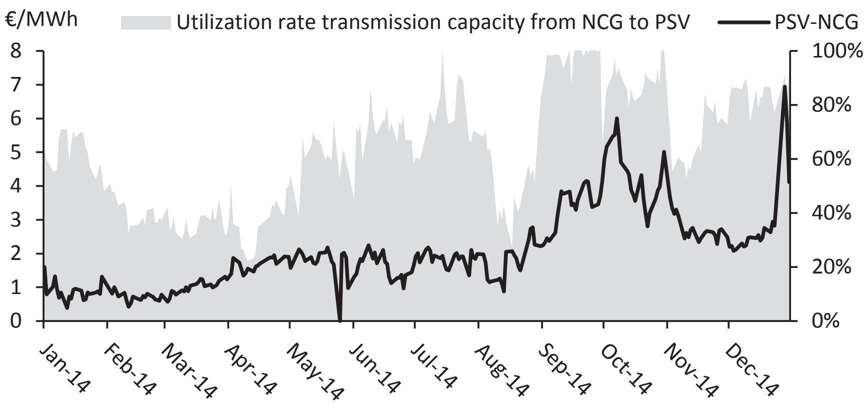

Figure 1.7. PSV–NCG OTC day-ahead price spread (€/MWh) and utilization rate of the transmission capacity from NCG to PSV (%)

Source: Tankard Parties, ENTSOG Transparency Platform, ENTSOG Capacity Map

Nexant data) more than 60 per cent of consumption in the countries with the less aligned hubs (France, Italy, and Austria) is priced on the basis of gas-on-gas competition.

Physical congestion between Germany and Austria resulted in an additional gas procurement cost in 2014 of about €60 million, most of which was accounted for by CEGH prices being higher than NCG in September and October 2014. Although the total volumes of gas sold at hub-based prices at PEGS are similar to those at CEGH, the wider de-linkage of prices in the south of France compared to those at the adjacent PEGN translated into a cost of €240 million. The size of the Italian market meant that, in 2014, barriers to flow into PSV resulted in an estimated increase in purchase costs of €330 million. These costs were incurred mostly in September–December, when the average premium over NCG exceeded €2/MWh (although for most of the time the cross border capacity was not fully utilized).

Summary and conclusions

In summary, it is increasingly difficult to deny the fact that hub prices represent market (supply–demand) prices in Europe. Price correlation across the North West hubs is almost perfect, and central Europe and Italy have improved significantly over the past five years. Some price disconnection still occurs in Austria, France and Italy for both physical and contractual reasons, but this issue is likely to be addressed by building new infrastructure and enforcing rules on congestion management procedures. However, it needs to be stressed that this article has focused on North West Europe, Central Europe, and Italy. In Spain and South East Europe, hub development is still at an early stage or absent. Once again, however, new infrastructure and, in particular, planned interconnections with markets further north, can be expected to align these markets with hub prices over the next several years.

Europe, prices and demand: key producers are maximizing rent

Thierry Bros

Russia and Norway both have market power in European gas. With more than a 50 per cent gas market share in Europe combined, they have theoretically more power in the European gas market than OPEC has in the oil market. The latter provides 32 per cent of the global oil supply (Figure 2.1).

'… IT IS INCREASINGLY DIFFICULT TO DENY THE FACT THAT HUB PRICES REPRESENT MARKET (SUPPLY–DEMAND) PRICES IN EUROPE.'

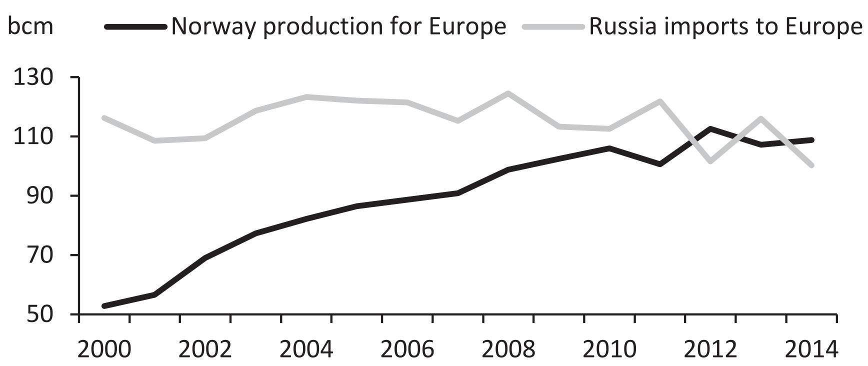

Figure 2.1. Russia and Norway gas supply to Europe, 2000–14

Source: SG Cross Asset Research/Commodities, IEA

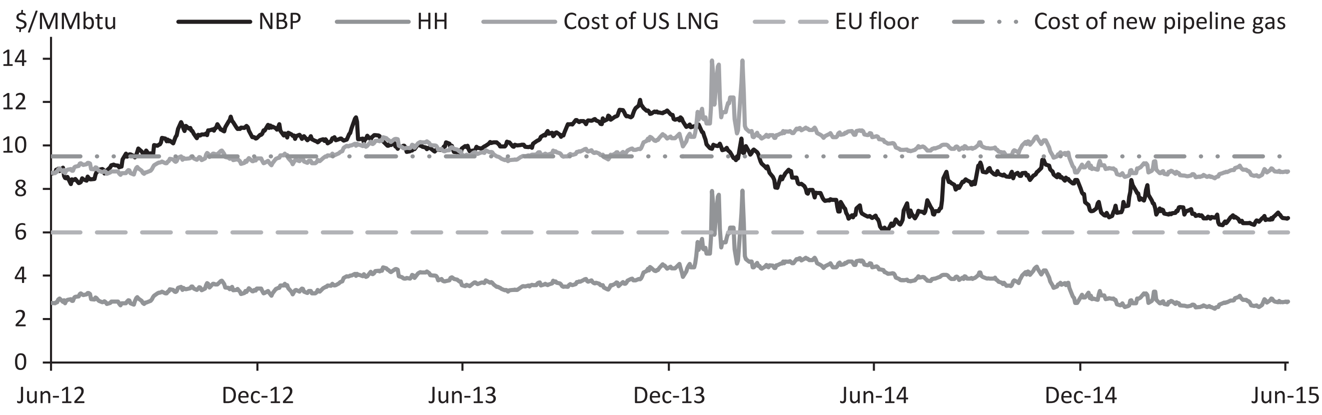

Figure 2.2. NBP to stay in a tunnel between the EU floor and the incentive price for new gas

Source: SG Cross Asset Research/Commodities, Datastream

By not pushing volumes too much, Gazprom (Russia) and Statoil (Norway) have not only avoided a price war but, since 2010, have managed to reset spot prices at a level acceptable to them, even if the move away from oil-indexation is continuing, with 61 per cent of European gas sold at hub-based prices in 2014 (IGU).

The author believes that both Russia and Norway have a vested interest in keeping gas prices in Europe between a floor estimated at $6/MMBtu and a ceiling that is either the cost of new gas (estimated at $9.5/MMBtu for pipeline gas from the Caspian Sea) or Henry Hub + $6/MMBtu for US LNG (Figure 2.2).

High Russian gas supplies in early 2014 demonstrated that new Final Investment Decisions for alternative supply were not needed. This allowed Europe to start the 2014/15 winter season with record storage levels, mitigating the potential risk of Russia–Ukraine-induced supply disruptions. As this risk didn't materialize, Gazprom reduced supply in Q4 2014 to a record low level to avoid a crash in hub prices.

With the fall in oil prices filtering through to long-term oil-indexed gas contracts, Gazprom has increased its export volume since March 2015. With Brent priced at around $60/bbl, some oil-indexed contracts with a low slope (around 10 per cent) will provide a cheaper price than the spot market this summer, hence Gazprom's forecast of increased Russian volumes for the remainder of 2015. The tricky question that remains is how to transport this gas to Europe, as Gazprom failed to get an exemption from the European Commission in December 2014 that would have allowed it to use 100 per cent of the capacity of the OPAL gas pipeline (35 bcm/year). Under the rules of the Third Energy Package, Gazprom is permitted to use only 50 per cent of the existing OPAL capacity and must reserve up to 50 per cent of pipeline capacity for gas transportation by independent gas suppliers. In April 2015, Gazprom started legal action in Germany (ongoing) to be allowed to use more than the permitted 50 per cent capacity of the OPAL pipeline.

Less Groningen gas means even more Russian gas and higher prices

In June 2015, Dutch Economy Minister Henk Kamp ordered a further tightening of production at Groningen, Europe's largest gas field, in response to a spate of earthquakes that have caused extensive property damage in this province. Output at the field will be capped at 30 bcm for the whole of 2015 (this figure was 42.5 bcm in 2014).

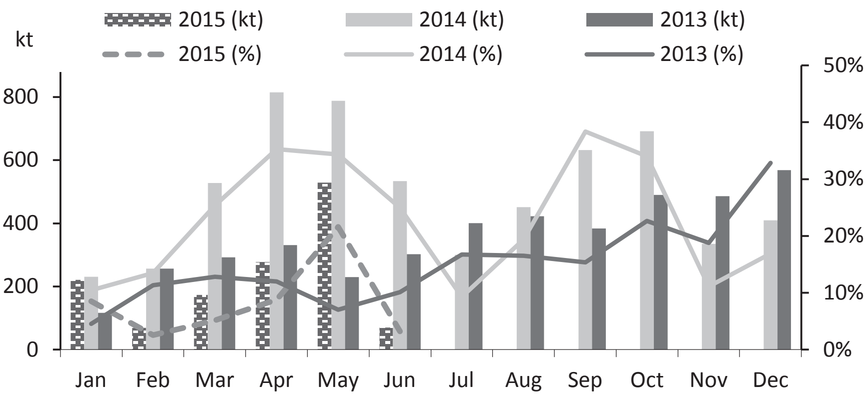

Figure 2.3. LNG re-exports from Europe, 2013–15 (% figures show reloading vs total LNG supply to Europe)

Source: SG Cross Asset Research, Waterborne

The direct beneficiary of lower European production is Russia, which has huge spare capacity and can respond to any unexpected impact on the supply–demand balance.

We will thus need more Russian gas year on year from Q3 15 to Q1 16 to mitigate the Groningen decision. However, the DG COMP restriction that Gazprom may not book more than 50 per cent of OPAL capacity means that more Russian gas will therefore need to transit via Ukraine at the end of the year. The current geopolitical stand-off between Ukraine and Russia is still tense, with renewed EU sanctions on Russia in place for another six months until the end of January 2016. Hence, the price outlook is bullish for winter 2015/16.

LNG back to Europe

Europe is, and will continue to be, the 'dumping' ground for excess LNG. Since February 2015 we have witnessed a severe drop in re-exports. With NBP and spot LNG in Asia being on par, we are also seeing an increase in LNG berthing in Europe (+27 per cent in January–June 2015 compared with the same period last year) (Figure 2.3).

This tendency of low re-export levels from Europe should become the new normal. The tightness of the LNG market following the Fukushima disaster is now history. But this extra LNG (8 bcm in 2015 vs 2014) represents only 64 per cent of the reduction of the Groningen cap (–12.5 bcm from 2014 to 2015) and will therefore not change the market power in Europe.

Prices are keeping European demand muted

Since 2006, European primary energy consumption has been reduced by 12.1 per cent and this trend is unlikely to change as Europe becomes more and more energy efficient (Figure 2.4).

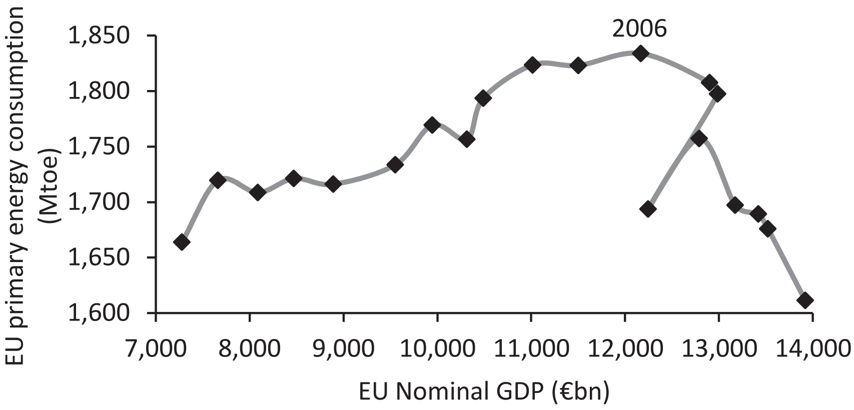

Figure 2.4. EU primary energy consumption vs nominal GDP, 1995–2014

Sources: SG Cross Asset Research/Commodities, BP Statistical Review, Eurostat

The strategic mistake made by European utilities was to disregard the 2007 political agreement that set the 2020 climate and energy objectives. By thinking that the secular energy growth trend was going to continue forever, their business model prompted them to overinvest in new power plants (in particular thermal). New thermal plants are a legacy of investment decisions dating back to the last decade, when companies denied the energy transition concept. Even with the closure of nuclear plants that happened overnight in Germany post Fukushima, the degree of over-capacity in generation was so significant that many plants needed, and still need, to be idled / mothballed / closed. This has hit gas-fired plants in particular, since gas was the higher-priced fossil fuel. If utilities had realized that energy transition would mean lower thermal generation demand, they would have invested less and would then have had to close fewer plants (and, in this case, perhaps the older coal plants would thus have been retired first).

As Europe is promoting renewables rather than fossil fuels, and as the floor for the gas price is too high to allow gas to compete with coal in power generation, European gas demand will be mostly weather-driven with an underlying downward trend driven by

Figure 2.5. Gas demand for Europe OECD excluding Turkey

Sources: SG Cross Asset Research, IEA for historical data continued efficiencies (Figure 2.5). The estimated 2015 increase in demand is only due to an assumption of normal weather in comparison to an abnormally warm 2014. The increased UK carbon tax (£18/t from 1 April 2015 vs £9.55/t previously) could also marginally help gas used for power generation in the UK but, for the rest of Europe, coal is still the cheapest fossil fuel for power generation.

With more than 15 liquefaction plants in construction (mostly in Australia and the USA), an LNG supply surge will hit Europe, with imports forecast to double between 2014 and 2020. With demand and domestic production both declining, this wave of LNG is to be welcomed as Gazprom has no wish to renew its transit contract via Ukraine (expiring on 31 December 2019) while European institutions and companies will not accept taking delivery of these volumes at the Turkish border (an option suggested by Gazprom, which wants to build the Turkish Stream pipeline instead of the now cancelled South Stream). Gazprom will continue to be the swing supplier, while Norwegian production will stay flat for the 2016–20 period (Figure 2.6).

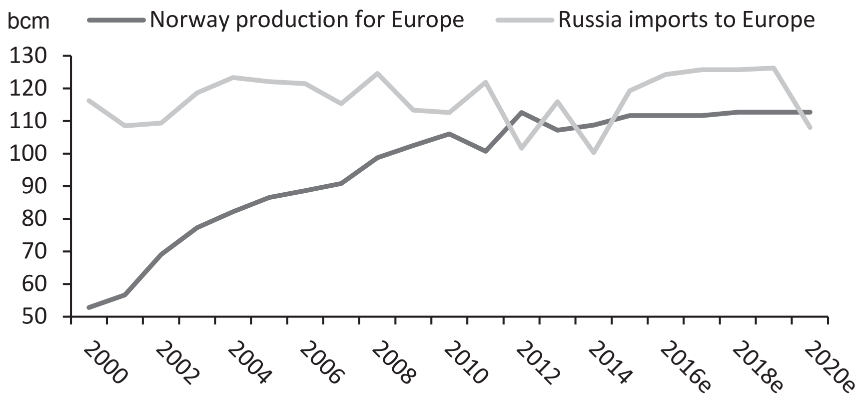

Figure 2.6. Russia and Norway supply to Europe, 2000 to 2020

Sources: SG Cross Asset Research/Commodities, IEA for historical data

However, if more LNG plants (above the five already in construction) go ahead in the USA in the next two years, this could lead to a price war in Europe as Gazprom will not accept a reduction in its export volumes below the 100 bcm level. European prices could then be reduced to a level at which US liquefaction plants could be mothballed.

Gazprom: a long march to market-based pricing in Europe?

Jonathan Stern

Europe: from oil-linked to hub-based gas pricing

For several decades up to the late 2000s, the netback market pricing formula – which links gas prices (principally) to oil product prices – dominated international gas transactions in Europe. This type of price formation is consistent with charging different prices to different national markets, as well as to different end-use sectors within the same market, depending on: their location, the fuels which compete with gas in their energy markets, and their ability to access alternative gas supplies (which was severely limited prior to the introduction of liberalization and competition). The formula institutionalized the practice of discriminating monopoly pricing – charging the highest possible price just short of a level which would cause customers to switch to other fuels and thereby maximizing the returns from sales to different markets – which was practised by all gas sellers (and European utility companies) prior to the arrival of competition.

When European gas demand crashed in the recession following the 2008 global financial crisis, many European utilities struggled to meet the minimum take-or-pay (ToP) commitments in their long-term contracts at oil product-linked prices, at a time when crude prices were rising to $100/bbl. The resulting surplus of gas was a key factor in creating a hub-priced gas market; this situation subsequently evolved to a point where the International Gas Union estimates that in 2014, more than 60 per cent of European gas was sold at hub-based prices, rising to nearly 90 per cent in the north-west of the Continent.

'… IN 2014, MORE THAN 60 PER CENT OF EUROPEAN GAS WAS SOLD AT HUB-BASED PRICES …'

The impact of these developments was of special significance for Gazprom because of the size and centrality of its supplies to the European gas market, and they resulted in renegotiations with buyers in its major markets. In