Quarterly Report on European Gas Markets

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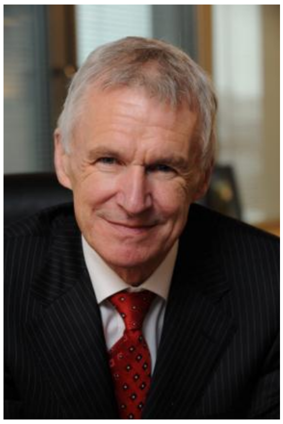

Dear readers,

This Quarterly Report on European Gas Markets includes some interesting gas price developments. Notably, EU hub prices and Long Term Contract (LTC) prices show some divergence: hub gas prices remained relatively stable in the third quarter of 2011, a trend already observed in the previous quarter. In contrast, the prices of LTC oil-indexed gas continued to increase, driven by previous rises in oil product prices.

It is worth noting that not all EU markets have been affected equally by the oil price hikes which have pushed up natural gas prices. EU Member States with well-developed gas hubs have not only had the benefit of greater price stability. LTC prices have also been lower in these markets. This demonstrates the importance of developing hub-trading in the EU.

This report also strongly supports the case for greater gas supply diversification. Countries with more supply diversity not only enjoy greater security. Consumers can also benefit from more competitive and lower prices.

Our 'Focus-on' section offers an insight into power-to-gas. Under the right conditions, this technology could represent an effective means of long-term energy storage and may become attractive to overcome energy surpluses coming from intermittent renewable energy sources.

Philip Lowe

HIGHLIGHTS

- 2011 third quarter EU gas consumption was lower than that for the same period of the three previous years. This followed year on year falls already registered in the two previous quarters of 2011. Altogether, natural gas consumption in the EU in the 9 months to September was 8% below natural gas consumption for the equivalent period of 2010.

- While overall imports of natural gas into the EU continued to grow in the third quarter, Q3 yearly LNG imports fell by 14%, after growing by 20% in the previous quarter. Though fears persisted of diversions to Asia of flexible Qatari LNG originally destined to the EU, in fact the UK (the biggest importer of flexible LNG) continued to experience growing imports of LNG from Qatar, on a yearly basis. This contributed overall to positive growth in yearly rates of imports of LNG to the EU from Qatar, whereas imports of LNG from all the other major suppliers (Nigeria, Algeria and Egypt) actually fell in the third quarter of 2011, relative to the same period in the previous year.

- The overall trend in the third quarter was one of a slight decrease in North Western European hub prices, and a continuation of price increases in LNG prices. This contributed to a further narrowing of the gap between the two price contracts, with LNG prices gradually losing their usual price advantage.

- With regard to Long Term Contract (LTC) gas prices, estimations from Eurostat Comext data suggest that gas imports from Russia were among the highest prices for gas in Q3 2011, while at the opposite end of the spectrum, average LTC prices of gas from Norway to the UK were below UK hub prices over the same period.

- According to estimations, the level and trend of hub prices in markets such as the UK and Belgium, which mostly depend on gas delivered through their hubs, seem to drive the level and trend of LTC gas in such markets. This is also true of the price of LNG gas in such markets. Thus, such markets were benefiting not only from low hub prices in 2011, they also benefited from low LTC prices.

- The average German border price has also continued to be converging towards the German hub prices in the third quarter, as was already evident in recent previous quarters. This suggests that the actual prices now being paid for gas in Germany are being increasingly influenced by spot gas prices, as major importers demand concessions from their suppliers to account for the oil-link/spot gas price divergence.

- According to estimations from Eurostat Comext data, the prices of Russian gas paid in the Baltics and in Central and South Eastern European parts of the EU continue to exceed the average price of German LTC imports of gas in the third quarter of 2011.

NEW FEATURE

- Analysis of occurrences of adverse flow events in hub trading of day-ahead gas contracts.

QUARTERLY REPORT ON EUROPEAN GAS MARKETS

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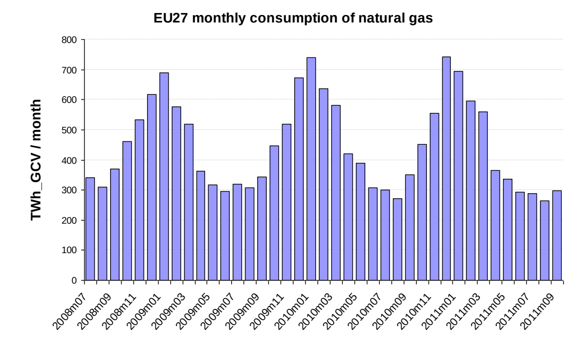
A. Recent developments in the gas markets across Europe

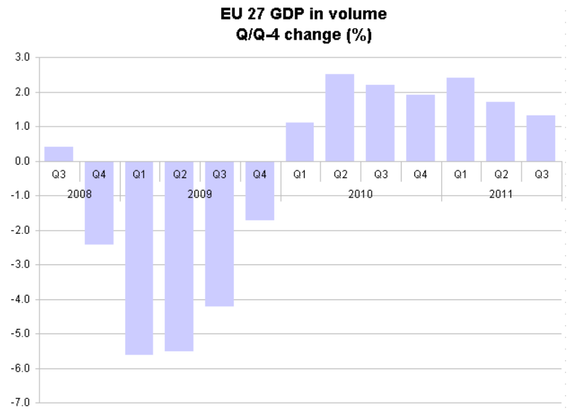
A.1 Gas consumption, production and imports



Source: Eurostat

2011 third quarter EU gas consumption was equivalent to 851 TWh, which was less than gas consumption in the third quarter of the two previous years, and much less than 2008 Q3 gas consumption. This follows year on year falls already registered in the two previous quarters of 2011. Altogether, natural gas consumption in the EU in the 9 months to September was 8% below natural gas consumption for the equivalent period of 2010.

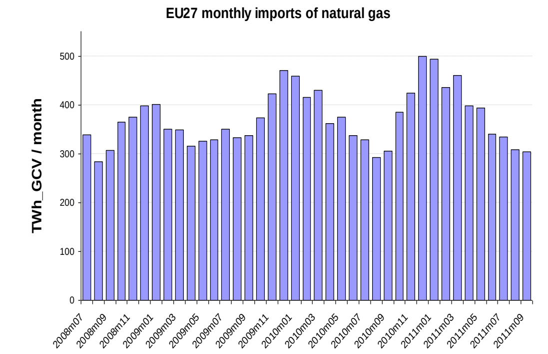
In the third quarter of 2011 the EU economy grew by a modest 0.3% compared to the previous quarter, and by 1.3% on a year-on-year basis, revealing signs of a further slowdown after growth rates of 2.4% and 1.7% recorded in the two previous quarters.



Source : Eurostat.
Selected Principal European Economic Indicators

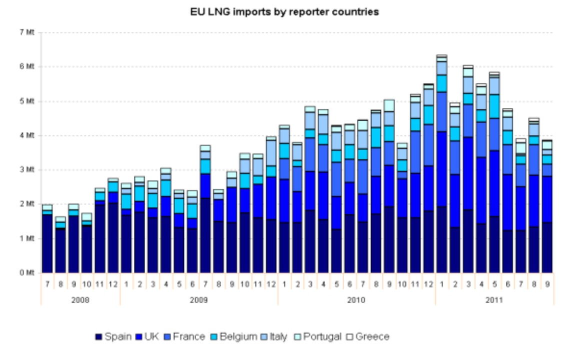
In contrast to consumption, and in line with observed trends in the first two quarters of the year, EU imports of natural gas in the third quarter of 2011 exceeded Q3 2010 levels (growing by 2%, to 947 TWh). In addition, Q3 import levels exceeded consumption for that quarter, as was also the case in the previous quarter, providing extra supplies for gas storage re-injections, and thereby adding to the high levels of gas storage (see storage section) already observed in the second quarter.

Positive growth in total imports of natural gas observed in the third quarter contrasts with falling imports in LNG. According to Eurostat external trade numbers, after growing by 20% year on year in the second quarter, imports of LNG to the EU in the third quarter fell by 14%, relative to import levels recorded in the third quarter of 2010. And compared to the second quarter of 2011, LNG imports to the EU fell by 24% in the third quarter.



Source: Eurosta

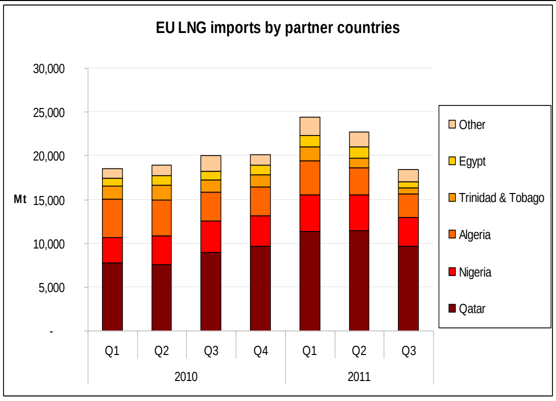
Looking specifically at the UK and Belgium, both dependent on high levels of flexible LNG imports, the evolution of imports in the third quarter varied from the second quarter. To recall, both markets experienced high year on year growth rates in levels of LNG imports in the second quarter (by 67% and 30% respectively).



Source: Eurostat COMEXT
Italian data reported from January 2009.
French data reported from January 2010.

In the third quarter however, while the UK continued to import much higher levels of LNG than the equivalent quarter in 2010 (by 30%), Belgium imported much less (by 45%).

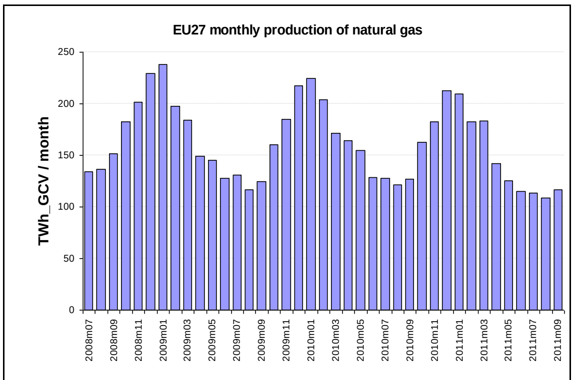
And relative to the previous (Q2) quarter of 2011, both MSs imported much less LNG (by 25% and 9%, respectively). Note however that all other EU importers of LNG, i.e: Spain, Portugal, France, Italy and Greece - which rely much less on flexible contracts of LNG - experienced falling LNG supplies in the third quarter both on a year on year and quarterly growth basis, with the exception of Greece.



Source: Eurostat COMEXT

Examining the origin of imports more closely, it can be reported that imports of LNG from all the major suppliers (Qatar, Nigeria, Algeria and Egypt) fell in the third quarter of 2011, relative to the previous quarter.

Parallel to increasing imports, EU natural gas production continued to fall in Q3 2011, by 10% year on year. A 14% fall was recorded in Q2 of 2011.



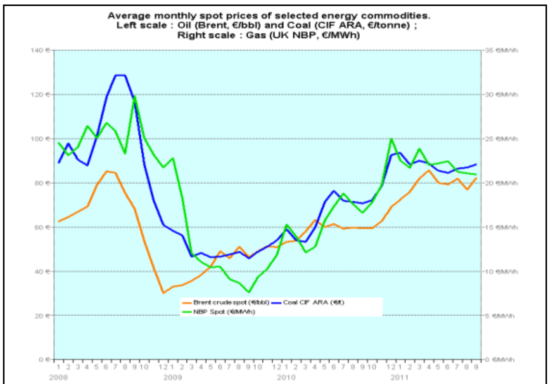
Source: Eurostat.

A.2 Wholesale markets

A.2.1 EU spot gas markets

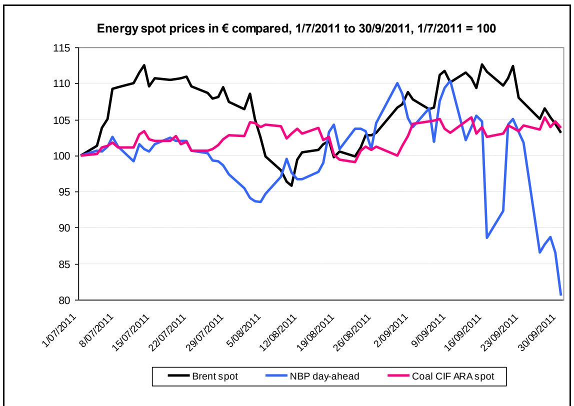
A.2.1.1 Overview

To recall, after the Japanese nuclear outage incident in the first quarter of 2011 (which had only a temporary effect on prices), the trend of energy commodity prices in the second quarter was a downward one, with coal, oil and gas prices falling by more than 5% over the course of the period. Gas prices (as represented in the graph below by the NBP day-ahead), experienced an upward correction in May (due to supply constraints resulting from pipe outages), only to fall back down again for the remainder of the quarter.



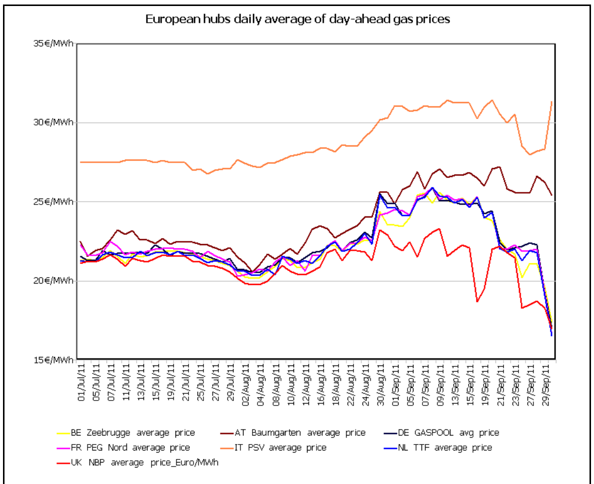
Source : Platts.

In contrast, in the third quarter of 2011, it can be seen in the two graphs below that while the price of the natural gas benchmark fell overall in the third quarter of 2011, the prices of Brent and coal increased slightly. In addition, the evolution of the prices of the three energy commodities over the course of the quarter was far from uniform, as can be clearly observed in the second graph below showing indexed growth between July and September 2011.



Source: Platts.

Plotting the evolution of European hub day-ahead prices, (in the graph below) it can be seen that while NWE (North-West European) hubs evolved in a tight range in July and August, by September both the UK and Austrian hub prices diverged from the rest for most of the month. As usual, the day-ahead price on the Italian PSV far exceeded the average NWE price during the whole quarter.



Source: Platts.

Q3 experienced an initial continuation of the trend observed in Q2, that is a continued, gradual, fall in NWE prices, reaching lows of close to 20€/MWh by the beginning of August, while Italian prices continued to increase, reaching quarterly highs in excess of 30€/MWh by mid-September.

However from the first week of August, prices rose over the remainder of the month resulting from a combination of several pipe maintenace programmes- typical at this time of year - and as news emerged of the upcoming maintenance of Qatari LNG trains, with the fear that it could reduce availability of spare LNG in the spot market.

By the end of September, the NBP had fallen due to the outage of the UK-Belgium interconnector for maintenance for two weeks, preventing spot gas from the UK to be exported to the Continent, and therefore eliminating that demand pressure. The UK's main gas storage facility was also shut for maintenance, preventing spare gas from being put in storage and therefore adding to the bearish pull on UK prices.

At the other end of the price range was Italy's PSV, pressure on prices coming from maintenance work on the Trans-Austrian pipeline supplying Russian gas to Italy through Austria, which reduced imports by about 30% in the second week of September. The Greenstream pipeline, connecting Lybia and Italy, also continued to be out of action.

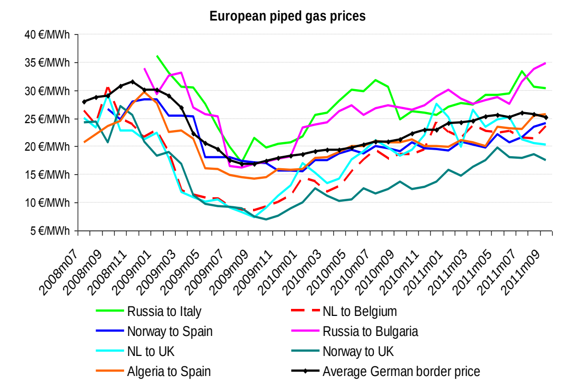
The overall trend in the third quarter was one of a price decrease. Prices across NWE hubs which averaged close to 22€/MWh at the beginning of July, fell to an average level of slightly less than 21€/MWh by the end of September.

A.2.1.2 Gas contracts and pricing mechanisms

Estimated monthly average spot LNG prices in the EU[1] in the third quarter of 2011 traded within a wide price range of between 18.8 and 40.1 €/MWh, and averaged at 22.7 €/MWh (volume-weighted) for the period across the seven countries for which data is available. This represented a continuation of increases in LNG prices in the EU, uninterrupted since mid-2009. The continued rising trend of LNG prices as against one of slightly decreasing hub day-ahead prices meant that the gap between the two, which had already been narrowing in the second quarter, was further reduced.

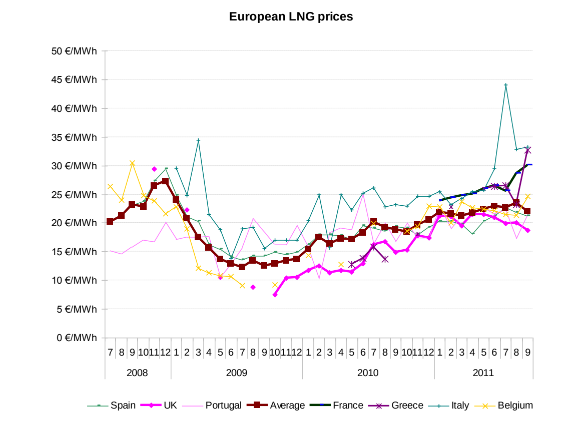
Looking at a selection of Long Term Contract (LTC) oil-indexed border prices for piped gas in Europe, shown in the graph below, reveals an average price of 24.8 €/MWh for the third quarter, from a range of between 17.6 and 33.4 € per MWh. This compares to average prices for the same selection of contracts of 23.7, 22.7 €/MWh and 21.5 €/MWh in the three preceding quarters.

Based on estimations from Eurostat COMEXT data, LTC prices for gas imports from Russia were among the highest prices for gas in Q3 2011, averaging upwards of 30 €/MWh. In contrast, average LTC prices of gas from Norway to the were less than 19 €/MWh over the quarter, representing less even than UK hub prices over the same period.



Source: Eurostat COMEXT.

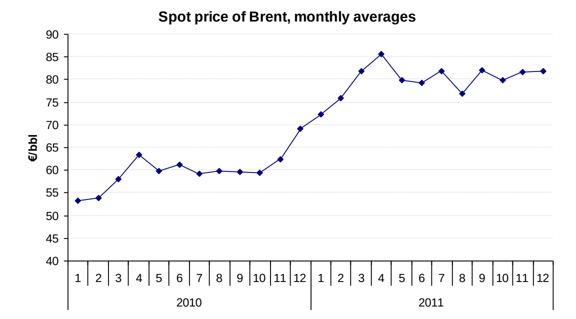
Border prices are estimations of prices of piped gas imports paid at the border, based on information collected by customs agencies, and is deemed to be representative of long-term oil-indexed gas contracts.



Source: Eurostat COMEXT

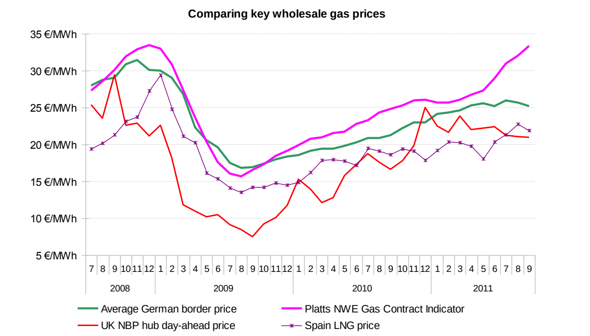
Observing the trend of LTC prices, it can be seen that these have continued to increase in the third quarter of 2011. Given that they are oil price-indexed, with a 6 to 9 month time lag, the relevant oil prices for LTC gas prices in Q3 were therefore oil prices in Q4 of 2010 and Q1 of 2011, when the Brent was very much in an ascendancy phase (see graph below).

[1] Based on Eurostat external trade data.



Source: Platts.

The graph below shows a selection of different wholesale price contracts for natural gas in the EU for a closer comparison.



Sources: Eurostat COMEXT, Platts, German Federal Office of Economics and Export Control (BAFA)

Border prices are estimations of prices of piped gas imports paid at the border, based on information collected by customs agencies, and is deemed to be representative of long-term oil-indexed gas contracts.

The graph shows the UK NBP price for traded gas, which is the European hub benchmark, as well as the price of LNG delivered to Spain, the country being the main importer of LNG in Europe, contributing some two thirds of Spanish gas supply.

The pink line shows the Platts North Western Europe gas contract indicator, which is a theoretical price calculated using a traditional "pure oil-link" formula, while the green line shows the price of actual gas imports at the German border, as published by the German customs agency (BAFA). This price has also traditionally been taken as an indicator showing the price of oil-linked gas into Europe.

Comparing these two lines, it can be seen that the German border price has increasingly been dropping away from the Platts NWE GCI oil-indexed price indicator towards the spot gas price. This was especially true in the third quarter of 2011. This suggests that the actual prices now being paid for gas in Germany are being increasingly influenced by spot gas prices, as major importers demand concessions from their suppliers to account for the oil-link/spot gas price divergence.

In September 2011, the UK NBP average of 21 €/MWh represented 66% of the Platts NWE GCI. This compares to 78% at the end of the second quarter, while in December 2010 the monthly average of the NBP day-ahead price was equivalent to 95% of the NWE Platts GCI for that month.

It can therefore be seen that the divergence between the long term oil-indexed and spot prices for gas continues to grow, and with it the concern of European utilities having to buy gas under long term, oil-indexed contracts, but asked by their own customers to sell at lower spot levels.

A.2.1.3 Regional markets

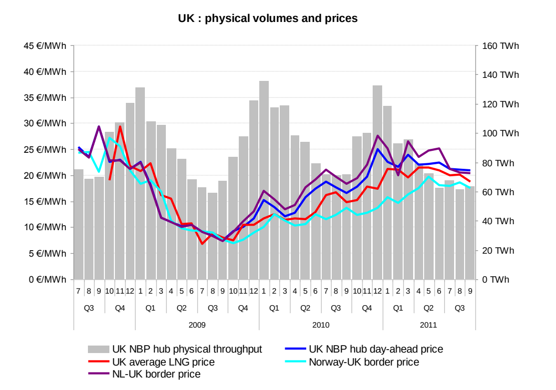
North and South Western Europe

United Kingdom

Physical day-ahead throughputs on the UK's National Balancing Point (NBP) in Q3 2011 fell by 10% relative to the previous quarter, to reach 192 TWh, and also by 10% on a yearly basis, after falling by 21% in Q2 2010. In comparison, gas consumption in the UK fell by 7% relative to the third quarter of 2010, to reach .

Liquidity levels at the UK NBP in the third quarter, as measured by the monthly churn rate[2], was high, averaging just under 16, compared to 14 or less previously in 2011. This was due to the fall in physically delivered volumes (usually low at this time of year), while the total level of UK traded volumes remained relatively constant. Such an increase in the churn rate can be expected for a hub which experiences quite marked seasonal variations in physically delivered volumes along with more constant levels of total energy traded.

The average NBP day-ahead price over the third quarter of 2011 was 21.1 €/MWh, compared to 22.2 €/MWh in Q2 2011 and 22.7 €/MWh in Q1 2011. After having increased every quarter in 2010, the trend of the day-ahead NBP price in 2011 on the basis of three quarters is rather one of slight decrease.



Sources: National Grid (UK), Platts, Eurostat COMEXT.

[2] The churn rate is an indicator of the liquidity of a market/ hub. It represents the ratio between the total volume of trades and the physical volume of gas consumed in the area served by the hub.

A similar trend could be observed for the price of UK deliveries of LNG. It averaged 19.6 €/MWh, compared to 21.3 €/MWh in the second quarter and 20.6 €/MWh over the first quarter. As can be seen in the graph above however, the dip in prices of LNG began later than hub prices. The gap between the UK hub spot and LNG price which was at 2.08 €/MWh in the first quarter of 2011, and which fell to 0.9 €/MWh in the second quarter, stood at 1.48 €/MWh in the third quarter.

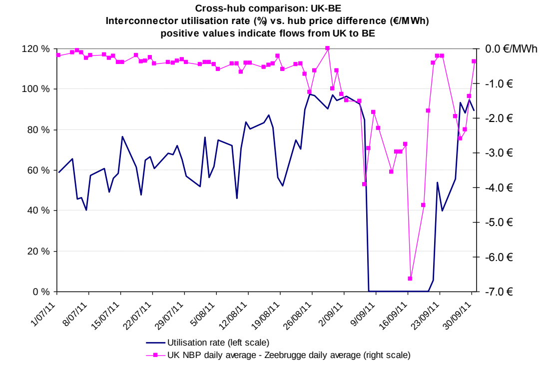
In this issue, estimates of LTC UK border prices for piped gas, based on Eurostat external trade data, have been added for the first time. Thus, prices paid for both Norwegian and Dutch piped gas in the UK appear in the graph above alongside hub and LNG prices. It is interesting to note that these compare rather favourably to other prices, whereas typically recent prices of LTC purchased gas have tended to exceed hub and LNG prices in other parts of the EU. Indeed, it is clear from the graph that the cheapest gas consumed in the UK since the second quarter of 2010 has been imports from Norway.

It is also interesting to note that the price of imports of gas from the Netherlands appears to be very much correlated with the price for gas on the NBP. This is also true of the price of LNG gas, though to a lesser extent.

Turning now to interconnecting flows between the UK and Belgium, it could be observed that natural gas from the cheaper UK hub was being sent to the higher price continent for most of the third quarter of 2011. There was then the usual annual planned two-week shutdown of the interconnector for maintenance during

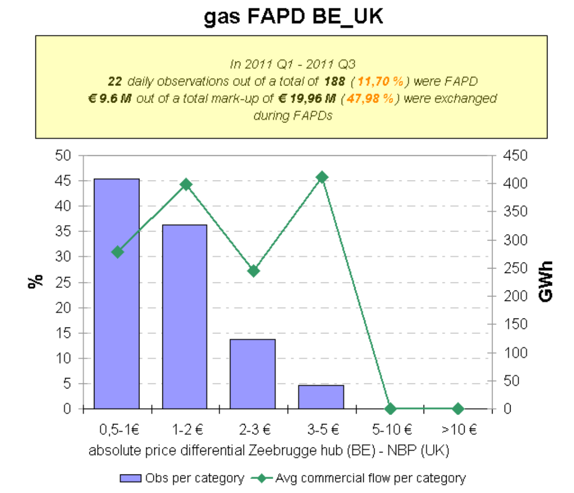
September, the effects of which can be seen in the graph below.

The direction of flows is usual for this time of year, when typically gas flows out from the UK to the continent, while in the cooler quarters such as the first and fourth quarters, it is more usual to see UK bound flows of gas from Belgium, via the interconnector.



Sources: Interconnector, Platts

A closer analysis of occurrences of adverse flows, known as FAPD events[3], also confirms that those events were more frequent during the low gas demand season (Q3 2011).



Sources: Fluxys, National Grid, Platts

After the day ahead market closes, market participants still have the opportunity to level off their positions on the balancing market. That is why a high level of FAPD does not necessarily equate to irrational behaviour. In addition, it should be noted that close-to real time transactions represent only a fractional amount of the total trade on gas contracts.

The FAPD chart provides detailed information on adverse flows. It has two panels:
The first panel estimates the ratio of the number of days with adverse flows to the total number of trading days in a given period. It also estimates the monetary value of energy exchanged under adverse flow conditions (mark-up) compared to the total value of energy exchanged across the border. The mark-up is also referred to as "welfare loss". A colour code informs about the relative size of FAPD events in the observed sample, going from green if less than 10% of traded days in a given period are FAPDs to red if more than 50% of the days are FAPDs.
The second panel gives the split of FAPDs by sub-category of pre-established intervals of price differentials. It represents the average exchanged energy and relative importance of each sub-category on two vertical axes.

[3] By combining daily price and flow data, Flow Against Price Differentials (FAPDs) are designed to give a measure of the consistency of economic decisions of market participants in the context of close to real time operation of natural gas systems.
With the closure of the day-ahead markets (D-1), the price for delivering gas in a given hub on day D is known by market participants. Based on price information for adjacent areas, market participants can establish price differentials. Later in D-1, market participants also nominate commercial schedules for day D.

An event labelled as an FAPD occurs when commercial nominations for cross border capacities are such that gas is set to flow from a higher price area to a lower price area. The FAPD event is defined by the minimum threshold of price difference under which no FAPD is recorded. The minimum threshold for gas is set at 0.5 €/MWh.

As shown in the chart above, during the first 9 months of 2011, there were relatively few FAPD events. For the case of BE and the UK these represented around 10% of total observations. There were very few FAPD events in Q1 2011 and the beginning of Q2 2011 when the gas systems were in their winter configurations. FAPDs became more frequent in Q3.

Most of the FAPD events were concentrated in the low price differential categories (less than 2 €/MWh) and could partly be attributed to exchange rates. With the exception of a single outlier for the 3-5 €/MWh category, the average flows were decreasing as the price differential was widening.

Belgium

2011 second quarter physical gas deliveries at the Belgian Zeebrugge hub (ZEE) were 25% lower than the equivalent quarter of the previous year.

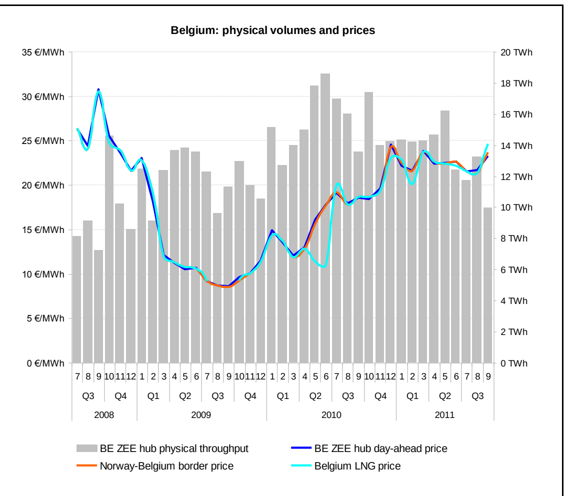
Spot and forward traded volumes at the Belgian hub amounted to 174 TWh in the third quarter of 2011, relative to Belgian consumption of 73 TWh for the same period.

The churn rate on the Belgian hub moved up to attain levels higher than previous quarters (and averaging just under five over the third quarter), for the same reasons as the UK NBP hub, namely a fall in physical throughput (usual for that time of year) while trade volumes stayed relatively constant.

Day-ahead prices on the ZEE hub remained relatively stable in the first two months of the third quarter, after which they increased to exceed 23 €/MWh in the month of September. The average for the quarter was 22.1 €/MWh, compared to 22.5 €/MWh in the two previous quarters.

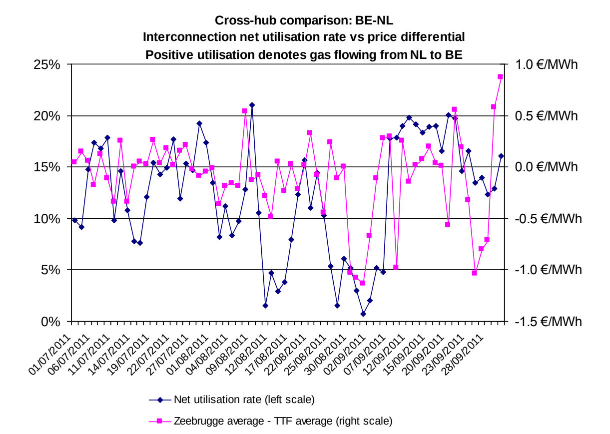
In comparison to Belgian hub day-ahead prices, spot LNG deliveries to Belgium increased very slightly from a Q2 average of 22.4 €/MWh to a Q3 average of 22.5 €/MWh.

Estimates of LTC piped gas from Norway, derived from Eurostat external trade data, have also been added to the analysis of Belgian prices. It shows that there is very little difference between the price of imports from Norway and the ZEE-day ahead price, which is itself also highly correlated with the LNG price.



Sources: Huberator (BE), Platts, Eurostat COMEXT.

The graph below provides a comparison of the evolution of the relationship between gas flows and day-ahead prices on the Belgian and Dutch TTF hubs in the third quarter of 2011.



Sources: ENTSO-G, Fluxys, Platts

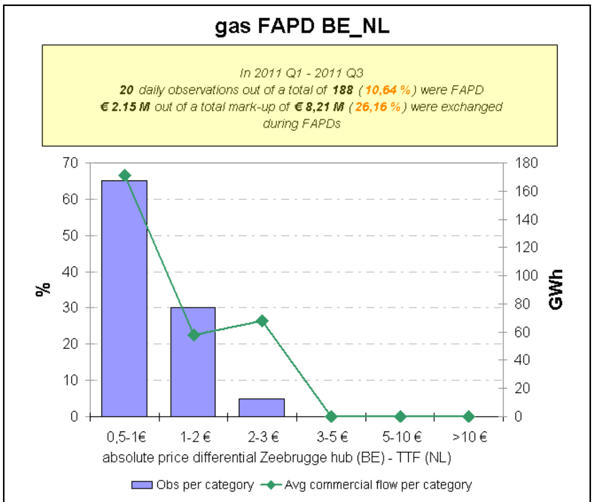
It shows that in the first month of the quarter, there was little difference between Dutch and Belgian prices, and that utilisation oscillated between around 10 and 20%. There were then times when utilisation went down to below 5%, even as the Zeebrugge price hit levels of discounts exceeding 1 €/MWh, relative to the Dutch price. Utilisation rates increased again in September as the UK-BE interconnector was shut for maintenance, meaning that Belgium was more reliant on Dutch gas than is usual. It is interesting to note that the closure of the Interconnector did not have a significant influence on the price differential between the Dutch and Belgian markets, unlike that for the UK-BE markets.

It should also be mentioned that the utilisation rates of interconnector flows of gas between the Netherlands and Belgium are typically quite low, in contrast to interconnector flows of gas between the UK and Belgium. Belgium imports more gas from the UK than from the Netherlands (on average, twice as much in the third quarter of 2011), benefitting in this way from usually cheaper UK gas.

Different levels of flow capacities between the Netherlands and Belgium imply that it was not always possible for gas between the two markets to be flowing from the relatively cheaper area to the more expensive area.

The next chart illustrates the occurrences of adverse flows between Belgium and the Netherlands from January to September 2011, a period containing 188 daily observations on prices and flows.

On average in almost 90% of the cases gas was shipped from the lower to the higher price area.



Sources: Fluxys, Platts

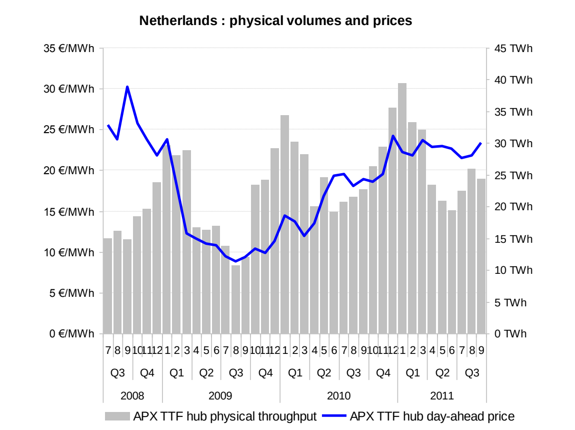
Netherlands

Q3 2011 physical throughputs of gas on the Dutch TTF hub increased by 12% compared to Q3 2010 levels, even as Dutch gas demand continued to decline relative to 2010 (by 11% year on year in Q3, following a 14% decline in Q2).

Traded volumes on the TTF hub in the third quarter of 2011 reached 360 TWh, relative to 221 TWh of natural gas consumed in the Netherlands in the same period.

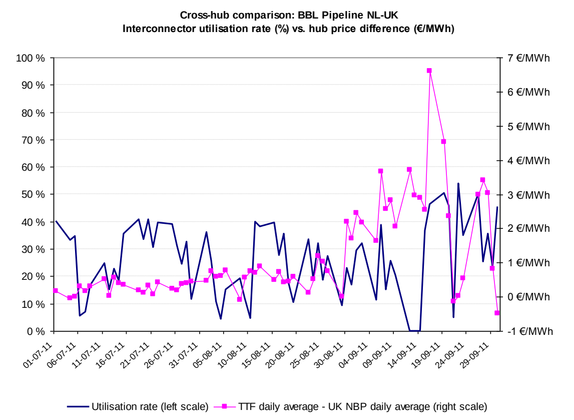
The churn rate on the Dutch hub remained relatively constant in Q3 (averaging just under 5) compared to the previous quarter, though it has moved up relative to Q3 of 2010 (when it averaged 3.9). This is due to a more rapid increase in traded volumes since 2010 than levels of physical deliveries, thereby augmenting liquidity on the hub.

As was the case in the previous quarter, day-ahead prices followed the same trend to that noted for the Belgian hub, registering an average of 22.2 €/MWh compared to a previous quarterly average of 22.8 €/MWh.

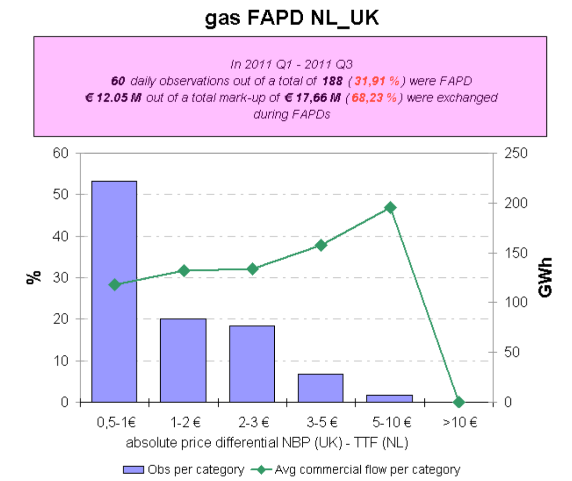


Source: Gas Transport Services, Platts.

Looking at the graph below, it can be seen that the TTF day-ahead traded at a premium to the UK hub throughout most of the third quarter, as was the case in the previous quarter. Yet again, the utilisation rate of the BBL pipeline was very erratic, with significant changes from day to day with no particular rationale vis-à-vis relative changes in prices.



Sources: BBL Company, Platts



Sources: National Grid, Platts

For the case of the Netherlands and UK, FAPD events represented about 30% of the trading days from January to September 2011. The absence of physical reverse flow possibility on the BBL pipeline could explain the relatively high proportion of FAPD events, especially compared to other areas in North Western Europe.

Another possible reason for the high levels of recorded mark-ups[4] could be related to the fact that a large part of the nominated

[4] For the definition of the mark-up, please refer to the preceding footnote.

capacity on the BBL may be attributed to gas deliveries under long term contractual arrangements. The situation on the 16th of September 2011 is an illustration of that possibility: although the TTF price was 6.6 €/MWh higher than the NBP price, market participants nominated 50 GWh in the UK-NL direction and 246 GWh in the NL-UK direction. The net position was one of gas flows from the high price to the low price area.

In addition, it should be noted that the relative share of the mark-up in the total trade on gas contracts is much smaller as the day-ahead trade is just a fraction of the total transacted volume.

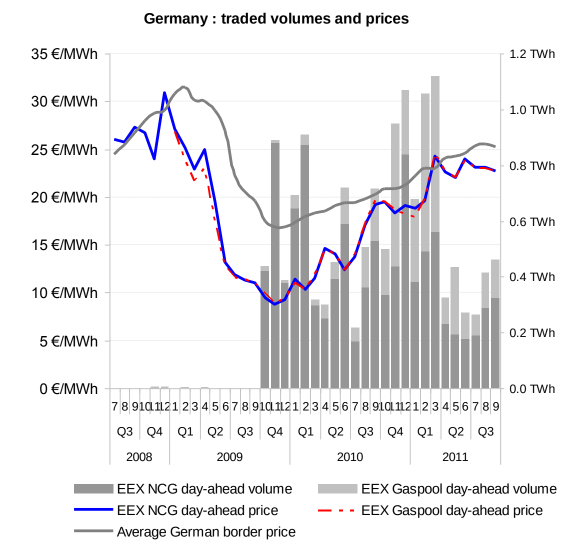
Germany

Combined traded volumes on Germany's NetConnect (NCG)[5] and Gaspool[6] hubs for Q2 2011 amounted to 1.1 TWh, which was slightly higher than what was traded in the previous quarter (1.03 TWh) and much less than a previous quarterly high of 2.85 TWh recorded in Q1 of 2011. German traded volumes remain very modest compared to other hubs in North Western Europe, and also compared to German consumption of natural gas (of 127 TWh in the third quarter of 2011).

The evolution of NCG and Gaspool hub day-ahead prices in the third quarter of 2011 was different to that reported for the Belgian and Dutch hubs, both averaging 22.4 €/MWh in the third quarter, compared to 23 and 22.9 €/MWh registered in the previous quarter.

In addition to hub prices and volumes, the graph below displays the evolution of a number of German border prices, estimated using Eurostat external trade data. It clearly shows that in 2009 and parts of 2010, the average German border price exceeded the German hub prices by a considerable amount. However in the second half of 2010 and in 2011 to date, the gap between the two has been substantially reduced.

This suggests, as already highlighted previously in this report, that the actual prices now being paid for gas in Germany are being increasingly influenced by spot gas prices, as major importers demand concessions from their suppliers to account for the oil-link/spot gas price divergence.



Source: European Energy Exchange, (EEX), Platts, German Federal Office of Economics and Export Control (BAFA), Eurostat COMEXT.

France

Q3 traded volumes traded on France's Powernext Point d'Echange de Gaz (PEG)

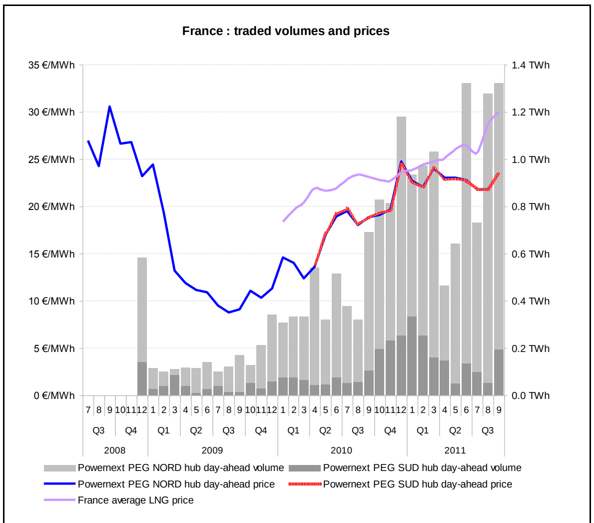
[5] NCG is formerly known as *E.ON Gastransport (EGT)*.

[6] Gaspool is formerly known as BEB. The new market area started on the 1st of October 2009.

Nord and Sud continued to increase strongly on a yearly basis (by 230%), by more even than in the previous quarter (by 179%). Traded volumes in Q3 reached 3.7 TWh, compared to a 2010 Q3 level of 1.5 TWh. Even relative to the previous quarter, growth of traded volumes was impressive (+33%). Though this represents a significant increase, the levels of day-ahead volumes traded on the French hubs remain modest in comparison to the levels traded in Europe's larger hubs such as the NBP, the TTF and the Zeebrugge hubs. 3.7 TWh of traded volumes represents 7% of French natural gas demand in Q3 of 2011 (of 56 TWh).

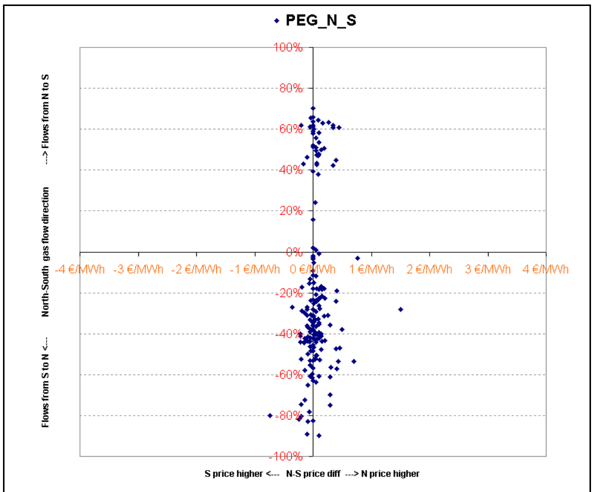
Similar to the Belgian and Dutch hubs, Powernext assessments of PEG Nord and PEG Sud day-ahead prices show stability in the first two months of the third quarter, after which they rose in September. Average prices across both hubs registered levels of 22.3 and 22.4 €/MWh, compared to slightly higher levels of 23 and 22.9 €/MWh in the second quarter.

Relative to hub prices, the price of LNG in France experienced a greater increase since the second quarter (of 9%). At an average price of 28.7 €/MWh for the third quarter, the price of LNG imports paid in France in Q3 continued to exceed that of the UK, Spain, Belgium and Portugal, but was less than that paid by Italy. It is also interesting to highlight that unlike other LNG importing countries such as the UK and Belgium, the price of LNG delivered to France is quite signifcantly higher than the price of piped gas traded on the hubs.



Source: Powernext, Platts, Eurostat COMEXT

The next chart presents the daily price and flow data for the *PEG-Nord* and *PEG-Sud* areas covering the period from January 2011 to September 2011.



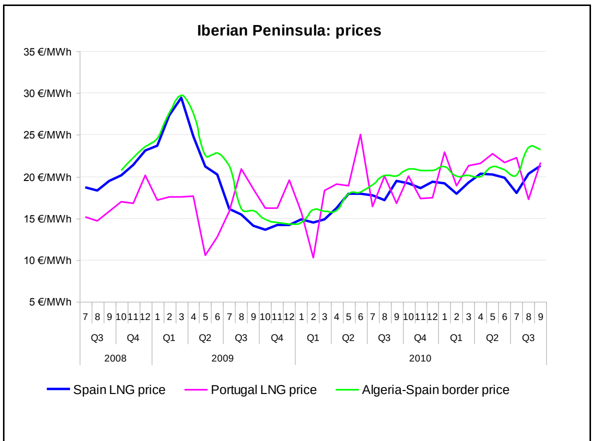
Sources: GRT gaz, ENTSO-G, Platts

The chart above shows that throughout the observed period, the prices in the two French zones traded in a very narrow range of 2 €/MWh. In the majority of cases the flows were directed from South to North. A very low number of FAPD events were recorded.

Iberian Peninsula

Some two thirds of natural gas supplies to Spain and Portugal comes in the form of LNG. The price paid for LNG in the Iberian Peninsula is therefore a key determinant of the cost of imports of natural gas in that region of the EU.

This continues to represent an advantage given the continued relative cheapness of LNG, especially compared to pipe gas delivered under LTC. This being said, Spain also benefits from relatively cheap supplies of LTC piped gas from Algeria.



Sources: Eurostat COMEXT.

Compared to other importers of LNG, both Spain and Portugal continue to pay relatively low prices for their LNG imports. In the third quarter of 2011, the average quarterly price paid for LNG in Spain (of 22.0 €/MWh) and Portugal (20.4 €/MWh) were less than prices paid in Belgium, Italy, France and Greece for LNG in that quarter.

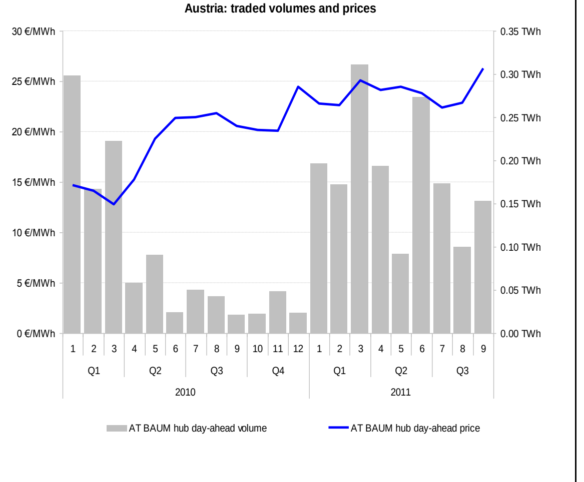
Central and Eastern Europe

Austria

Q3 2011 traded volumes (of 0.43 TWh) at Austria's Baumgarten hub represented an increase of 275% relative to the equivalent quarter of the previous year, after having grown by more than 300% year on year in the previous quarter. Volumes at the Austrian hub therefore continued to increase significantly, even if these still amount to a relatively small proportion of Austrian natural gas consumption (which equalled 13 TWh in Q3 2011).

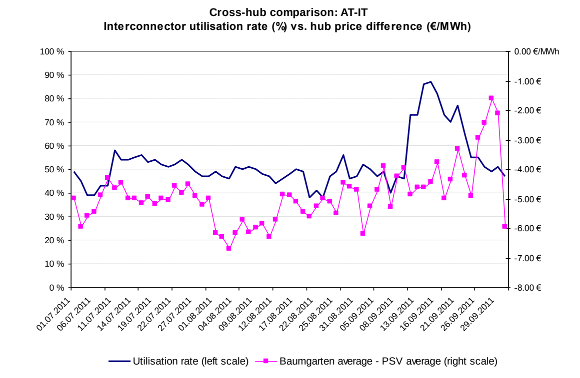
As at a number of other NWE hubs, the day-ahead price in Baumgarten rose during September, after remaining stable in the two preceding months of the quarter. The average Q3 price (of 23.8 €/MWh) was however slightly lower than the previous quarter.

As was already the case in Q2, the Austrian hub price remained higher than North Western European hub prices, having traded at a an average premium of 1.4 €/MWh compared to the Gaspool price.



Sources: CEGH Gas Exchange, Platts, Gas Strategies.

The utilisation rate of the Austria-Italy gas interconnector remained relatively stable for the first two months of the quarter, in line with continued high premium of the Italian PSV hub over the Austrian price. It then increased to reach very high levels during part of September.

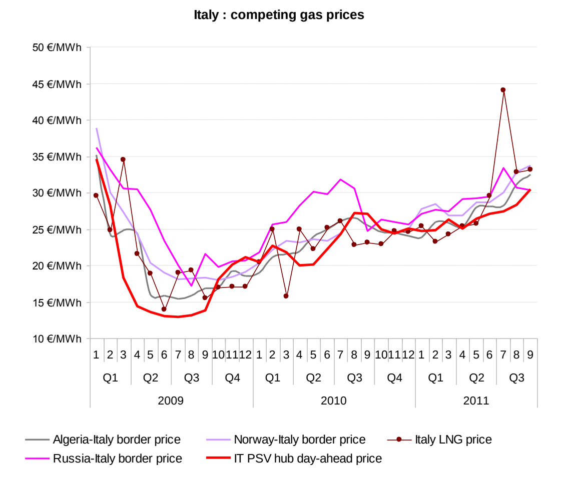


Sources: TAG, Platts

Italy

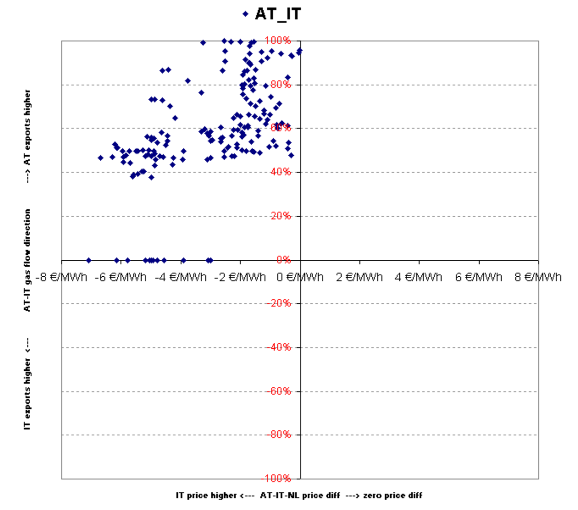
The quarterly average of the price of the day-ahead gas contract at Italy's Punto di Scambio Virtuale (PSV) increased from a level of 26.2 €/MWh in the second quarter to 28.7 €/MWh in the third quarter of 2011.

Pressure on prices occurred especially in the first half of September due to maintenace work on the Trans Austrian pipeline supplying Russian gas to Italy through Austria, which reduced imports by about 30% in the second week of September. The Greenstream pipeline, which brings gas into Italy from Libya (and represents some 10% of Italian imports) also remained closed throughout the third quarter, as was the case in the second quarter.



Sources: Eurostat COMEXT, Platts.

Though the Italian hub price is high relative to other EU hubs, it is still relatively cheaper than the price of LTC gas delivered to the country, according to the data contained in the chart above. The estimated average price of LNG delivered to Italy seemed to experience an anomalous rise in prices in the month of July, after which it traded at levels more in line with LTC contracts. The prices of LTC contracts shown in the graph were relatively similar, with both Norwegian and Russia imports averaging at 36 €/MWh over the third quarter, while Algerian imports averaged 34 €/MWh in the same period. All of those LTC price contracts experienced important increases since the second quarter by between 8% and 15%.

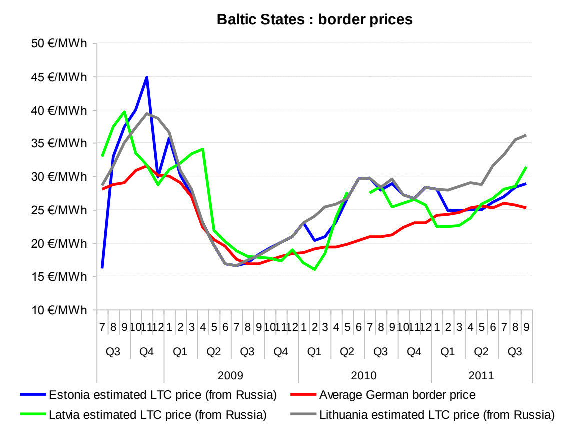


Sources: TAG, ENTSO-G, Platts

The scatter plot with daily prices and flows for the AT-IT areas from January to September 2011 illustrates that the connecting pipeline was used in the normal direction of operation (from Austria to Italy). No reverse flows and no FAPD events were recorded. The Italian price was traded at premium, however it seems difficult to establish a link between utilisation rate and the range of the price difference.

Baltic States

Estimations of LTC prices of Russian gas to the different Baltic States of the EU for the third quarter of 2011 show that after benefiting from falling prices for three successive quarters, Estonia experienced a fairly important increase in price (of 11% to 28.0 €/MWh). In comparison for the same quarter, prices in Lithuania increased by an even more impressive 17% to 35.0 €/MWh) while Latvia paid and average of 29.3 €/MWh for Russian gas in Q3, up 15% since Q2. In comparison, the average monthly German border price paid in Q3 was a much more modest 25.6 €/MWh, revealing to a certain extent of the buying power and diversity of German gas imports.

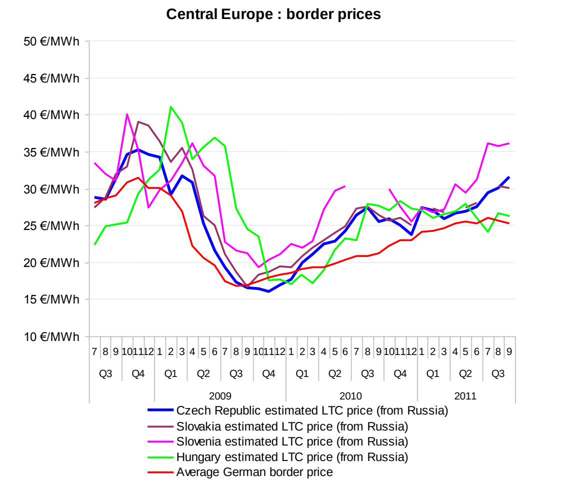


Sources: Eurostat COMEXT, BAFA.

Border prices are estimations of prices of piped gas imports paid at the border, based on information collected by customs agencies, and is deemed to be representative of long-term oil-indexed gas contracts.

Other Central EU Member States

The estimated monthly average LTC price of Russian gas in Central EU Member States in the third quarter of 2011 ranged from 25.5 €/MWh in Hungary to 36 €/MWh in Slovenia, in contrast to a price range in the previous quarter of between 25.7 €/MWh in Hungary to 30.7 €/MWh in Slovenia. As for the Baltics therefore, and with the exception of Hungary, the trend was one of increasing prices for Russian gas in Central EU Member States, by between 8% and 18%.



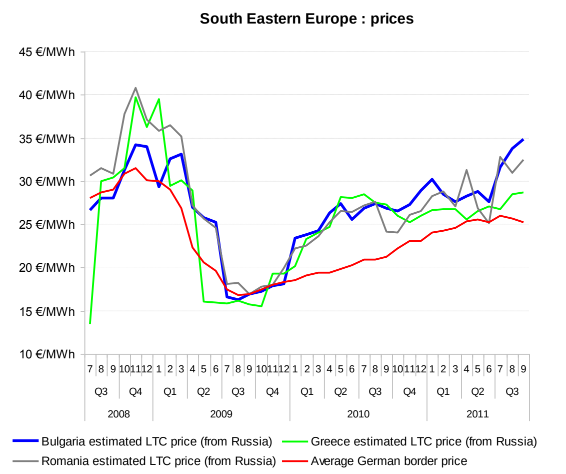
Sources: Eurostat COMEXT, BAFA.

Border prices are estimations of prices of piped gas imports paid at the border, based on information collected by customs agencies, and is deemed to be representative of long-term oil-indexed gas contracts.

Other South-Eastern EU Member States

The average quarterly price of Russian gas in South-Eastern EU Member States in Q3 2011 varied between 28.0 €/MWh in Greece and 33.4 €/MWh in Bulgaria. On a quarterly basis, all three countries (Romania included) experienced increases in prices relative to the previous quarter, after seeing rises between Q1 and Q2.

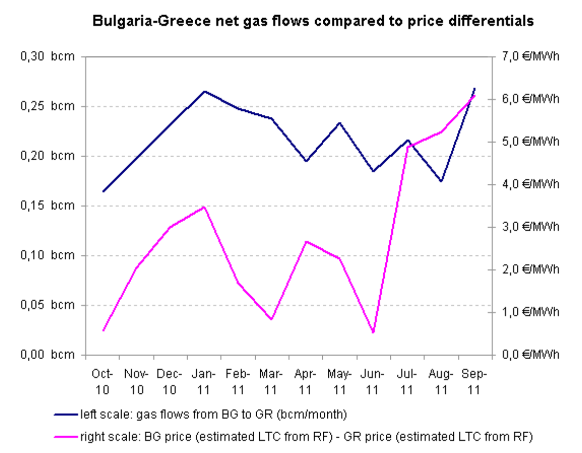
As was the case relative to prices for Russian gas paid in the Baltics and across Central EU markets, the average price of German imports of gas in the third quarter of 2011 continued to be cheap compared to prices paid in South Eastern EU Member States for Russian gas.



Source: Eurostat COMEXT, BAFA.

Border prices are estimations of prices of piped gas imports paid at the border, based on information collected by customs agencies, and is deemed to be representative of long-term oil-indexed gas contracts.

The next chart combines monthly estimations of price and flow data for Greece and Bulgaria covering October 2010 – September 2011.



Sources: Eurostat COMEXT; IEA gas trade flows

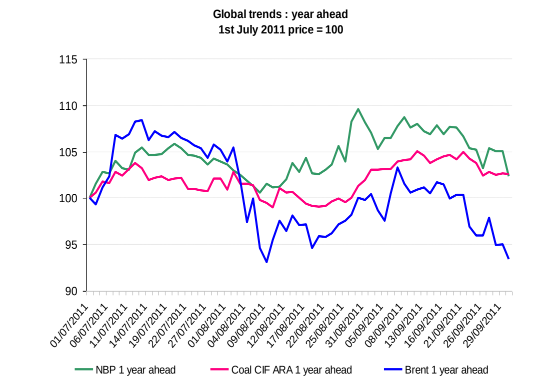
Based on these estimations, it seems that gas was steadily flowing from the high price area (Bulgaria) to the low price area (Greece), an event that would be qualified as an adverse flow in markets with developed hub trade.

In the months of Q3 2011 the premium that Bulgarian consumers had to pay with regards to their Greek counterparts increased significantly to levels above 5 €/MWh.

A.2.2 EU forward gas markets

To recall, after two quarters of continued increases in forward prices of energy commodities – driven initially in Q4 2010 by increasing demand supported by a recovering economy, and then in Q1 2011 by future energy supply uncertainties due to conflicts in the Middle East and Northern Africa – the trend turned bearish in Q2 2011.

As was explained in the last two reports, expectations of rising gas prices came following expectations of probable diversions of flexible LNG from Europe in order to supply Japan following the nuclear outages. Another important factor pushing up gas prices was the uncertainty surrounding nuclear energy in the EU in the aftermath of the incidents in Japan in mid-March. Along with the decision to submit EU nuclear power stations to stress-testing, Germany decided in May 2011 to shut down all of its nuclear capacities by 2022.

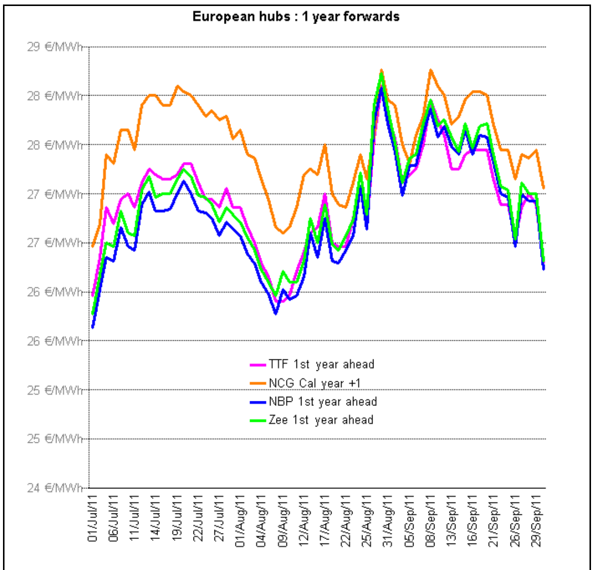


Source: Platts.

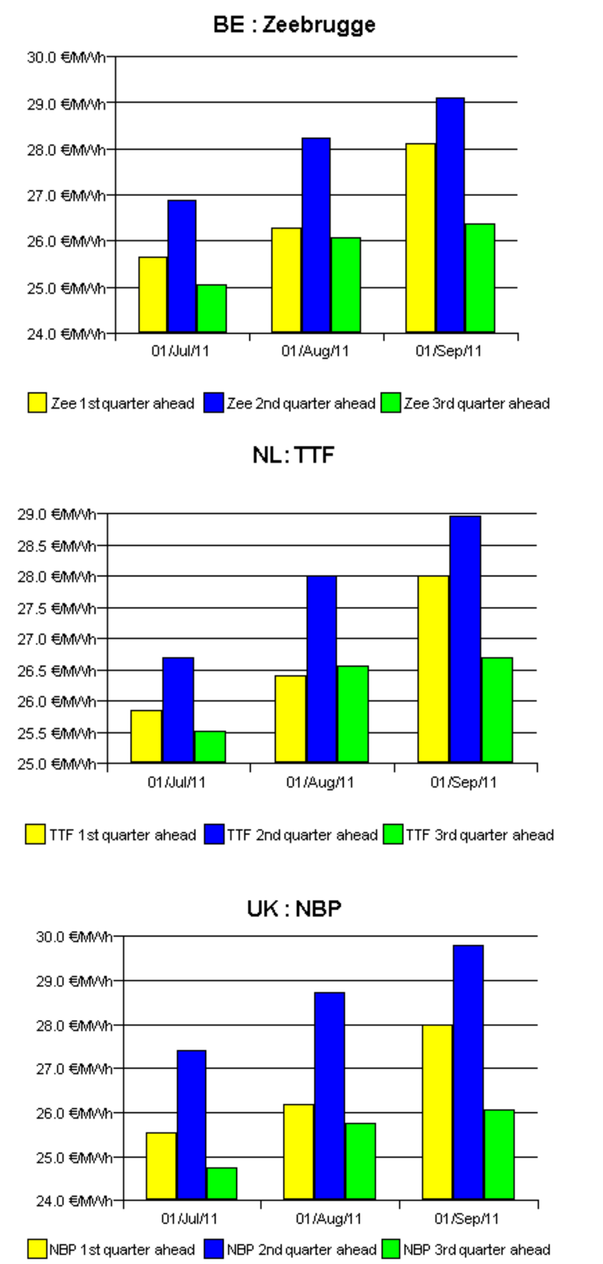
Falling price expectations in the second quarter could be explicable in terms of falling EU gas consumption as well as rising fears of sovereign debt defaults in the eurozone, geopardising the recovery.

While such fears persisted in the third quarter, along with the experience of falling gas demand in the EU, the trend over the third quarter was less clear-cut, with two peaks and throughs clearly visible over the three month period, such that by the end of the quarter one year ahead gas could be bought on EU hubs at levels not significantly different from the beginning of the quarter.

However, the near-forward gas curve continued to be in contango[7], as can be seen if first to third quarter ahead prices are examined for any of the three dates shown in the graphs below. Expectations of increasing near-term forward prices is normal during the third quarter on the basis of climate expectations alone, given that the quarter covers the warmest months of the year.



Source: Platts.



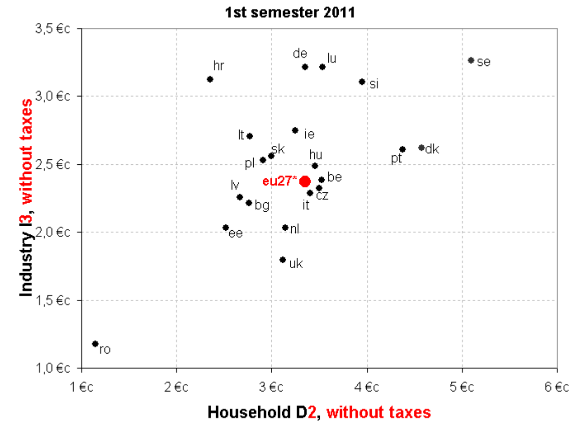
Source: Platts.

[7] The situation of *contango* arises when the closer to maturity contract has a lower price than the contract which is longer to maturity on the forward curve.

A.2 Retail markets

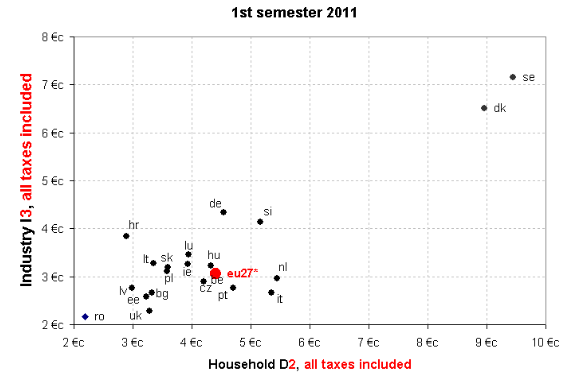
A.2.1 Price levels

The first two charts below show prices of natural gas paid by households and industrial customers in the 1st half of 2011. For both household and industrial customers prices of median level annual consumption bands (corresponding to household consumption band[8] D_2 and industrial consumption band I_3) are illustrated here. The first chart shows gas prices without taxes (net prices) in the EU Member States, Croatia and Turkey. The second chart shows prices including all taxes (gross prices)[9].



Source: Eurostat

Range for annual consumption of :
Household group D2 : [5,56 MWh – 55,6 MWh] ;
Industry group I3 : [2,77 GWh – 27,8 GWh];
Notes; data for Spain, France, Finland, Greece, Turkey and Austria are not available; eu27 is the last available weighted average, as of 2nd semester 2010.*



Source: Eurostat

Range for annual consumption of :
Household group D2 : [5,56 MWh – 55,6 MWh] ;
Industry group I3 : [2,77 GWh – 27,8 GWh];
Notes; data for Spain, France, Finland, Greece, Turkey and Austria are not available; eu27 is the last available weighted average, as of 2nd semester 2010.*

In the first half of 2011 the ratio of the highest and the lowest gross household natural gas price among the EU Member States was 4.3 (for category D_2), while the ratio of the second half of 2010 amounted to 3.9. The ratio was in both cases Sweden/Romania.

In the case of industrial consumers this ratio slightly decreased from 3.3 to 3.1 during the two semesters of 2010. The difference between the cheapest and the most expensive Member State for household consumers amounted to 7,2 €cent/kWh, while in the case of industrial consumers prices varied in a narrower range of 5 €cent/kWh in the first half of 2011.

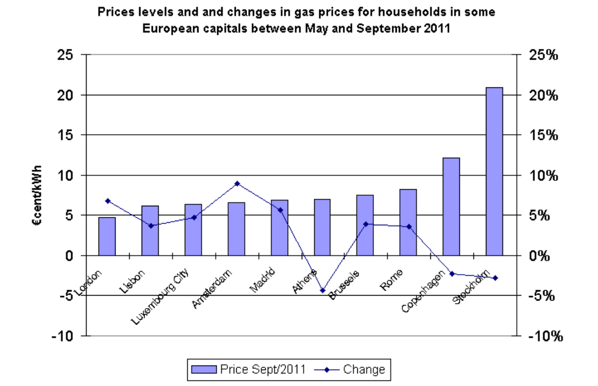
The next chart shows the evolution of all-inclusive retail gas prices paid by households in some European capitals between May 2011 and September 2011. Price rose in the majority of European capitals. The highest increase was in Amsterdam (8.94%), followed by London (6.76%) and Madrid (5.68%).

[8] It should be noted that the indicative Eurostat categories of household and industry consumers are not necessarily representative of the average customer for a given Member State due to different consumption patterns across the EU.

[9] In the case of industrial consumers prices without VAT are presented as gross prices while industrial consumers are subjects to VAT reimbursement and VAT free prices better represent the prices they actually pay.

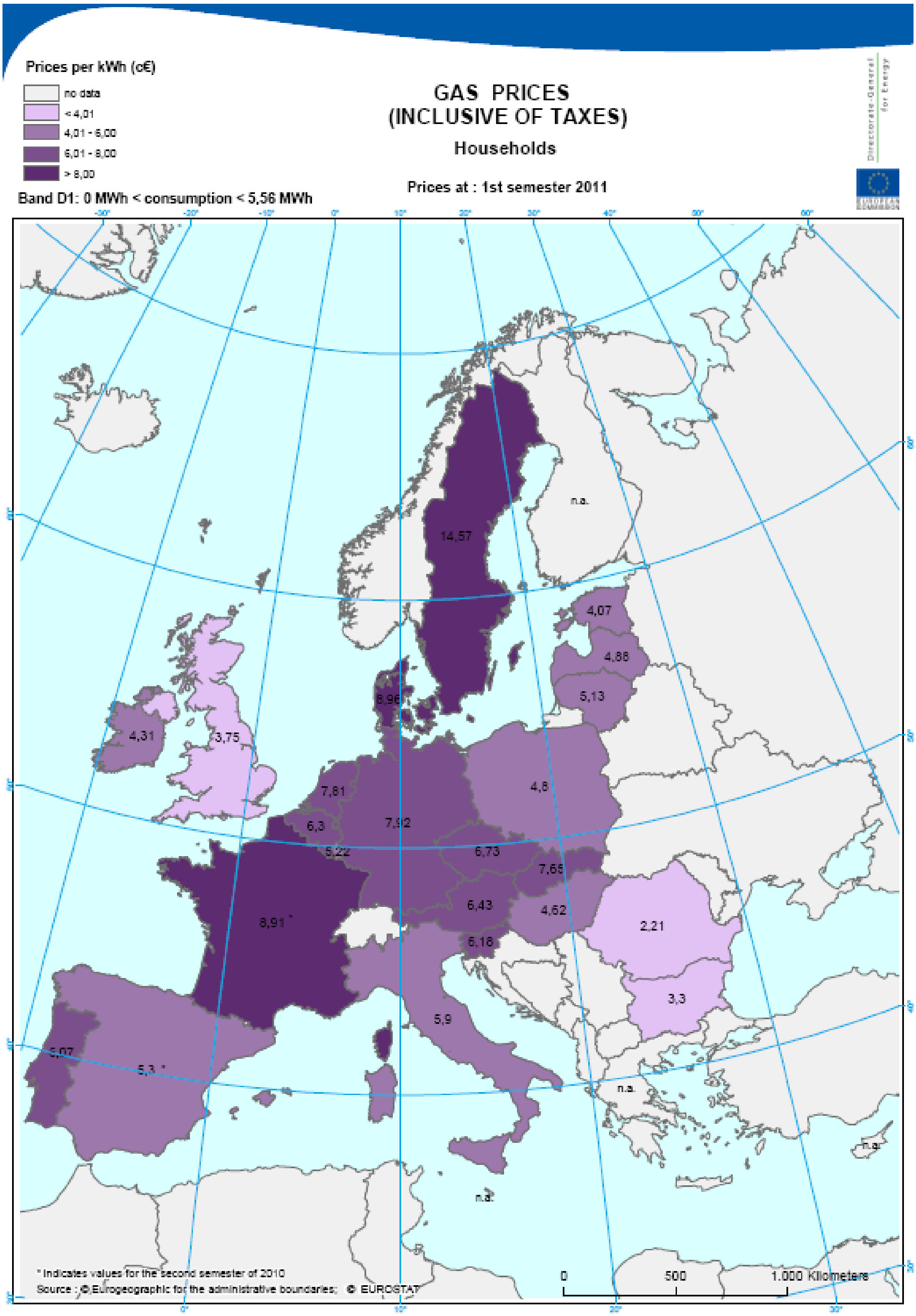
The most significant price decreases were in Athens (-4.4%), Stockholm (-2.8%) and Copenhagen (-2.33%).

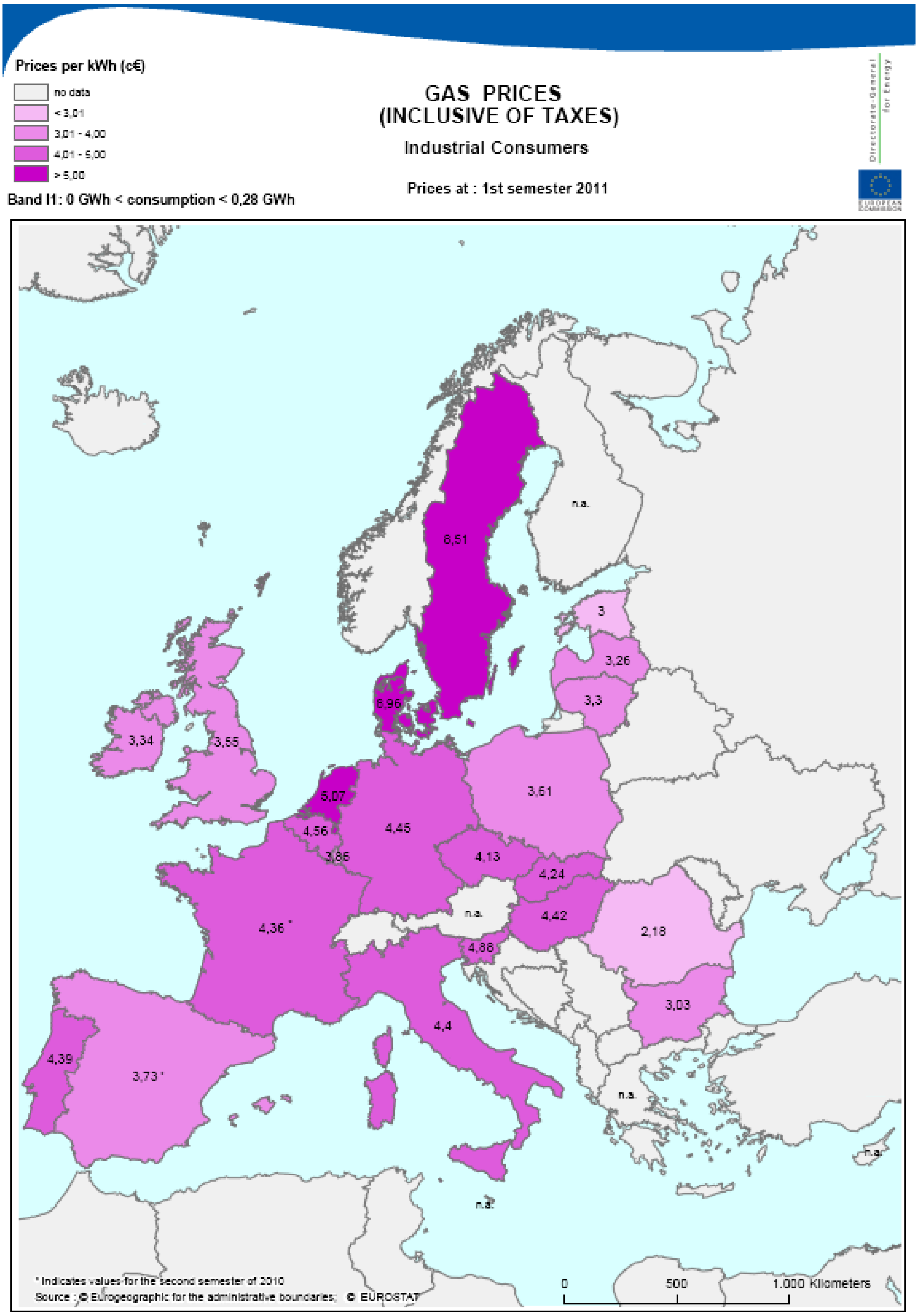
In the next page, two maps illustrate the level of retail prices throughout the EU countries during the first semester of 2011.



Source: HEPI

The HEPI gas price index was developed by the Austrian energy market regulator E-control and VaasaEtt Global Energy Think Tank, providing monthly information about the evolution of the final gas consumer prices in some selected capital cities of EU countries.

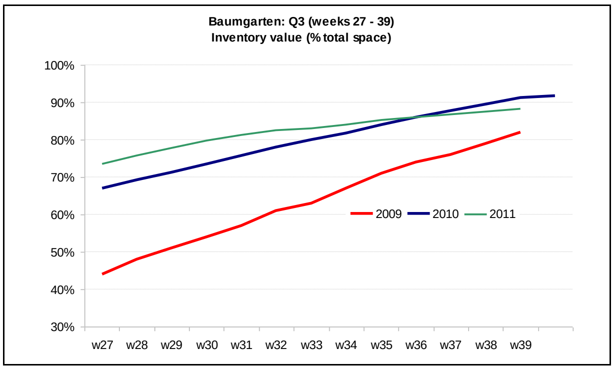

Prices per kWh (c€)
no data
< 4,01
4,01 - 6,00
6,01 - 8,00
> 8,00
Band D1: 0 MWh < consumption < 5,56 MWh
GAS PRICES
(INCLUSIVE OF TAXES)
Households
Prices at : 1st semester 2011
14,57
n.a.
4,07
4,88
5,13
8,96
4,31
3,75
4,8
7,81
6,3
7,92
5,22
6,73
7,65
6,43
4,62
2,21
8,91 *
6,16
3,3
5,9
6,07
5,3 *
n.a.
* Indicates values for the second semester of 2010
Source : © Eurogeographic for the administrative boundaries; © EUROSTAT
0
500
1.000 Kilometers

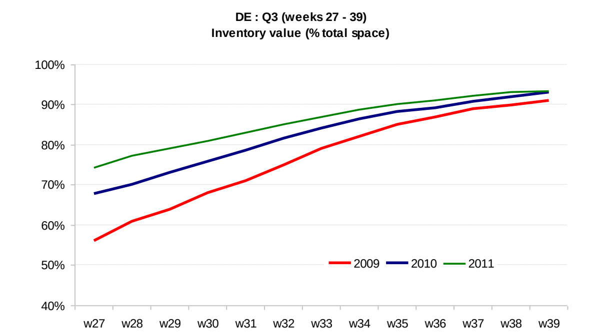

Prices per kWh (c€)
no data
< 3,01
3,01 - 4,00
4,01 - 5,00
> 5,00
Band I1: 0 GWh < consumption < 0,28 GWh
GAS PRICES
(INCLUSIVE OF TAXES)
Industrial Consumers
Prices at : 1st semester 2011
Directorate-General for Energy
n.a.
6,51
3
3,26
3,3
6,96
3,34
3,55
5,07
3,61
4,56
4,45
3,85
4,13
4,24
n.a.
4,42
4,36 *
2,18
4,86
3,03
4,4
4,39
3,73 *
n.a.
n.a.
n.a.
* Indicates values for the second semester of 2010
Source : © Eurogeographic for the administrative boundaries; © EUROSTAT
0
500
1.000 Kilometers

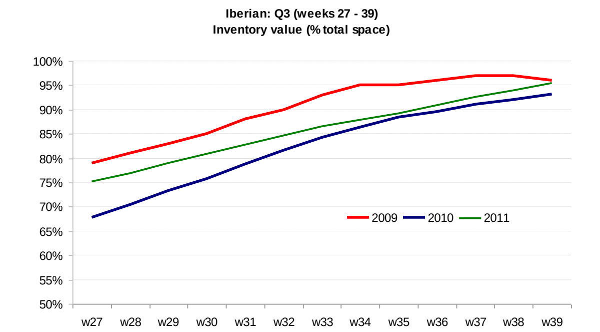
B. Storage

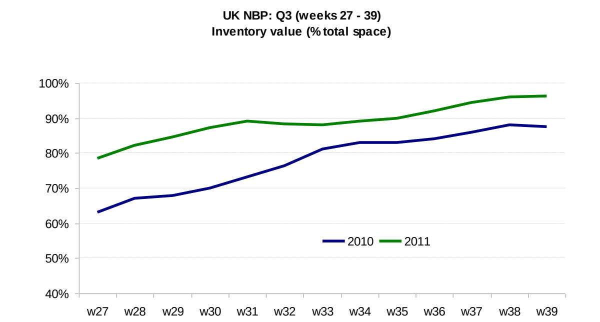
Mild weather across the EU in the first and second quarters of 2011 contributed to relatively low levels of demand for natural gas over the course of that period. This allowed for reinjection of gas into storages while withdrawals were limited, such that storage levels by the start of the third quarter were generally high for that time of year across EU hubs. The story is then the same as for the second quarter: the third quarter would likely have witnessed opportunistic reinjection of gas into storages which the contango situation of day-ahead and near term hub prices incentivised.

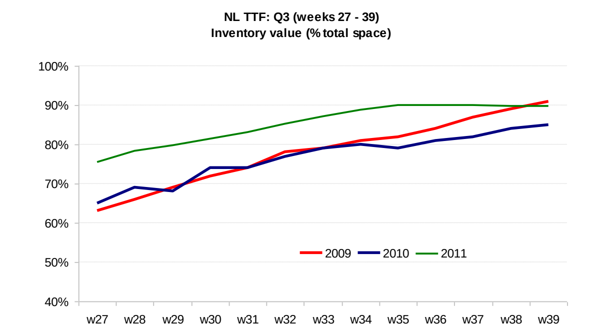
Storage levels continued to rise during the first two months of the third quarter as the mild weather remained. By September however, increasing storage withdrawals to meet gradually increasing demand for natural gas meant that storage levels grew less quickly, and even flattened at certain hubs.

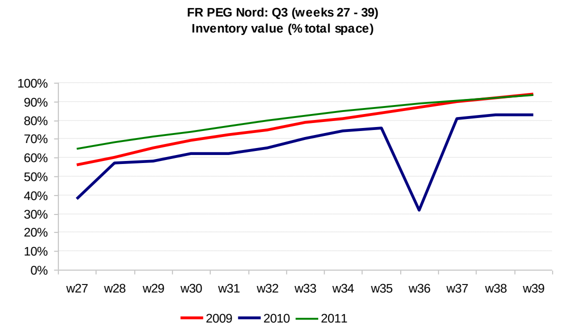


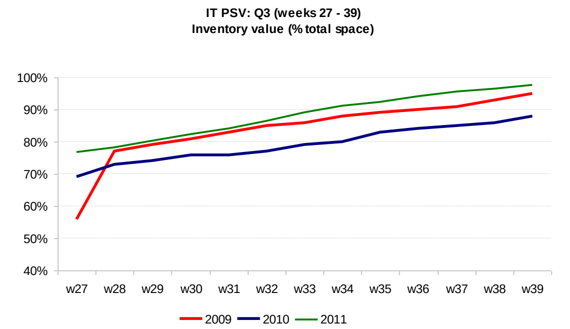


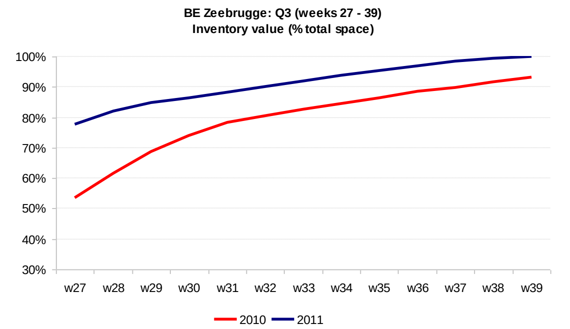








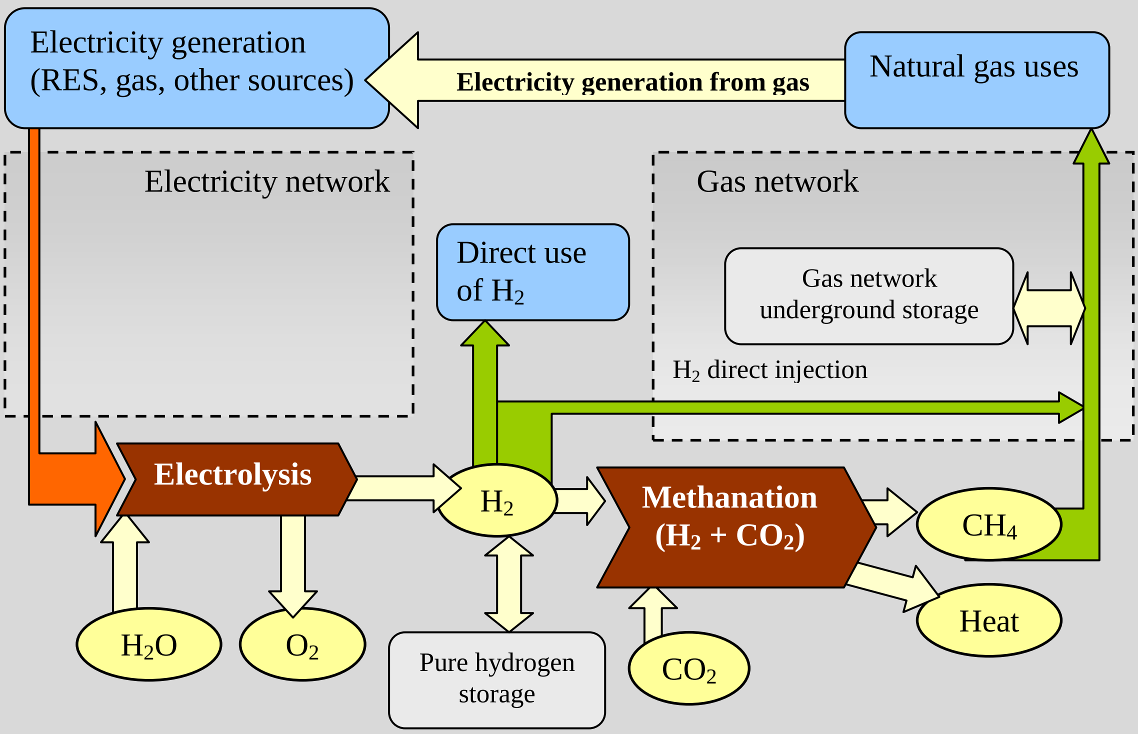




Source: Gas Infrastructure Europe

C. Focus on Power-to-Gas and large scale storage of electricity

Power-to-gas is a fuel technology which produces chemical energy carriers from electrical energy. According to the current state of the art, hydrogen (H_2) is always produced in the first step from water and electricity via electrolysis. H_2 can then in an optional second step be further processed together with carbon dioxide (CO_2) to generate methane (CH_4) or other hydrocarbons. Methane obtained through such a process is often referred to as Substitute Natural Gas (SNG).



The non-economic storability of electricity is one of the reasons for its high price volatility, which in conjunction with a less flexible generation park can even result in negative prices in cases of extreme over-supply. Storage is one way of reducing such intermittency. Power-to-gas, together with other storage technologies, has the potential to be a a solution to the intermittency of generation of renewable energy sources (RES) by providing a way to store excess electricity supply as hydrogen or methane. It would constitute a type of "chemical" storage, which has the significant advantage of being a long-term storage option. This would enable the use of stored energy to address not only short-term peaks but also seasonal fluctuations and prolonged periods of low or no wind.

In this context, when renewable energy generation exceeds demand, surplus electricity could be put to use to produce hydrogen. If not consumed on the industrial site, hydrogen needs to be transported (trough dedicated pipeline or tank trucks) or stored. If it is not stored in pure form, hydrogen can be:

1. directly injected into the gas network to obtain a blend of natural gas and H_2. However, the amount of H_2 which can be added is limited and not clearly defined. It strongly depends on the gas consumers already have installed in the system and their capabilities to cope with H_2. Current figures vary quite a lot from a few percent to 10% and beyond.

2. transformed into CH_4 and then injected in the network as a natural gas substitute. For this option a CO_2-source is needed, which can be a fossil power plant or a biomass plant.

Both options allow to benefit from the already existing gas storage facilities in the gas network. In the foreseeable future, as the demand for gas is deemed to decline due to energy efficiency and gradual adoption of RES, additional spare capacity in the gas network would increase, making the business case for power-to-gas more feasible. With respect to the first option, it is for example already viable in Germany, where it is permitted to add up to 5% hydrogen to natural gas[10].

If in the future there will be a business case for Power-to-gas as a means of methane production, SNG produced from such a technology will have to compete with established suppliers in bringing natural gas to final consumers. Reducing costs along the whole value chain remains a challenge for the economic operation of the process. For example, the introduction of economic and flexible electrolysers could accommodate power input from intermittent sources with variable operating hours. However, new electrolysers[11] also entail higher costs.

Different research and development initiatives are aiming to demonstrate the business case of the power-to-gas technology. Such a business case should also account for the commercial availability of CO_2 through carbon capture and storage (CCS) which has not reached the market yet. Furthermore, the use of H_2 and CO_2 to produce SNG will have also to outcompete the market for direct hydrogen combustion.

The European Commission is participating in the Fuel Cells and Hydrogen Joint Undertaking (FCH JU)[12], a public private partnership, which

[10] According to Code of Practice - DVGW G 262.
[11] Newly developed PEM electrolysers can accommodate much more flexible workloads with respect to Alkaline electrolysers. The costs of PEM technology are however significantly higher.
[12] http://www.fch-ju.eu/page/who-we-are

supports, among others[13], the NEXPEL[14] project to further develop and demonstrate next generation proton exchange membrane (PEM) electrolyser technology suitable for highly efficient hydrogen production from renewable energy sources.

With respect to hydrogen injection into the gas grid, the EU funded with €17.3 million the NATHURALHY project, the objective of which was to study the addition of hydrogen in natural gas networks. The project found that the transmission, distribution and use of natural gas are not compromised if up to 20% of hydrogen is added to natural gas. The maximum percentage in the specific geographic areas depends on the local gas distribution conditions.

[13] See list available at http://www.fch-ju.eu/Projects%20by%20application%20area/Hydrogen%20production%20and%20storage

[14] Further information can be found on the project website www.nexpel.eu

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