unable to fulfil the potential described above, the US will at some point revert back to being an importer of LNG. The outcome (again probably around 2020) would entail active LNG arbitrage between Europe and North American. In this alternative view of 2020, US prices could converge with those of Europe in periods where Europe was able to close the price gap though arbitrage by optimising LNG and pipeline imports. In practice there would probably be a differential LNG transportation cost difference of between US$0.50/mmbtu and US$1.00/mmbtu. European pipeline import volume constraints and the need to meet Take or Pay commitments would at times, however, prevent arbitrage from closing the price gap. If oil-indexed contracts survive in Europe the net effect would be an arbitrage dynamic which would seek to bring US prices up to oil-indexed levels where physical factors permitted this.

Conclusions

The discussion of the potential for greater pricing linkage between regional gas markets broadly in the 2020 timeframe above is predicated upon the dynamic interaction between the liberalised markets of North America and the UK and the newly formed trading hubs of Continental Europe. The key medium-term uncertainty relates to the future performance of US shale gas and whether this results in North America becoming a net exporter or importer of LNG.

We are at present in the midst of an evolution in the nature of natural gas markets where, despite the inherent high costs of transporting and storing this commodity, differences in price level between regional markets provide a strong motivation for arbitrage via flexible LNG. As such arbitrage plays develop and intensify we may also expect to see a 'Darwinian' competition between oil indexation and hub-based pricing systems. For now such a competition is likely to be confined to Europe. However in time, through a deepening of its LNG spot market such changes may also influence the Asian market.

Figure 4: System dynamics 2011