
European Natural Gas Prices

Howard V Rogers

Introduction

There are two types of gas sold in Europe. Their appearance and physical characteristics are identical; the only difference is the way in which they are priced. This summer, pipeline gas from Russia and North Africa was selling at around \$8/mmbtu, while traded or 'spot' gas in the UK was selling for around \$3/mmbtu. The fact that the same commodity should be the subject of such extreme price variation raises three questions:

- How has the market architecture developed to allow such disparities to arise?
- What are the forces currently applying stresses to this structure?
- Is such a system sustainable?

The Evolution of the European Gas Market's Structure

The structure of the continental European natural gas market was initially shaped and subsequently heavily influenced by the seemingly simple question of how to formulate the price of gas from the Groningen Field discovered in Holland. Given the low cost base of this relatively shallow onshore reservoir, gas from Groningen, after lengthy consideration, was priced, not on the basis of its underlying cost of supply but on the basis of competitiveness with the final consumer's alternative non-gas fuels. This is often termed the 'market value principle' or alternatively the 'netback market approach'.

This same approach was subsequently adopted for contracted pipeline imports to continental Europe from Russia and North Africa. Contracts for European pipeline imports initiated from the 1970s, were typically 20 to 25 years in duration. The buyer had the right to nominate up to an annual amount (the Annual Contract Quantity – or ‘ACQ’) but had to take or, in any case, pay for a quantity equal to the ‘Take-or-Pay’ level (‘TOP’), which is typically some 80–85 percent of the ACQ on a contract year basis. Additional flexibility was applied at the monthly or daily level provided that, in the course of a gas contract year, an amount at least equal to the TOP was paid for.

Pricing of long-term contracted gas imports is generally linked by formula to gas oil and fuel oil, by a formula negotiated and defined in the contract:

$$P_n = P_0 \times (a \times \text{av} (F(n-x) + \dots + F(n-1)) + b \times \text{av} (G(n-x) + \dots + G(n-1)) + c)$$

The price in month n equals the initial contract price multiplied by:

- A constant a multiplied by the average of the last x months Fuel oil (F) prices,
- A constant b multiplied by the average of the last x months Gas oil (G) prices plus
- A constant c .

The values of the key variables are confidential to the parties to the contract, however they have over time been inferred, in aggregate, from border price data. These contracts also provide for periodic price re-negotiation or ‘price re-openers’ if market conditions change significantly. For this reason, in continental Europe there is a significant level of price similarity in contract gas from different sources. This was not historically the case in the UK, where contracts did not provide for price re-opener negotiations.

In the UK, cost-based pricing was the main principle used in the negotiation of contracts between the state monopoly buyer British Gas and upstream producers in the pre-liberalisation era (pre-1996). This led to a wide range of contract prices depending on the cost base and gas/liquids production ratio of field-specific contracts negotiated. During the 1990s, successive legislative acts served to progressively undermine this position, critically enabling upstream producers to sell gas directly to the large power users. This catalysed the monetisation of the ‘backlog’ of undeveloped discoveries, which subsequently competed aggressively for customers in the power and industrial sectors. British Gas’s market share loss was such that it was unable to sell on its Take-or-Pay levels under field-specific long-term contracts that were priced ‘out of the market’.

Facing significant financial exposure British Gas was forced to re-negotiate many of these contracts at lower price levels and to transform them to non-field specific long-term supply contracts. The UK market now comprises a mixture of these old ‘legacy’ contracts and spot gas which is sold at the National Balancing Point (NBP) – the UK’s only hub. Although possibly some 25 percent of UK production is still sold under ‘legacy’ supply contracts the disparate pricing formulae have resulted in a significant degree of scatter and,

as a result, these do not noticeably influence the traded UK gas price. The UK market became effectively liberalised in the mid 1990s with the NBP becoming a virtual hub.

Despite the moves to liberalise the continental European gas market it is still, in the author’s opinion, in a state of ‘semi-suspended animation’: held back by the interests of its gas market incumbents who have little incentive to change and whose long-term contractual arrangements with suppliers in Russia and North Africa are difficult to reconcile with the liberalised gas market model epitomised by the UK and North America. Since the liberalisation of the UK gas market, Europe has had what can best be described as a ‘Hybrid’ market. In the UK, gas prices at the NBP are primarily determined by supply and demand. Across the Channel, in continental Europe, the territory is dominated by traditional long-term pipeline supply contracts with gas prices determined by formulae incorporating a 6 to 9 month rolling average of gas oil and fuel oil prices.

A crucial development in recent years has been the establishment of trading hubs in northern continental Europe in Zeebrugge, (at the end of the UK–Belgium Interconnector pipeline), and in France, The Netherlands and Germany. Initially it is arguable that such hubs were created in the early 2000s solely by the ‘overflow’ of excess UK domestic production during the summer months when (as a consequence of its low provision of seasonal storage capacity and a liberalised market), the UK found willing buyers for summer spot gas. As the UK’s domestic production began to decline (post 2001), it was to be expected that these ‘satellite’ hubs would literally ‘dry-up’, starved of spot gas supply.

This outcome has been averted by the development of the Norwegian Ormen Lange field and the associated Langeled pipeline to the UK. This provides Norway with an alternative to selling oil-indexed gas at the Continental European ‘beach’; specifically the option to sell Ormen Lange, and any gas not nominated by Continental European buyers, into the UK traded market at prevailing spot prices. However, this may well result in Norwegian gas ‘at the margin’ overflowing through the interconnector into the Continental market via Belgium. Similarly the BBL (Balgzand Bacton Line) from the Netherlands is ‘at the margin’ flowing gas from the Netherlands into the UK and then back out again to Belgium.

Contrary to the ‘Old School’ logic that long-term contracts are a pre-requisite to the construction of significant import infrastructure, the UK with a good track record on pragmatic, limited Third Party Access exemption, has succeeded in building sufficient pipeline and LNG import capacity to see it through the medium term. LNG imports into the UK will also become a major source of spot gas supply for trading hubs in northern Continental Europe.

So far so good. The European Market ‘hybrid’ system can remain ‘stable’ and a liberalised UK market and satellite hubs can co-exist with the long-term contract paradigm as long as the following ‘rules of engagement’ hold:

- Continental European pipeline gas import contract prices adhere to the contractual formulae based on a time-averaged relationship to gas oil and fuel oil (as asserted by supplier countries to Europe).

- Continental buyers/midstream players can engage in hub trading and LNG diversions as long as they honour their Take-or-Pay commitments under the long-term pipeline gas contracts.

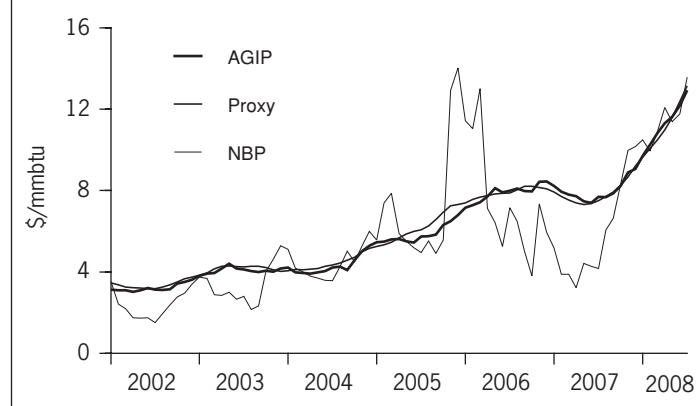
Clearly the greater the absolute price of oil-indexed gas and the size of the differential between this price and that of UK/Continental hub spot gas prices, the more these 'rules of engagement' are in conflict with the temptation for 'enlightened self interest' for key players i.e. end consumers seeking to purchase cheaper 'spot gas' in preference to oil-indexed supplies.

With the high oil prices in the second half of 2008 and the economic-recession driven low demand (and hence low spot gas prices) prevailing in 2009 the strains on the 'rules of engagement' have never been so severe. Will they prevail? Here are two reasons that suggest the edifice is beginning to crumble.

The AGIP Price Mystery

The Average German Import Price (AGIP) is disclosed by the German Federal Ministry of Economics and Technology. It is the average price of gas purchased under bundles of contracts with Russia, Norway, The Netherlands and an 'Other' category – primarily Denmark and the UK (which may well be spot-priced gas). The AGIP 'actual' price is reported typically 2 to 3 months 'old'. In order to try to predict future oil-indexed prices, analysts have used 'proxy' formulae to derive indicative future values, based on the format described at the beginning of this article. Figure 1 shows the actual NBP and AGIP prices and also the 'Proxy' values produced by 'tuning' an approximate formula.

Figure 1: UK, German and Proxy Prices 2002–2008

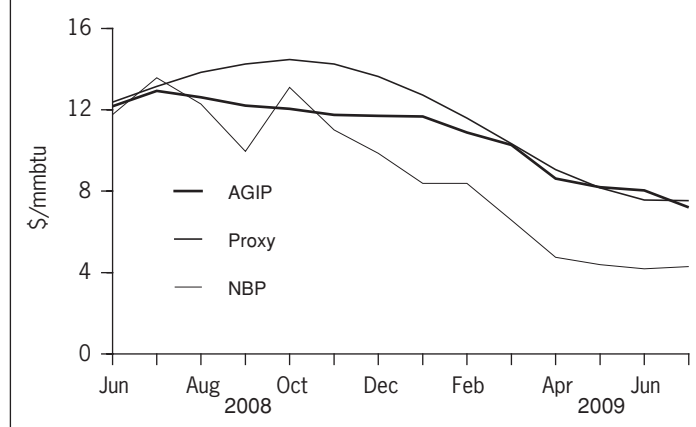


For much of the period the Proxy price has a reasonable 'fit' to the Actual AGIP price. Also of note is the periodic convergence of UK (NBP) price to AGIP – due to arbitrage at the trading hubs with oil-indexed gas. Periods of extreme high NBP prices in late 2005/early 2006 were due to a combination of a generally tight market for spot gas and LNG combined with the subsequent operational problems with the UK's main seasonal storage facility. The period of low NBP

prices in 2006 and 2007 coincided with the advent of new supplies of Norwegian gas via the Langeled pipeline. In the first half of 2008, arbitrage kept NBP very close to AGIP, which in turn was being driven by the rapid rise in oil and oil product prices.

Now let's take this on to the period June 2008 to the present (Figure 2). From August 2008 to March 2009 AGIP tracked a path that was at times some \$2/mmbtu lower than the Proxy prediction would suggest. From March 2009 onwards the previous relationship appears to have re-established itself.

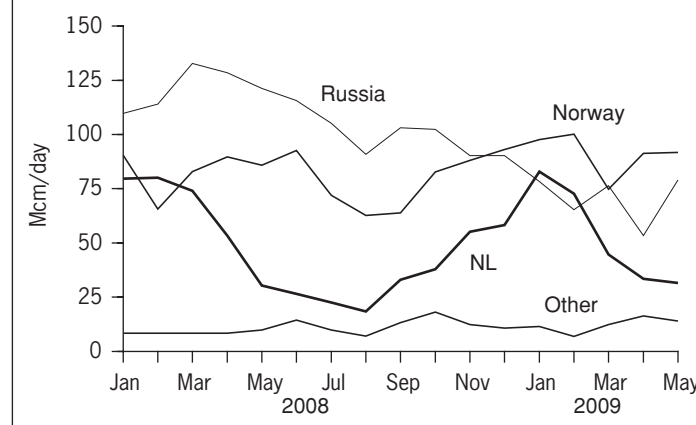
Figure 2: UK, German and Proxy Prices 2008–2009



Looking at the relative scale of gas imports from different supplier countries shown in Figure 3 provides no explanation. The relatively low scale of gas imports in the 'other' category is insufficient to cause this price dip, even if this was all UK spot gas. Gas imports from the Netherlands were high during this period – but on a par with those of a year earlier when no such discrepancy between AGIP and the Proxy prediction was evident.

In the absence of further clues one can only assume that one or more of Russia, Norway and the Netherlands in the period August 2008 to February 2009 reduced its gas sales price substantially below contractually agreed levels.

Figure 3: German Gas Imports



The Take or Pay Conundrum

There have been widespread media stories concerning the apparent failure of European buyers to have met their Take-or-Pay volume purchases of Russian oil-indexed pipeline gas imports for the contract year ending on 30 September 2009. Estimates, based on inferred actual imports for Russia, Algeria, Libya, Azerbaijan and Iran in aggregate to June 2009 and best estimates to September, imply that for the contract year 2008/2009 importers will collectively have imported around 10 percent less than their Take-or-Pay obligation (this adjusted for the gas which was not available due to the Russia-Ukraine dispute in January 2009).

Clearly the stakes are high and involve more than just

payment for the under-lifted volumes. As the earlier gas price graph showed (Figure 2) oil indexed prices are around twice the level of UK spot prices. If Russia were to make major concessions on Take-or-Pay levels this would, subject to infrastructure constraints, increase the scope for penetration into the European market of LNG pricing off Henry Hub and/or NBP.

The two developments described above represent either a 'hiccup' or signs of major structural subsidence in the long-standing European oil-indexed contract paradigm. Without a sudden resurgence in demand in Asia or Europe to levels above those of 2008, the additional LNG supply coming on-stream in the next two years will continue to exert severe 'stress testing' of Europe's 'Hybrid' natural gas market.