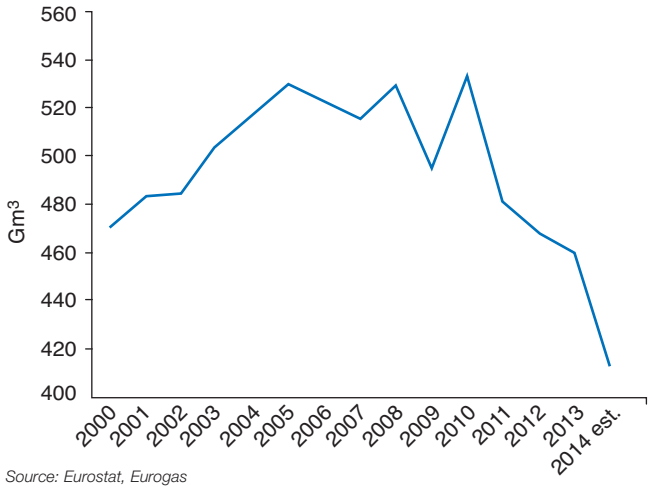
Gas and Coal Competition in the EU Power Sector[1]

Never have the fossil-fueled thermal European power sector, and natural gas in this sector, seen such a crisis. EON's recent announcement of its future withdrawal from fossil-fueled thermal power generation illustrates the difficulties faced by producers in Germany. But the whole European power sector is in deep crisis, and natural gas is its first victim. Faced with a flat electricity demand in Europe, the rapid development of renewable energies, and competition from coal, natural gas is losing market share and its consumption is in decline. In 2013, total gas consumption in the European Union (EU) fell for the third year running. Projections for 2014 are no better, consumption is forecast to decline by approximately 10% (Fig. 1), greatly affected by the mild winter of 2013/2014 compared with the previous one which was particularly cold over a long period. The milder temperatures impact the need for heating, therefore consumption in the residential/services sectors and also the demand for electricity. The International Energy Agency (IEA) is now predicting that European consumption will not get back to its 2010 level until 2030[2].

Fig. 1 – EU natural gas consumption (2000-2014)



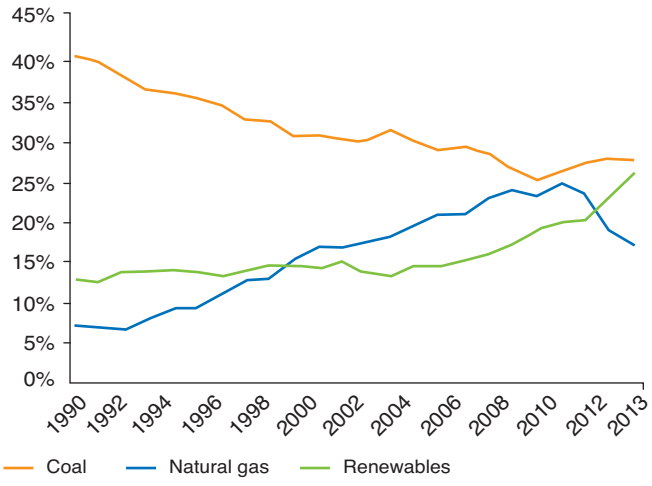
Source: Eurostat, Eurogas

The European paradox: falling gas consumption and rising coal consumption

Natural gas offers many advantages over coal. Combined cycle gas turbine (CCGT) power plants have higher thermal efficiency and emit half as much CO_2 as coal-fired power plants. They are quicker to build, attract less local opposition and their capital cost is lower. Gas power plants also offer greater flexibility than coal-fired plants in terms of adapting their production level to the increased needs for variability of the electricity system, associated with the increase in the use of intermittent sources of production (wind and photovoltaic).

However, despite these many advantages, the share of gas in European power generation is falling. After reaching a maximum of around 25% in 2010, it was only 19% in 2012 and fell to 17% in 2013 (Fig. 2). The contribution of coal, which had been falling since 1990, has on the contrary risen since 2010 and reached almost 28% in 2012. It changed course however in 2013. Faced with the rise in the use of renewable energies (26% in 2013), the share of fossil-fueled thermal power is falling.

Fig. 2 – Contribution of natural gas, coal and renewable energies to the European electricity mix (1990-2013)



Source: Eurostat, BP, 2013: provisional figures

(1) This memo summarizes the main conclusions of the report published by Cedigaz in June 2014: Gas and Coal Competition in the EU Power Sector, June 2014 (http://www.cedigaz.org/products/coal-gas/coal-gas.aspx)

(2) New Energy Policies scenario, International Energy Agency (IEA), World Energy Outlook 2014, IEA/OECD, Paris, November 2014

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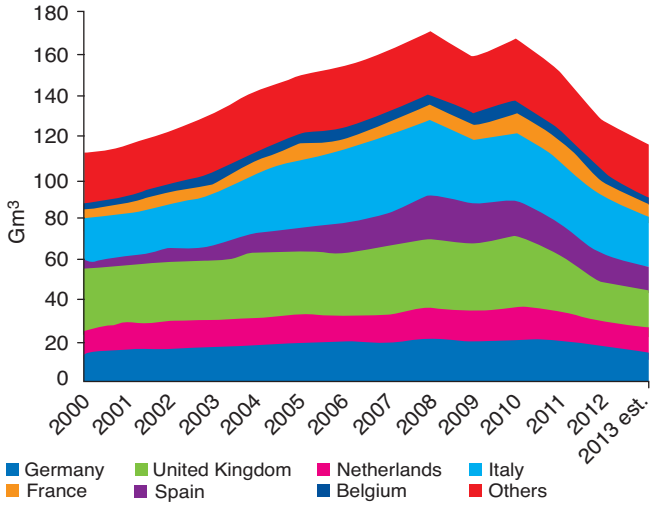
Between 2010 and 2013, the demand for gas by EU power producers fell by 51 Gm^3, *i.e.* a third of its historic level (Fig. 3). This represents a reduction equivalent to the whole of the French gas market. Conversely, the demand for coal in the sector increased by 10% between 2010 and 2012. However it fell by 5% in 2013. These developments have put an end to the downward trend in the CO_2 emissions of the power sector in some key countries, despite the rapid rise in the use of renewable energies. The results for the first six months of 2014 indicate a drastic decline in deliveries of gas to power plants, including, for example, a fall of 70% for deliveries in France.

Fig. 3 – Demand for natural gas in EU power sector



Source: Eurostat, 2013 estimate

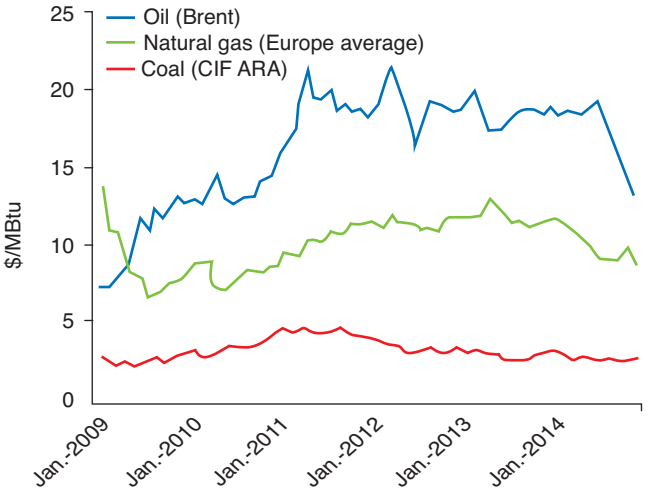
Despite the fall in natural gas prices, coal is still more competitive

The relationship between coal, gas and CO_2 prices is a determining factor of gas and coal switching in the power sector. Since 2010, the relative changes in gas and coal prices have led to a loss of competitiveness for gas, reinforced by the collapse of CO_2 prices.

The price of coal has dropped sharply. In the United States, shale gas is providing fierce competition for coal in the country's electricity mix. Between 2008 and 2013, the share of coal in the US electricity mix fell from 48% to 39% (despite a recovery in the demand for coal in 2013). Faced with the shrinkage of the domestic market — US demand fell by 20% between 2008 and 2013 —, American mining companies turned to outside markets, and particularly Europe, since the main ports for coal export are on the east coast. The inflow of US coal, on an international market that is already well supplied, has created a supply surplus and led to a sharp drop in prices. The price of imported coal in Europe fell by 32% between August 2011 and December 2013. The decline continued in 2014; prices have fallen by 11% since the start of the year and are $74/t (equivalent to $2.7/MBtu) at the end of November 2014. Although US exports are decreasing in response to the fall in prices, the international market is still in surplus following the reduction of imports by China, the world's leading importer of coal. As a reaction to the low prices, mining companies in the main exporting countries have begun to close their more costly mines, but market equilibrium is not expected to be restored before 2016.

Conversely, the average price of imported gas in Europe, still closely related to oil product prices, increased by 42% between 2010 and 2013, in line with oil prices. This rise explains why gas has lost its competitiveness compared with coal. European prices have begun to fall since the start of 2014, as a result of low demand and surplus supply. This decline increased recently with the fall in oil prices. The average price of imported gas in Europe stands at less than $9/MBtu in November 2014, a fall of 23% since the beginning of the year. Despite the fact that this fall is more pronounced than that of coal prices, coal still has the competitive advantage: it is still a third of the price of natural gas on an energy equivalent basis (Fig. 4).

Fig. 4 – Comparative energy prices in Europe



Source: World Bank

The decline in the CO_2 price per ton since July 2011 has reinforced the competitive advantage of coal. While the EU CO_2 allowances trading system had been implemented to send out a strong signal in favour of investments in low carbon technologies, the rapid development of renewable energies and the fall in the demand for electricity following the 2009 crisis have created a huge surplus of CO_2

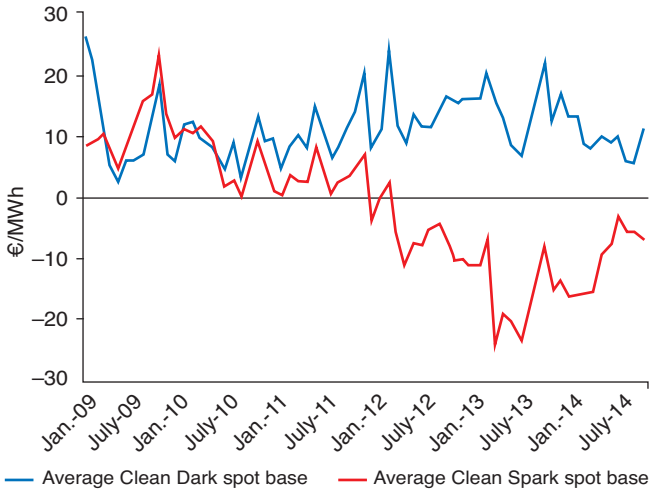
allowances and caused carbon prices to fall to such an extent that the system no longer has any significant role to play. The CO_2 price per ton fell on average from €14.3/t in 2010 to €4.5/t in 2013. With the adoption in 2014 of short term measures (backloading) and a proposal of structural reforms, the European Commission hopes to correct the system's present faults and promote an effective carbon market, sending out an appropriate price signal for future investments in the power sector and making it possible to achieve the target of a 40% reduction in CO_2 emissions by 2030. However, while CO_2 prices have ranged between €5/t and €6/t since the beginning of 2014, a level of €30/t would be needed to promote coal-to-gas switching at the prices recorded in November 2014, a level that is neither achievable, nor desirable, in the short term. A price of €50/t was required at the price levels recorded in January 2014.

Renewable energies are pushing natural gas out of the merit order

In addition to its loss of competitiveness, natural gas is also suffering due to the rapid deployment of renewable energies (wind and photovoltaic). Power generation on the interconnected grid takes place in order of increasing variable costs, applying the logic known as the merit order. For a given fleet, the power generated is first supplied by power plants with the lowest marginal — or variable — cost (run of river hydropower plants and nuclear power plants), then by coal or natural gas power plants, and during peak periods by combustion turbines which therefore only run for a few hours per year and are correspondingly costly. Renewable energies generally have the benefit of guaranteed purchasing prices (feed-in tariffs, or FIT). In addition, their production gets priority dispatch into the power grid. The effect of this mechanism is to push out energies with the highest variable costs, and natural gas in particular, which are therefore only used for a few hours per year, meaning that they are no longer profitable. In Spain, for example, the average CCGT operating rate, historically over 50%, plummeted to 11% in 2013. In Germany, this rate has fallen to 21%. The low use of gas-fired power plants means that the operators can no longer make a profit on their assets. This loss of profitability is accentuated by the drop in electricity wholesale prices. The rapid increase in renewable energies, which have little or no marginal costs, means that the electricity price is more often set by the energy sources with the lowest marginal cost, preventing gas power plants from recovering their fixed costs, and even in some cases their operating costs (the missing money problem).

The loss of profitability of power plants has been particularly marked for operators of gas power plants, which are also faced with competition from coal. The clean spark spread (used to measure the profitability of gas power plants, representing the difference between the market power price and the variable cost of generation, including CO_2) has been negative since 2012. Conversely, thanks to the drop in coal prices and the collapse in CO_2 prices, the clean dark spread (used to measure the profitability of coal power plants) has remained positive (Fig. 5).

Fig. 5 – Clean dark spread and clean spark spread in Germany (2009-2014)



Source: Tendances Carbone CDC Climat Recherche, Thomson Reuters

However, since wind power and photovoltaic power are intermittent, back-up power plants are required. These are often power plants operating on natural gas. Power generation also needs to be adapted to the variability of renewable energies. Here again, it is usually flexible gas power plants that allow such adaptation. But, although they are necessary for rapid deployment of renewable energies, the present system does not allow them to be profitable and is leading to massive capacity closures.

Massive capacity closures: 115-120 GW of gas and coal capacity

Faced with this unfavourable situation, gas plant operators have begun to mothball or close their loss-making plants. At the end of 2013, gas power plants that had been mothballed, closed or were likely to close represented a power capacity of 24.7 GW, or 14% of the installed gas capacity in the EU, mainly in north west Europe. The first plant closures involved older power plants, but worsening market conditions have led to operators mothballing new power plants, even though they offer very high thermal efficiency, in the order of 58 to 60%. If all the gas plants threatened with closure are actually closed, this will lead to a reduction of installed capacity of approximately 50 GW by 2015-2016, or 28%

of present capacity, while at the same time this capacity is needed to ensure power supply security.

While coal-fired power plants have been relatively spared up until now, thanks to the low price of coal and CO_2, the expansion of renewable energies is also beginning to bite in the coal sector and the reduction in electricity wholesale prices is also eroding the profitability of coal plants. In 2013, the European demand for coal in the power sector fell by approximately 5%. The decline continued in the first months of 2014. This trend is reinforced by EU legislation on air quality. The impact of the Large Combustion Plant Directive (LCPD), which limits emissions of local pollutants (emissions of sulphur dioxide, SO_2, nitrogen oxide, NOx, and fine particles), is already being felt in the EU's ageing fleet of coal-fired power plants: 15.8 GW of capacity will be closed by the end of 2015 at the latest, mainly in the United Kingdom and France (most plants are already closed). The Industrial Emissions Directive (IED), due to succeed the LCPD directive from 1st January 2016, reduces the limits for emissions of SO_2, NOx and fine particles. For the oldest coal-fired power plants (40% of the fleet is over 40 years old), there is no financial incentive to invest in depollution installations and approximately 50 to 55 GW of capacities may close by 2020/2023 at the latest. In total, the installed capacity of coal power plants will be reduced by approximately 65 to 70 GW, due to the combined effect of the two directives, representing a third of present capacity.

In total, a capacity of 115 to 120 GW could close in the coming years, or a third of the EU's gas and coal capacities. These closures pose a serious challenge to power supply security. The rapid expansion of renewable energies requires reinforcement of flexible production capacities, but current market signals are preventing investment in these capacities. This situation could lead to a major structural crisis. Although the reserve margins of power capacities are still adequate in most countries, when the expected closures of power plants that are not profitable, or too pollutant, are taken into account, together with delays or cancellation of new projects, the situation is critical in several countries.

A new power market design is required

Since the market is not sending out the signals required for investment, a new market design needs to be defined. To meet the immediate problem of power supply security, several EU countries are putting in place capacity markets, intended to give an additional financial incentive to investors and ensure that the capacities needed to ensure a secure supply are available. The design of these mechanisms is however very complex, making it necessary to:

- determine the capacity required to ensure security of supply without compromising the options for demand-response at a higher price;
- integrate interconnection capacities and development of cross-border trading in order to achieve an EU internal market. The British example, with its first capacity auctions expected in December 2014, shows that the additional remuneration available to gas and coal plant operators has made it possible to stop closures of plants that are currently loss-making and envisage new investments.

These mechanisms only respond to the immediate concern: ensuring security of supply. A more far-reaching reform of the power system will nevertheless be necessary, including a structural reform of the European CO_2 allowances trading system, integration of renewable energies into the market, and completion of the EU internal market in electricity and gas. The continued liberalization of gas markets and diversification of supply should allow gas prices to be determined solely by market fundamentals, reinforce market liquidity, and allow electricity providers to obtain their supplies directly on the market. These are necessary conditions for the use of gas in the power sector.

Regulatory uncertainties, which still weigh on the EU power sector, make it difficult to forecast gas consumption in the sector. Projections by major institutions (IEA, Eurogas, Eurelectric) show that a recovery of the demand for gas is not expected during this decade. In the longer term, the role of gas in the power sector depends on the complex interaction of developments in the global and European energy market, which affect gas and coal prices, and European and national energy and climate policies, and have a strong influence on the electricity mix and its development. An analysis of national energy policies in the three biggest coal consuming countries in the EU — Germany, Poland and the UK — clearly shows that the transition to a low carbon economy varies greatly according to national energy sources and trade-offs made between the goals of sustainability, competitiveness and security of supply.

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