EUROPEAN
COMMISSION

Brussels, 13.10.2014
SWD(2014) 310 final

COMMISSION STAFF WORKING DOCUMENT

Trends and Developments in European Energy Markets 2014

Accompanying the document

COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS

Progress towards completing the Internal Energy Market

{COM(2014) 634 final}
{SWD(2014) 311 final}
{SWD(2014) 312 final}
{SWD(2014) 313 final}
{SWD(2014) 314 final}
{SWD(2014) 315 final}

Table of Contents

1. Energy position of the EU

1.1. EU energy consumption

1.1.1. Gross Inland Consumption

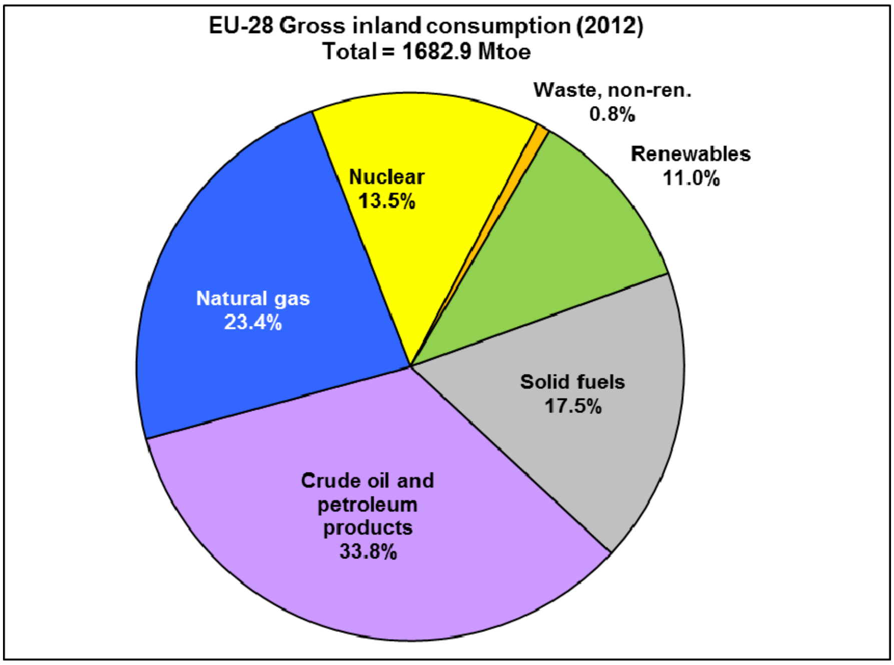
Gross inland consumption decreased by 4% between 2010 and 2012. Crude oil and petroleum products continued to dominate the energy mix, although their share decreased from 35.1% to 33.8%.

Gas consumption decreased both in absolute and relative terms against feeble economic performance, weak electricity demand and growing role of solid fuels and renewables in the power sector. The quantity of gas consumed went down by 11%, reaching 393 mtoe in 2012 and the share of gas declined from 25.1% in 2010 to 23.4%.

Nuclear energy retained its share, with the quantity consumed declining from 236.6 mtoe in 2010 to 227.7 mtoe in 2012.

Two energy sources saw an increase in consumption and share: solid fuels and renewables. Solid fuel consumption increased from 280 mtoe in 2010 to 293 mtoe in 2012, its share growing from 15.9% to 17.5%. Renewables consumption went up from 172.1 mtoe in 2010 to 184.4 mtoe in 2012, its share growing from 9.8% in 2010 to 11% of gross inland consumption in 2012.

Figure 1. EU-28 gross inland consumption (as % of total Mtoe) in 2012

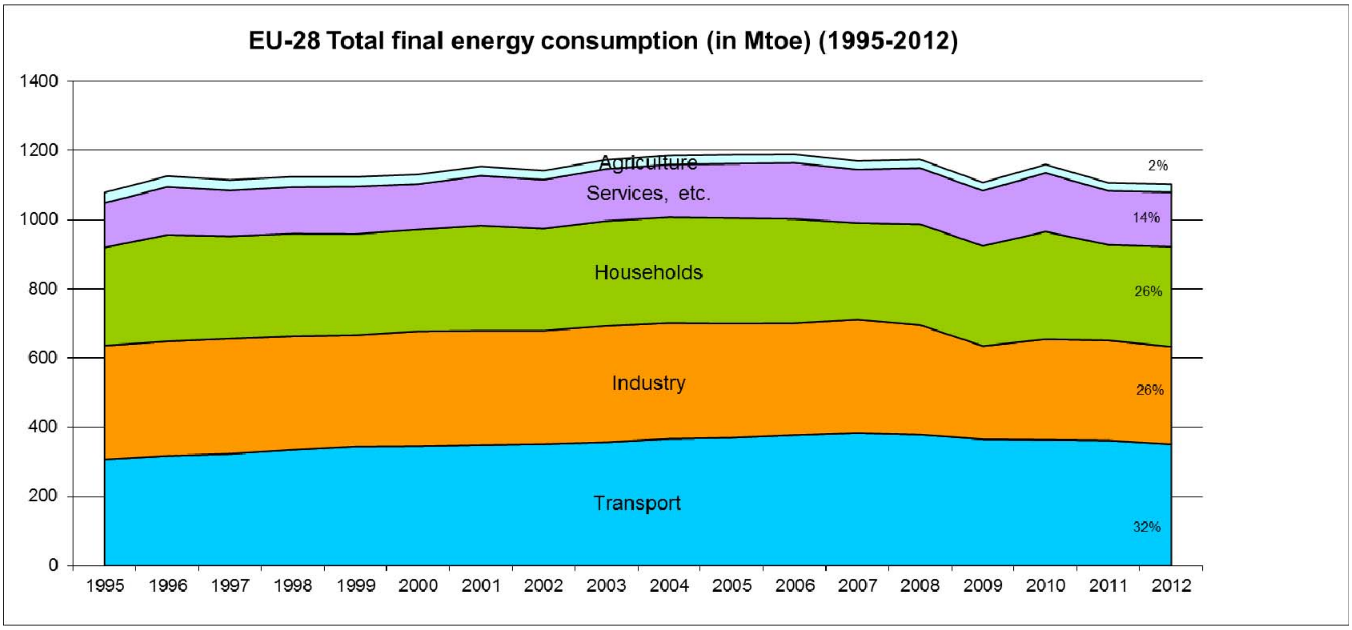


Source: Eurostat (preliminary data for 2012)

1.1.2. Uses of energy sources by sector

2012 final energy consumption was 5% below its 2010 levels with transport remaining the largest consumer of energy, followed by industry and households. Compared to 2010, the shares of different end use sectors remained fairly stable with transport at 32% (+0.5 p.p.), industry at 26% (+0.5 p.p.) and households at 26% (-0.7 p.p.).

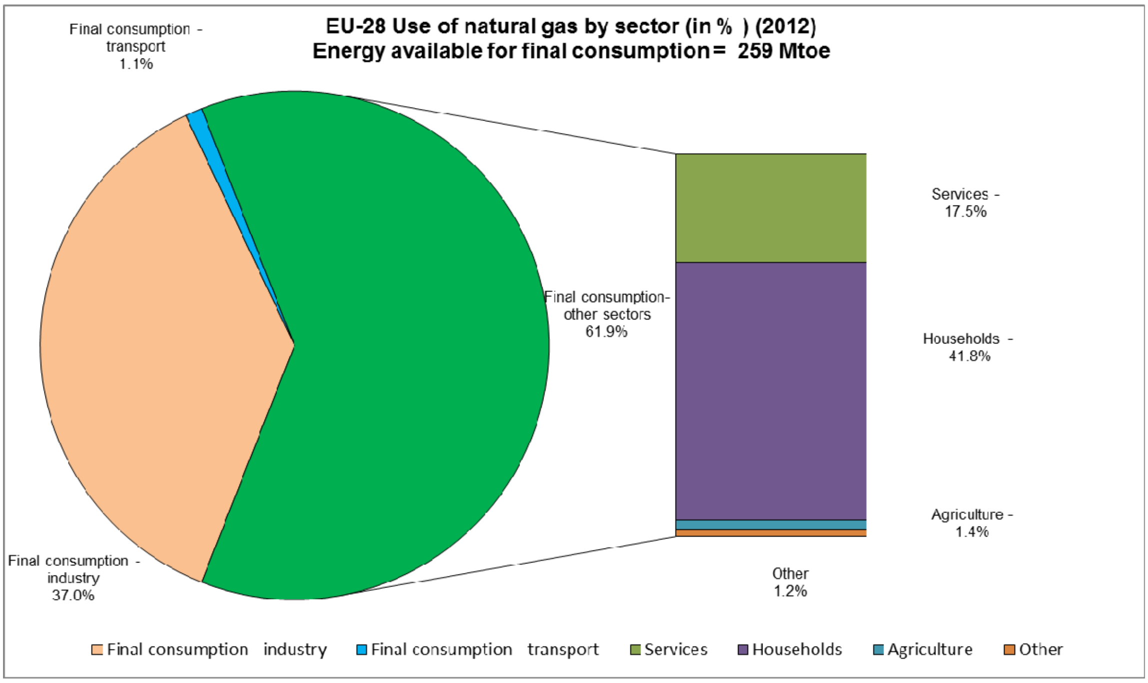
Figure 2. EU-28 total final energy consumption by end-use sector (in Mtoe) (1995-2012)



Source: Eurostat (preliminary data for 2012)

Looking by fuel, between 2010 and 2012 against weak economic performance industrial gas consumption levels decreased even though the share of industry in in natural gas consumption went up slightly. Household gas consumption level and share went down between 2010 and 2012.

Figure 3. EU-28 Use of natural gas by sector (final consumption) (2012)



Source: Eurostat (preliminary data for 2012)

In the area of petroleum products, shares remained unchanged between 2010 and 2012, with transport accounting for about two thirds and industry for 22%. Solid fuels are predominantly used in industry, with a share of 75%.

Figure 4. EU-28 use of petroleum products by sector (final consumption) (2012)

Source: Eurostat (preliminary data for 2012)

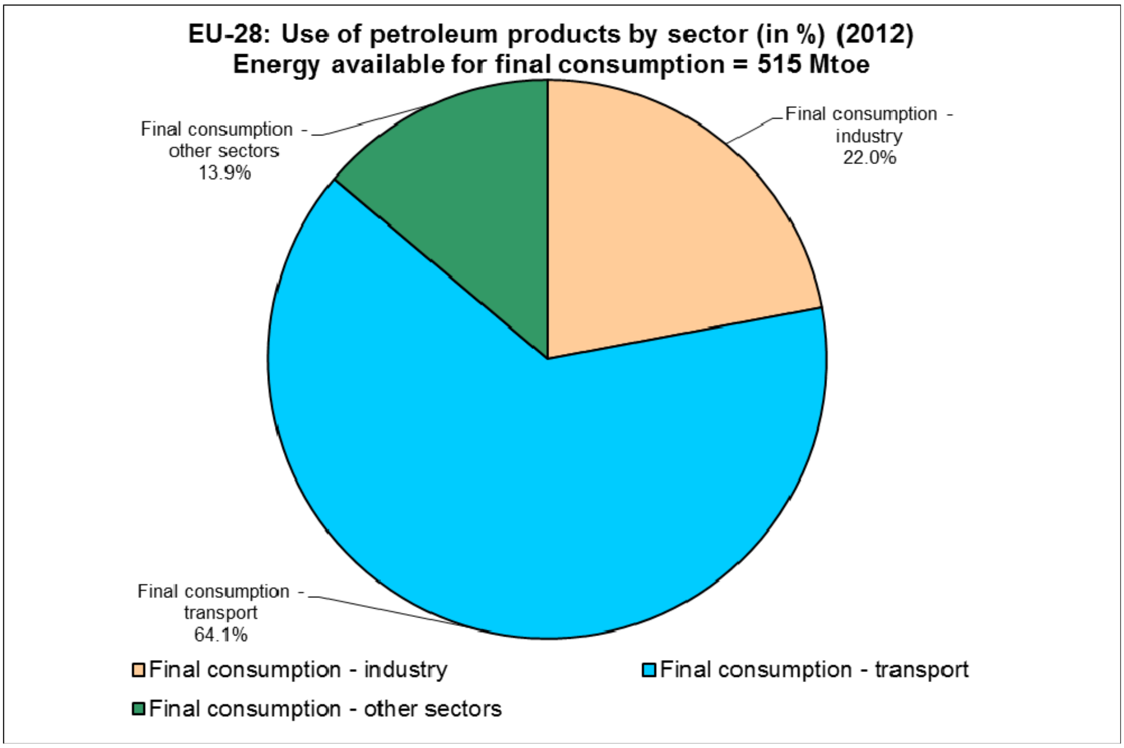
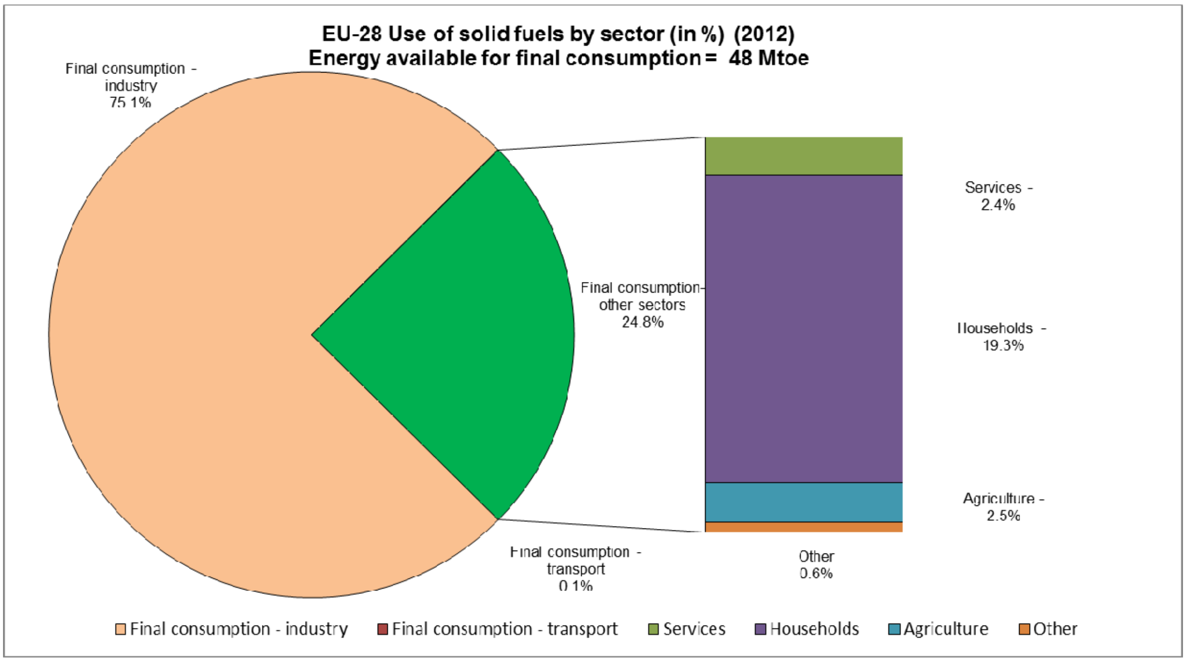


Figure 5. EU-28 use of solid fuels by sector (final consumption) (2012)

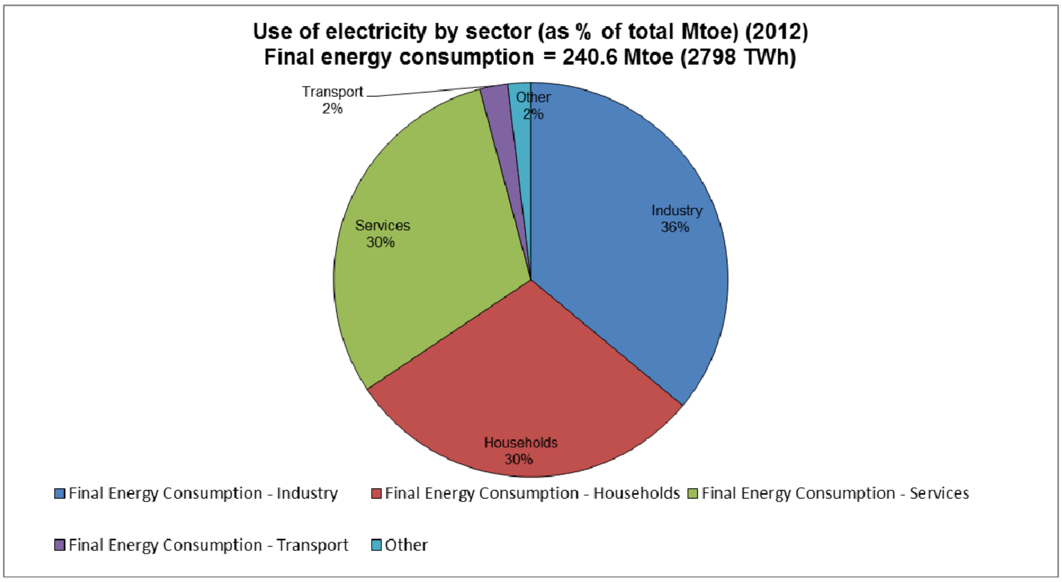


Source: Eurostat (preliminary data for 2012)

Turning to electricity, total consumption went down by 2% between 2010 and 2012. In 2012 industry continues to be the largest consumer of electricity and in 2012 accounted for 86.6 mtoe (down from 88.5 mtoe in 2010), with the share of industrial electricity consumption in total electricity consumption slightly down, reaching 36% of the total.

Households and services each account for 30% of electricity consumption and together accounted for 143.9 mtoe of electricity consumption in 2012 (households down by 2.5% and services by 0.6% relative to 2010).

Figure 6. Use of electricity by sector (2012)



Source: Eurostat (preliminary data for 2012)

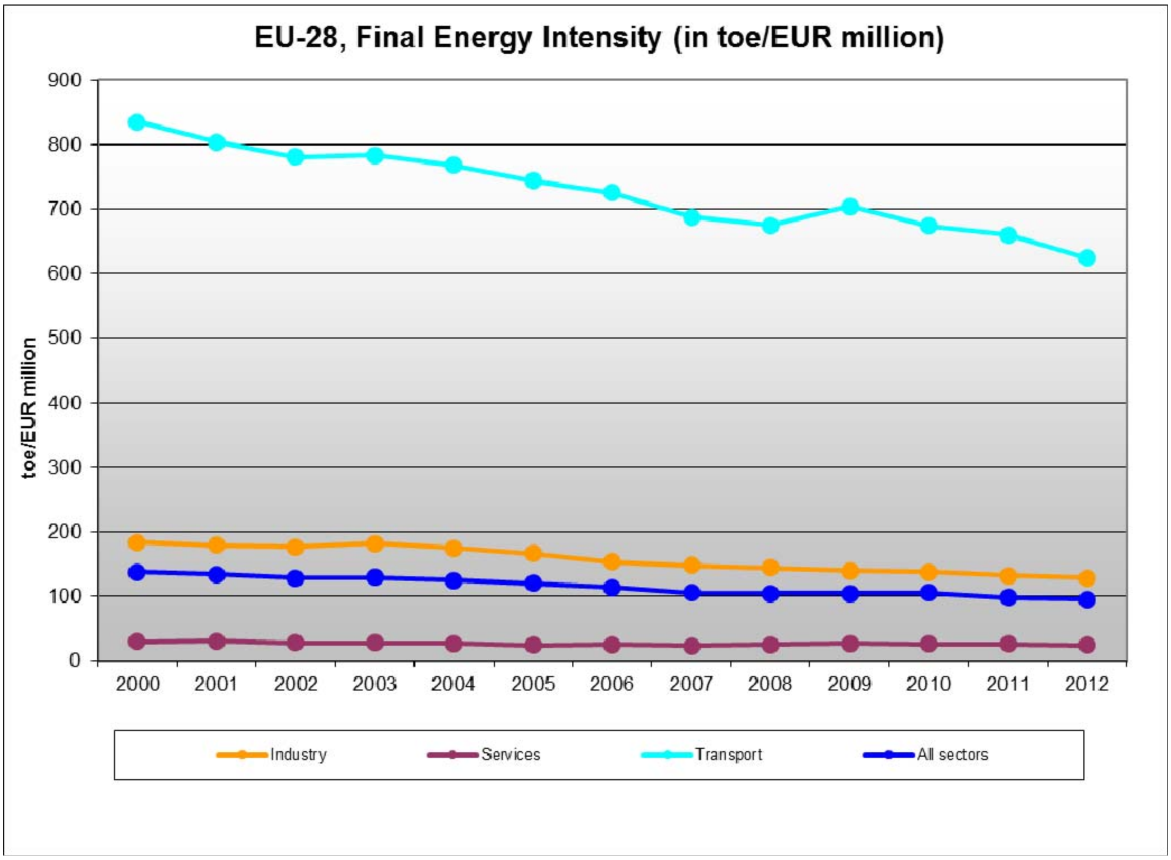
1.1.3. Energy intensity

Energy intensity is an indicator of the amount of energy used to produce a unit of economic output. Final energy intensity measures the energy efficiency of the economy against final energy consumption that is the amount of energy finally available to different sectors after conversion of energy sources.

At the level of the entire economy final intensity has been decreasing since the year 2000, although with a very minor increase between 2002 and 2003. This trend holds also for industry and transport: final intensity in the transport and industrial sectors has been on a downward trend apart from a slight increase between 2008 and 2009 for transport and between 2002 and 2003 for industry.

Figure 7. EU final energy intensity (in toe/million EUR, 2000-2012)

Source: Eurostat (preliminary data for 2012)


EU-28, Final Energy Intensity (in toe/EUR million)
toe/EUR million
900
800
700
600
500
400
300
200
100
0
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Industry
Services
Transport
All sectors

1.2. EU energy supply

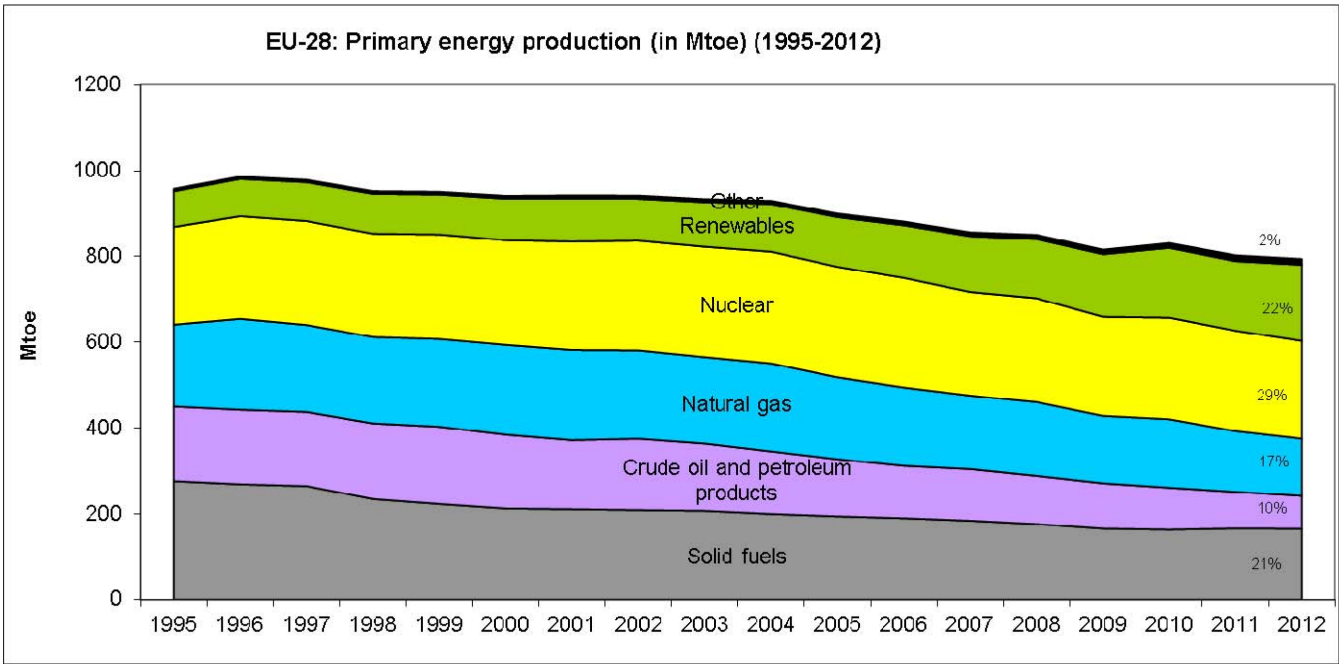
1.2.1. EU primary energy production

EU energy production decreased by more than 4.5% between 2010 and 2012, after a slight increase in 2010. Crude oil and petroleum products registered a 21% decrease in this period and gas production a 17% drop. Production of solid fuels showed a modest increase of 1.3%. Renewables production registered a 9% increase reaching 22% share of primary energy production – second only to nuclear at 29%.

Netherlands and the UK are the largest producers of natural gas in the EU and in 2012 respectively accounted for 43% and 26% of gas production in the EU; the third and fourth producers - Germany and Romania – has a 7% and 6.5% share of natural gas production in the EU. The UK is the largest producer of crude oil and petroleum products in the EU with a 60% share in 2012; Denmark is the second largest producer with a 13% share.

Between 1995 and 2012 the decrease in natural gas production reached 30%. Production crude oil and petroleum went down by 56% since 1995 and of solid fuels by 40%.

Figure 8. EU-28 Primary energy production (in mtoe) (1995-2012)



Source: Eurostat (preliminary data for 2012)

1.2.2. EU electricity generation

Total electricity generation in 2012 was 3295 TWh[1], stable year-on-year. Solid fuels and nuclear each accounted for 27% of electricity generation: up by 2 p.p. in the case of solid fuels and stable in the

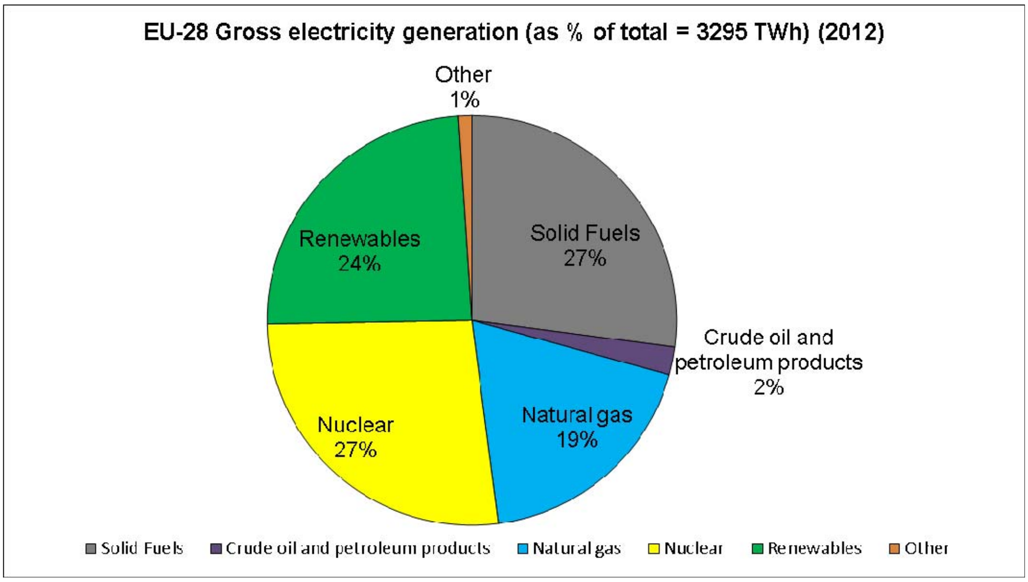
[1] Note that we would advise against presenting historical data 1995-2012 and comparing in detail (by fuel) 2011 to 2012 data in absolute terms due to a break in the series (methodological change) between 2011 and 2012.

case of nuclear in comparison to 2010. The share of natural gas in EU electricity generation continuously decreased – from 24% in 2010, to 22% in 2011 and 19% in 2012. The share of oil remained stable at around. Cyprus and Malta are the two Member States that rely almost entirely on oil for electricity generation.

In 2012 CO2-neutral sources, namely renewables and nuclear, accounted for 51% of EU electricity generation – up from less than 45% in the 90s.

Renewables accounted for 24% of electricity generation: 3 p.p. above the 2010 share. Hydro power remained the most important renewable source, representing 46% of renewable power generation, followed by wind (26% of renewable generation, up by 14% between 2011 and 2012) and biomass and waste (19% of renewable power generation, up by 12% between 2011 and 2012). In 2012 solar accounted for 9% of renewable electricity generation, up by impressive 50% between 2011 and 2012, following a doubling a production between 2010 and 2011.

Figure 9. EU-28 gross electricity generation (as % of total = 3295 TWh) (2012)



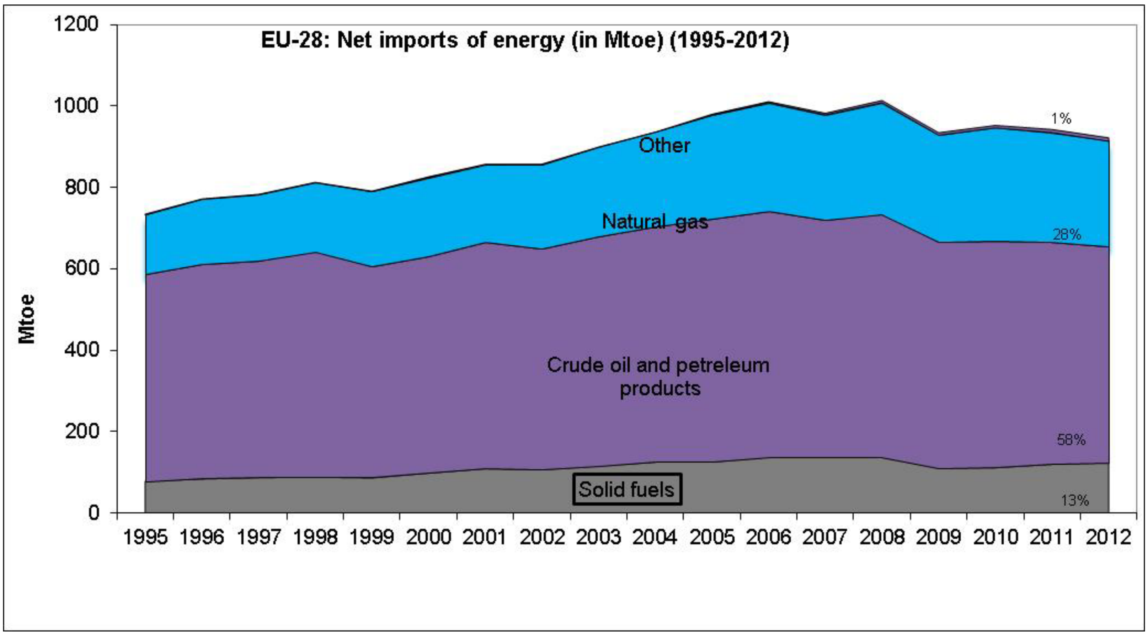
Source: Eurostat (preliminary data 2012)

1.2.3. EU energy imports

In line with lower energy consumption and electricity generation, in 2012 EU energy imports were 9% below the 2008 peak levels and indeed fell in third consecutive year, reaching 922 mtoe . After a significant drop over the period 2006-2010, imports of solid fuels and in particular of hard coal increased in 2011 and 2012. Solid fuel imports accounted for 13% of energy imports.

In 2012 imports of crude oil and petroleum products registered a slight fall (-4.6% compared to 2010) and accounted for 58% of energy imports. Natural gas imports reached a new peak in 2010, but dropped by 2% to 259 mtoe since then and as of 2012 account for 28% of energy imports.

Figure 10. EU-28 net imports of energy (in mtoe) (1995-2012)



Source: Eurostat (preliminary data 2012)

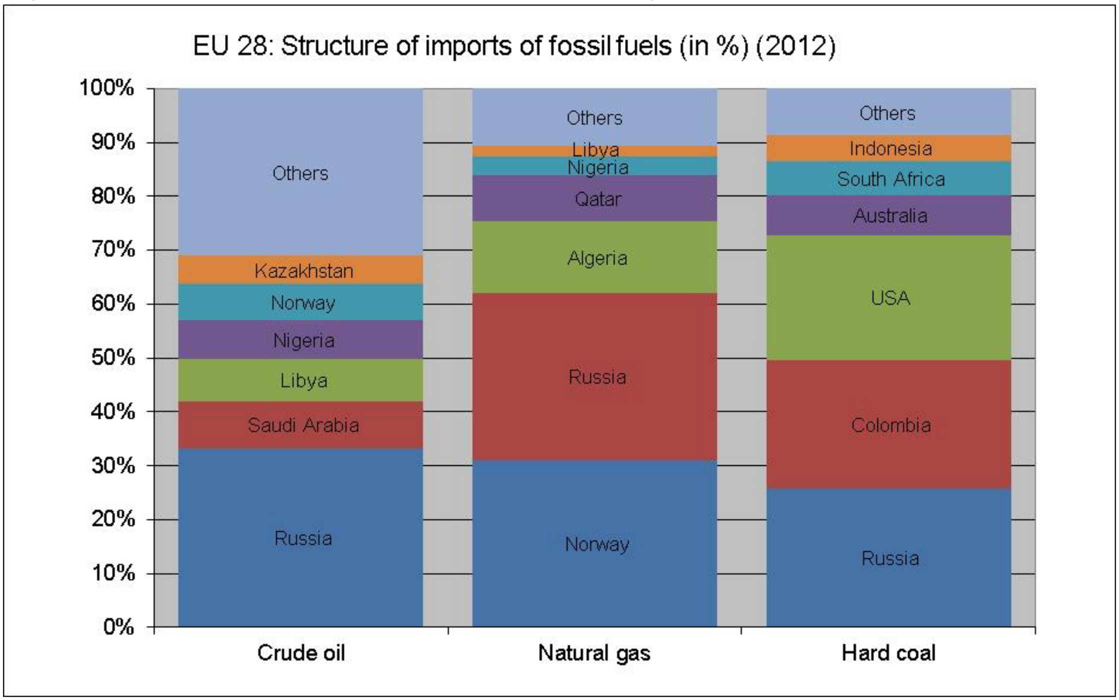
Partner countries differ from fuel to fuel, although some of them are key partners in a number of fuel categories. In 2012 Russia was the main exporter of crude oil and hard coal to the EU and on par with Norway in the natural gas exports.

The list of the top six exporters of crude oil to the EU changed between 2010 and 2012 with Saudi Arabia, Libya and Nigeria exporting more to the EU than Norway that was previously second to Russia in crude oil exports.

When it comes to hard coal exporters to the EU, Colombia and the US remained the second and third largest exporters. The increase in US exports of coal is related to increasing consumption of gas domestically.

Against the background of weaker demand in the course of 2012 exports of natural gas from Norway to the EU rose to levels comparable with Russian natural gas exports. Norwegian companies have been actively changing their pricing policy with new Statoil contracts negotiated purely on a spot indexation basis. At the same time, Gazprom maintains that the oil price link is indispensable for long-term business planning, but has been offering a number of discounts in its long-term prices between 2011 and 2013 to a number of companies. By changing the price setting mechanism to gas-on-gas basis, Norway was able to retain consumers and in 2012 increase market share to the detriment of other exporters such as the Russian Federation and Algeria.

Figure 11. EU-28 imports of fossil fuels by country of origin (2012)



Source: Eurostat (preliminary data 2012)

1.2.4. EU import dependency

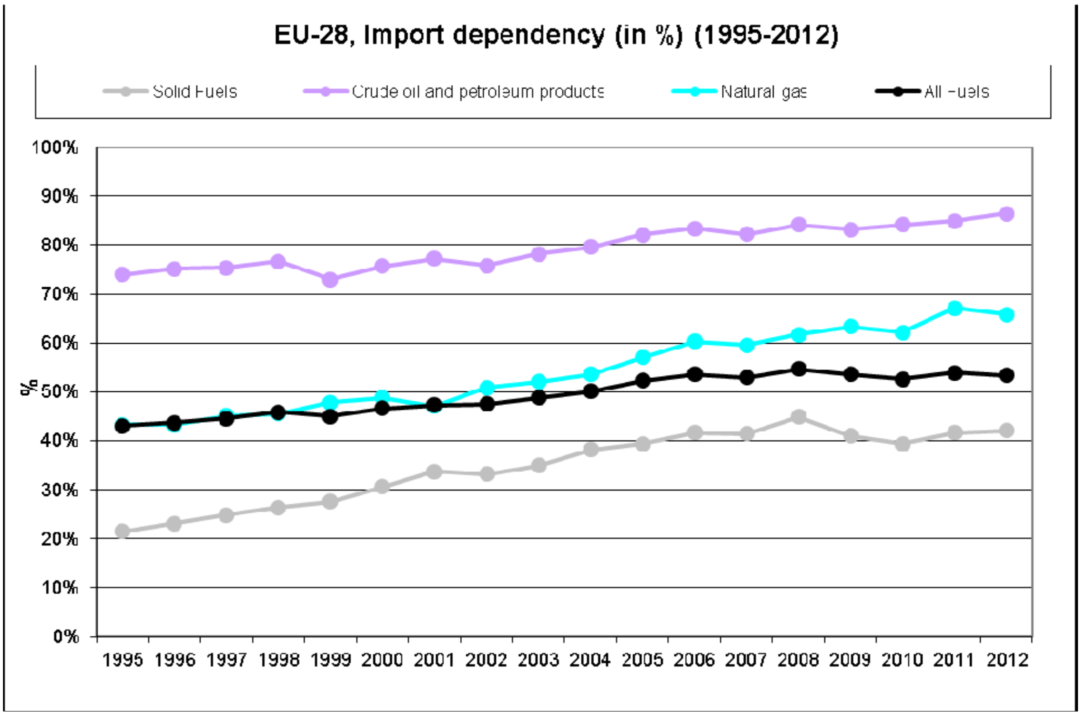
The EU is the world's largest energy importer. The majority of MS are highly dependent on imports of oil and gas. A few MS have significant production that makes a considerable contribution to the EU energy balance. The UK and Romania satisfy a sizeable share of their needs with domestic production, while the Netherlands is an important net exporter of gas and Denmark of crude oil and petroleum products.

The overall energy import dependency of the EU peaked in 2008, before falling in 2009 and 2010. At 53.3£ in 2012, overall energy dependency in 2012 it was slightly higher than in 2010 driven by an increase in the import dependency for solid fuels and for crude oil and petroleum products. The downturn in the primary production of hard coal, lignite, crude oil and natural gas has led to a situation where the EU is increasingly reliant on primary energy imports in order to satisfy demand. Yet, at 42.2% import dependency of solid fuels is more than 2 p.p. below its peak in 2008. At the same time in 2012 crude oil and petroleum product dependency reached a historic high of 86.4%.

The import dependency for gas peaked in 2011 before falling by 1.3 p.p. in 2012 to 65.8%. This dynamics was underpinned by a fast decrease in gross inland consumption of gas (-12% between 2010 and 2012) and a somewhat more moderate drop in import volumes (-5% between 2010 and 2012).

Figure 12. EU import dependency (in %) (1995-2012)

Source: Eurostat (preliminary data for 2012)



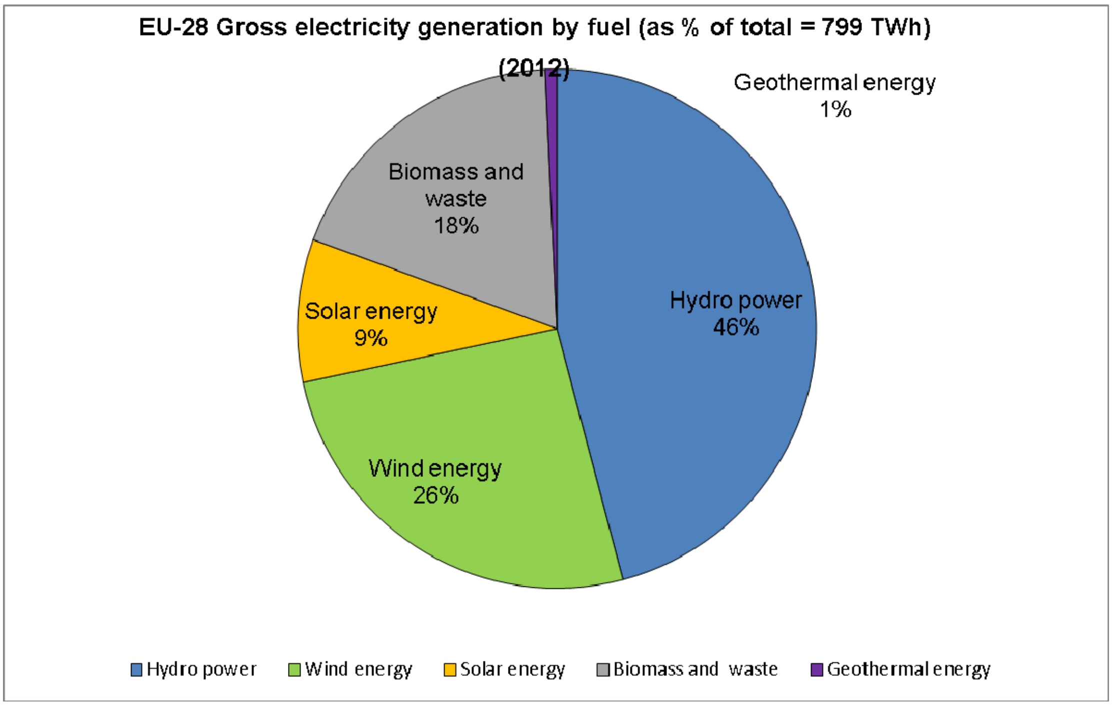
Electricity from RES

In 2012 the production of renewable electricity reached 799 TWh, an increase of more than 13% compared to 2011. Hydro power is the most important renewable electricity source and accounts for 46% of renewable electricity generation in the EU.

The importance of RES other than hydro has been growing. Between 2011 and 2012 electricity from solar energy saw an impressive growth of more than 50%, with its share in renewable electricity generation reaching 9%. Electricity from wind registered a growth of about 14% and electricity from biomass and waste of about 12%.

Figure 13. EU-28 Gross Electricity Generation by Renewable Energy Source

Source: Eurostat (preliminary data 2012)


EU-28 Gross electricity generation by fuel (as % of total = 799 TWh) (2012)
Geothermal energy 1%
Biomass and waste 18%
Solar energy 9%
Hydro power 46%
Wind energy 26%
Hydro power
Wind energy
Solar energy
Biomass and waste
Geothermal energy

2. Recent developments in the European wholesale markets of natural gas

The gross domestic product of the EU Member States registered a year-on-year increase of 0.5% during the third quarter of 2013. This ended a sequence of 5 consecutive quarters with negative or zero growth rates. The prolonged economic slowdown, still not over for some Member States, and the prospects of gradual recovery affected the economic decisions and actions of market participants in the EU energy markets throughout 2012 and 2013.

Further to the difficult macroeconomic context, the actors in the EU markets of natural gas had to take into account the long-term prospects of the industry in terms of the replacement of decreasing indigenous production with imports from extra-EU trading partners and in terms of a general decoupling of energy consumption and economic growth, as illustrated in **Figure 14**.

The consumption of natural gas in 2012 stood at 4 500 TWh, representing a 2.7% decrease on a yearly basis. No lower level was recorded since 1999. Based on a preliminary 2013 data from Eurostat, 18 Member States registered further declines of gross inland consumption.

Among the factors affecting these developments were the low levels of industrial demand and relatively mild weather conditions which affected demand for heating. The reduced consumption from power plants turned into an important factor: in 2012 and 2013 gas power plants were outcompeted by coal (as demonstrated by clean spark and dark spreads[2]) and RES.

Table 1 illustrates the reduced intake from power plants. Based on data from *Platts – Bentek*, it appears that in 6 years, the gas consumption of power plants was reduced more than 3 times in Spain almost 2 times in the UK whereas Italian power plants reduced the in-take by more than 13 bcm per year.

[2] **Dark spreads** are reported as indicative prices giving the average difference between the cost of coal delivered ex-ship and the power price. As such, they do not include operation, maintenance or transport costs. Spreads are defined for a coal-fired plant with 35 % efficiency. **Clean dark spreads** are defined as the average difference between the price of coal and carbon emission, and the equivalent price of electricity.
Spark spreads are indicative prices showing the average difference between the cost of gas delivered on the gas transmission system and the power price. As such, they do not include operation, maintenance or transport costs. The spark spreads are calculated for gas-fired plants with standard efficiencies of 50% and 60%. **Clean spark spreads** are defined as the average difference between the cost of gas and emissions, and the equivalent price of electricity.

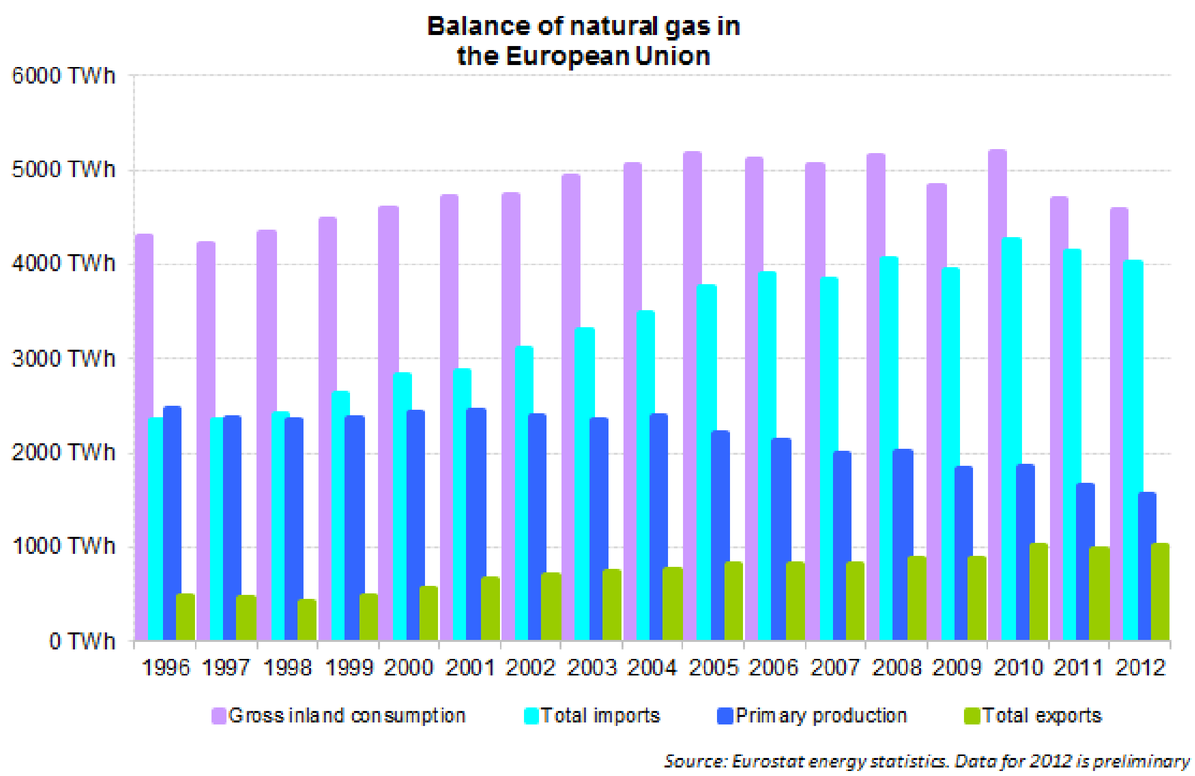
Table 1. Annual gas intake from power plants (bcm)

	2008	2009	2010	2011	2012	2013
Italy	33.4	28.7	29.8	27.5	24.2	20.1
UK	24.8	23.1	25.3	19.5	13.2	13.1
Spain	16.0	13.7	11.6	9.4	7.2	4.8
Belgium	n.a.	n.a.	n.a.	7.1	8.4	7.4
France	n.a.	n.a.	2.2	2.5	1.5	1.2

Source: Platts-Bentek

As shown in **Figure 14**, the gradual decline in EU domestic production of natural gas continued throughout 2012, with the average decrease since the year of peak production (2001) amounting to 4%.

Figure 14. Balance of natural gas in the EU

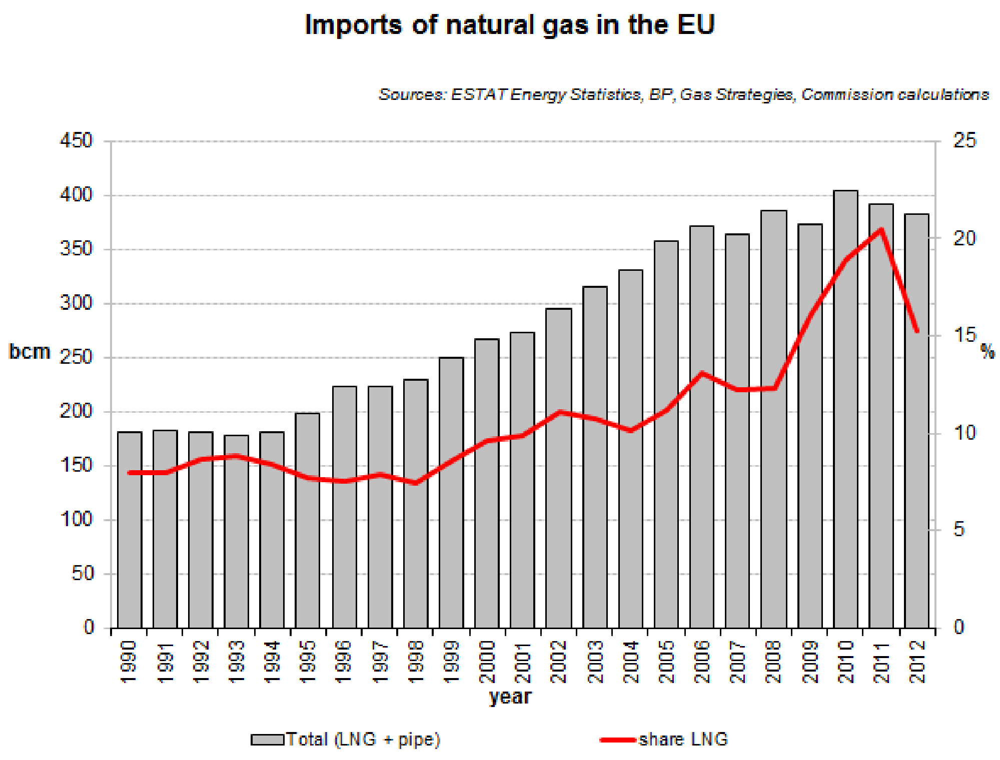


Source: Eurostat (preliminary data 2012)

In 2011 and 2012 falling imports of natural gas could also be observed along with falling consumption. This development is in contrast to observed trends in the three previous years. According to preliminary Eurostat data for 2012, the **extra-EU gas imports** totalled 3 592 TWh (about 341 bcm[3]) in 2012, with the most important trading partners being Norway and the Russian Federation (31% each), and Algeria (13%) and Qatar (8%). The combined part of Nigeria, Libya, Egypt, Trinidad & Tobago and others was less than 8%[4]. An additional 40 bcm was imported by MS from intra-EU sources.

The EU 28 import dependency[5] of natural gas increased from 0.43 in 1995 to 0.49 in 2000, to 0.57 in 2005, to 0.62 in 2010 and reached 0.66 in 2012 (preliminary figures). The majority of Member States tend to rely on imports as the major source for the gross inland consumption.

Figure 15. Imports of natural gas in the EU-28



Source: Eurostat (preliminary data 2012)

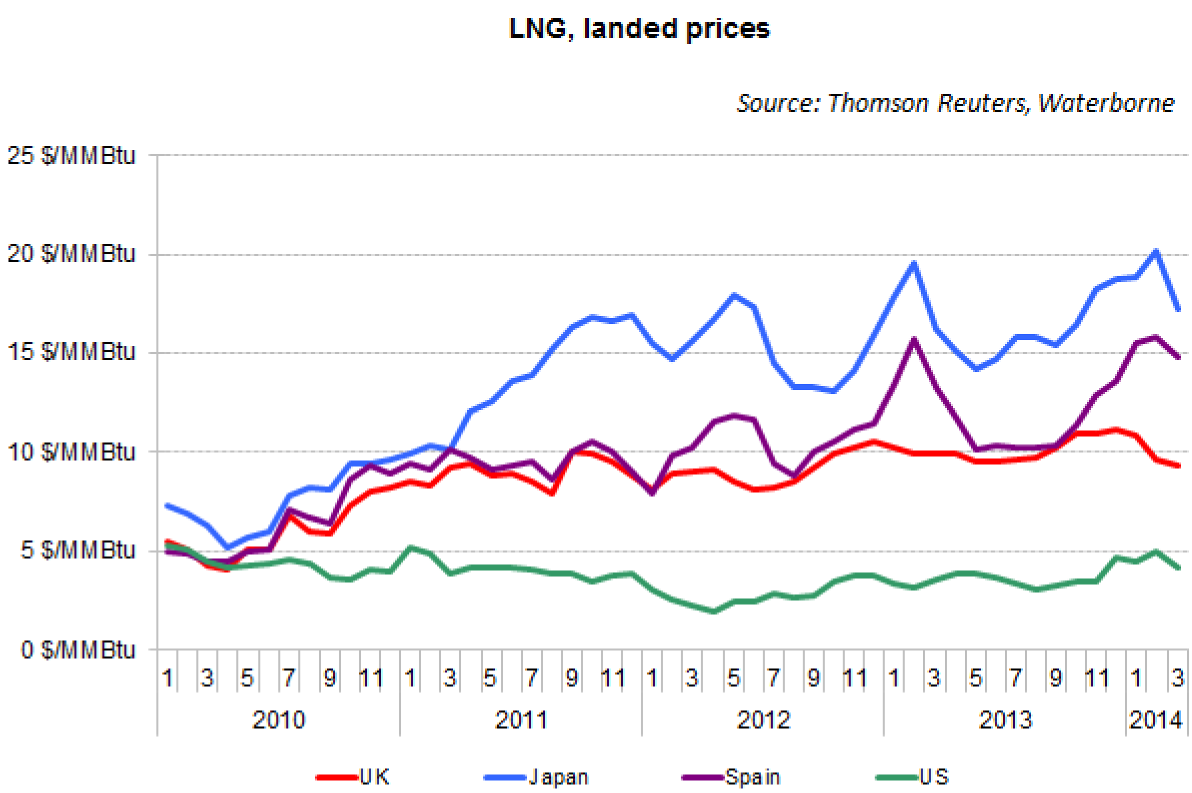
[3] Conversion rate used: 1 bcm = 10.533 TWh (normal cubic meter, measured at 0 degree Celsius and 760 mm Hg), as defined by IEA Natural gas information:

[4] The "non-specified" trading partner category of Eurostat may contain gas coming from the above-mentioned countries.

[5] Import dependency is defined as the ratio of net imports over the sum of gross inland consumption and bunkers. The EU import dependency is net of intra EU trade; calculated at national level however, it includes the intra EU trade.

Between 2011 and 2012 the EU 28 total imports of natural gas decreased by 108 TWh, which is equivalent to slightly more than 10 bcm. The import evolution by transport delivery mode was quite different. As illustrated in **Figure 15**, an increase of imports of natural gas delivered **by pipelines** (12 bcm / year) was more than matched by a strong decrease of LNG deliveries (more than 22 bcm / year). As a result, the relative share of LNG in total gas supplied dropped from 20% in 2011 to 15% in 2012.

Figure 16. LNG prices, selected countries



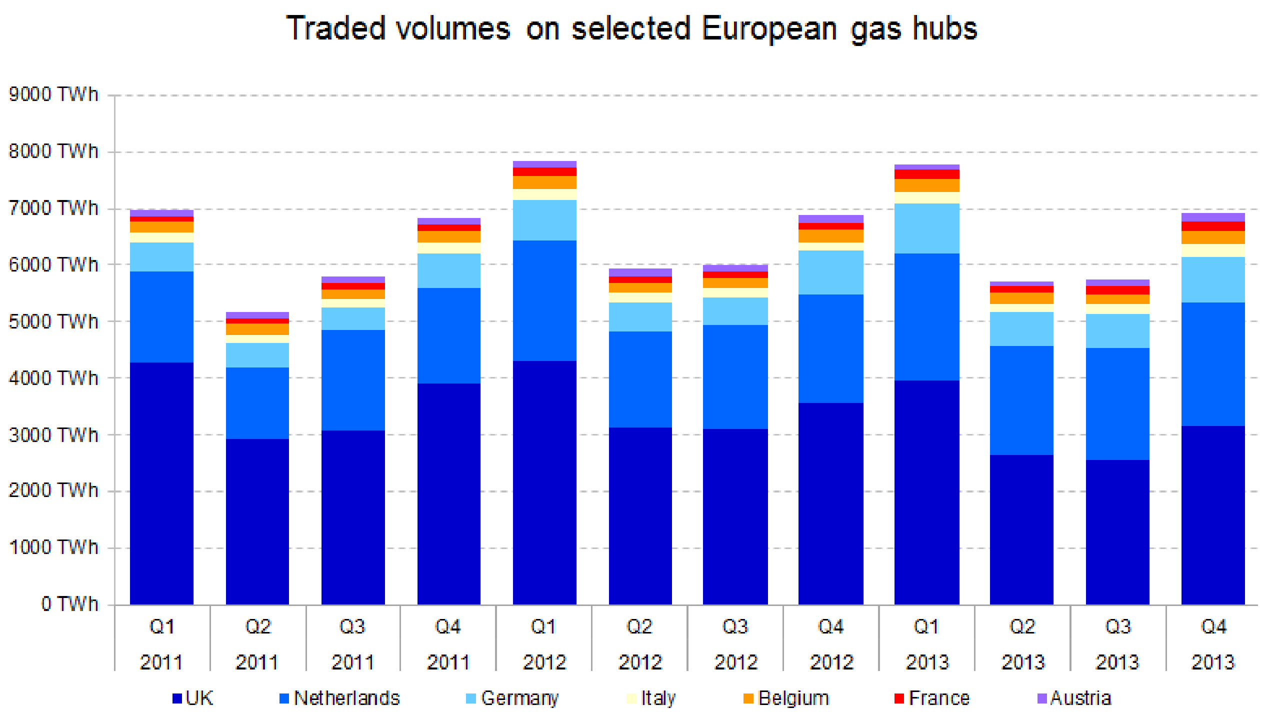
The diversion of LNG cargoes to the Pacific basin in the aftermath of Fukushima is well documented[6] and **Figure 16** provides further evidence for the more attractive pricing conditions in Japan (similar price levels were also observed in South Korea and China). The relative inflexibility of some market participants who are bound to long term contracts with take or pay obligations may be another reason of the decreasing relative share of LNG in total imports.

[6] Check for example the regular publications of the Market observatory for energy here: http://ec.europa.eu/energy/observatory/gas/gas_en.htm

Based on the latest report from *Prospex Research*[7], the total traded volumes (including exchange spot and forward and OTC cleared and non-cleared) of the EU markets of natural gas stood at 32 200 TWh in 2011, a fifth consecutive year of strong growth. This number compares to a gross inland consumption in the EU of 4 600 TWh. The gas traded volumes are also approximately 4 times bigger than those recorded for electricity.

The UK market is by far the most liquid, recording trading volumes above 20 000 TWh. Market operators on the Dutch and German markets exchanged respectively 6 500 TWh and 2 100 TWh. The highest churn factors[8] were in the UK (23.6) and the Netherlands (16.3), followed by Austria (4.4), Belgium (4.2) and Germany (2.5)[9]. OTC accounts for more than 80% of the traded volumes. Similar to electricity markets, the cleared OTC has a much smaller share than the non-cleared OTC under which the gas volumes from the long term contracts are recorded.

Figure 17. Traded volumes of natural gas in selected hubs



Sources: National Grid (UK), GTS and LEBA (Netherlands), Huberator (Belgium), Gaspool (Germany), NCG (Germany), GRTGaz (France), Snamrete (Italy), CEGH (Austria)

[7] "European Gas Trading 2012", Prospex Research, www.prospex.co.uk

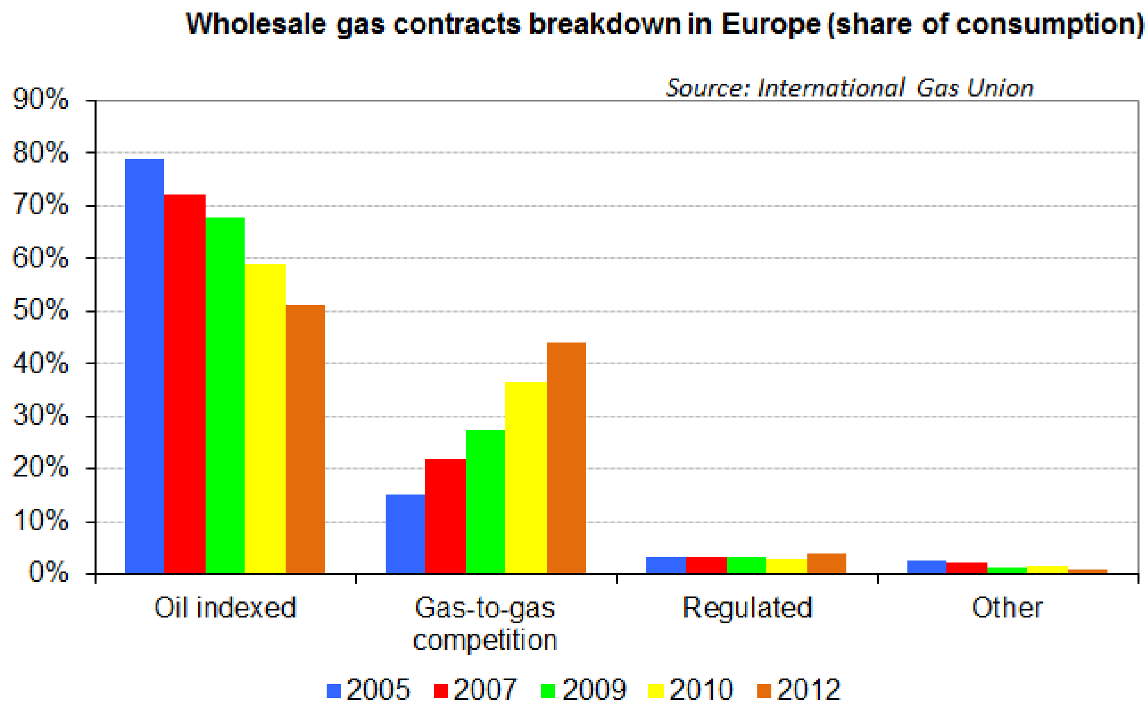
[8] The churn factor is defined as the ratio of traded volume to physical consumption. It informs about the liquidity of the market place and the quality of the pricing signal that is discovered on that market.

[9] The low churn factor for Germany on the gross market is due to the important share of long-term contracts.

As illustrated in **Figure 17**, in the period after 2011 hub traded volumes stabilized, registering varying fortunes across hubs (Netherlands[10] and the German hubs were among the more notable increases and hub volumes in the UK and Austria went down).

The evolution of the overall traded volumes is not yet clear. Judging by data from the *International Gas Union* (**see Figure 18**), the relative share of natural gas delivered in the EU under hub based gas-on-gas competition continued to increase and reached almost 50% of the overall EU consumption. For the Member States that have developed mature hub trading, this share is well above 80%.

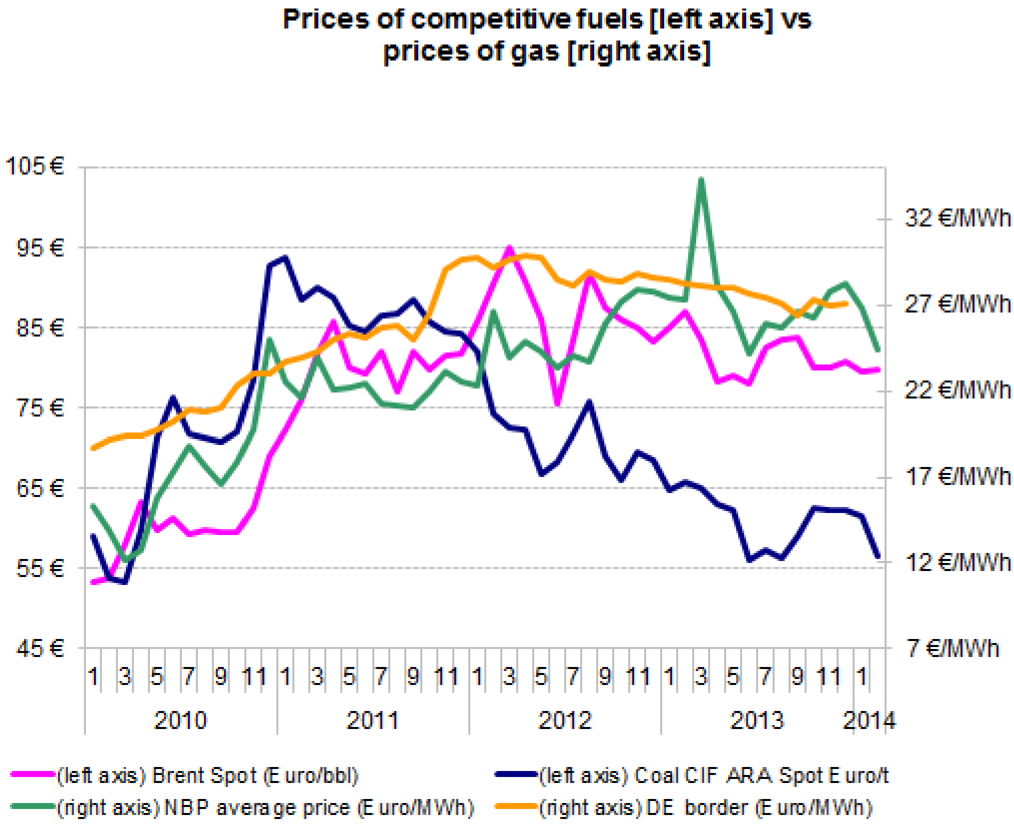
Figure 18. Break-down of natural gas contracts by pricing mechanism in Europe (in share of consumption)



Another indication of the difficult situation facing the gas fired power generators is provided by **Figure 19** which traces the evolution of prices of competitive fuels against selected benchmark prices for gas in the EU. A persistent surplus of steam coal on the US market resulted from the gradual crowding out of coal by shale gas. These extra volumes of coal from the US but also Columbia and other countries were made available in the EU at competitive prices. In addition, a structural oversupply of ETS allowances kept a downward pressure on carbon prices.

[10] GTS reports hub and OTC trades for the Netherlands.

Figure 19. Evolution of prices for competitive fuels versus European gas price benchmarks



Source: Platts, BAFA (DE border)

It is also interesting to observe the dynamics of gas prices by comparing the pure hub benchmark (such as the NBP price) against a hybrid price containing hub and oil indexation elements (such as the German border price). Whereas the hub benchmark was traded at a discount since 2010 and earlier, the spread was reduced by 2012 and in some cases hub prices were above the German border price.

One factor that could explain the decrease of the spread is the more pronounced part of hub prices in the German border price as more and more suppliers are turning to this pricing mechanism; this can also be witnessed by the divergence of the German border price from a pure oil indexed benchmark with delivery in North Western Europe, such as the *Platts* Gas Contract indicator.

Another factor may be linked to the relative stability of the major oil benchmarks providing a support for the long term gas prices indexed on oil. As illustrated by the map on next page, the divergence of the wholesale gas prices across the EU decreased somewhat; yet Member States with few supply choices were facing a tougher bargain and higher prices.

Figure 20. Comparison of EU-28 average wholesale gas prices during first half of 2014

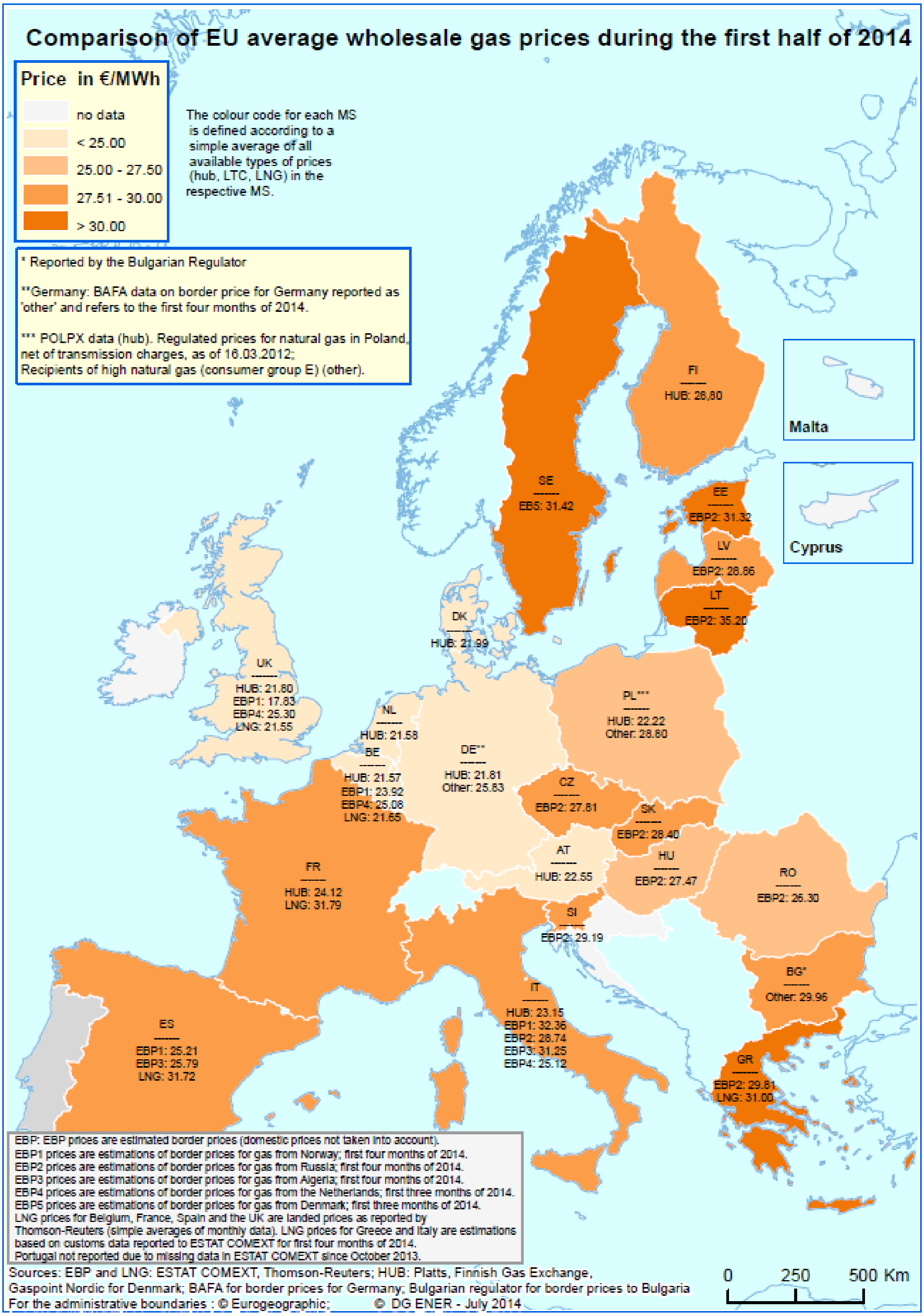


Figure 21. Evolution of the main gas hub benchmarks

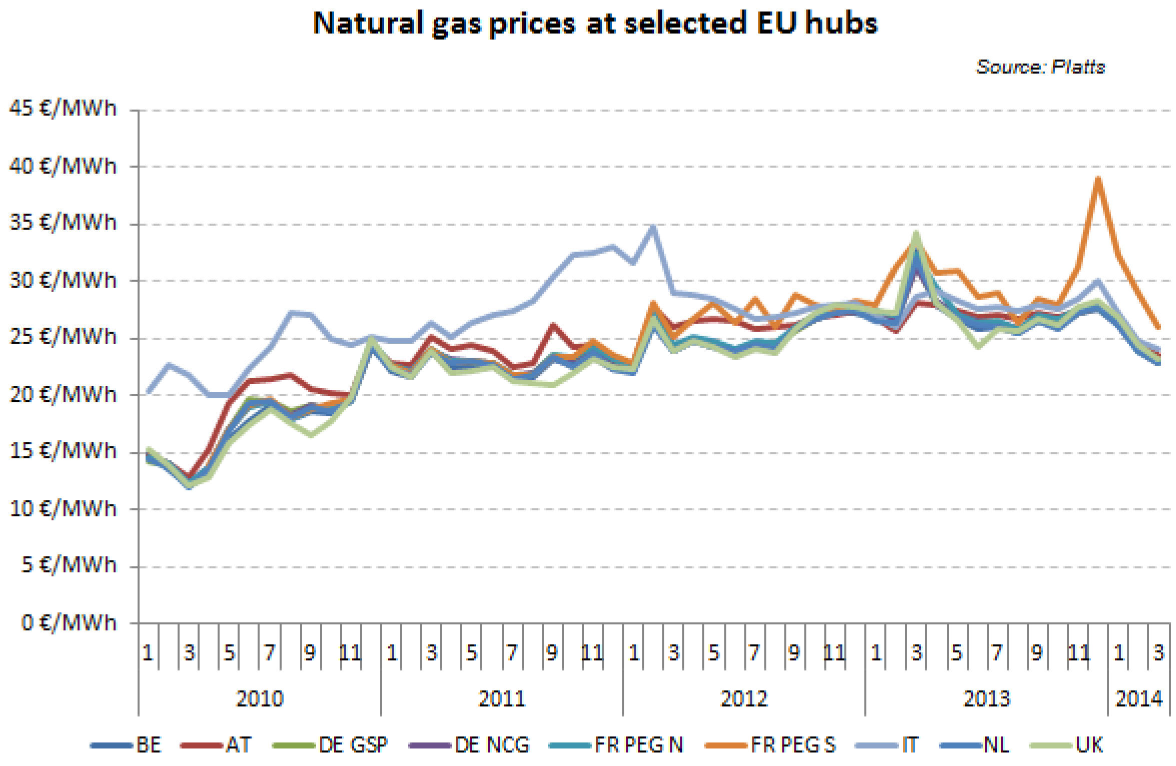


Figure 21 illustrates the strong correlation across the EU hub prices. By the second half of 2012 the Italian benchmark gradually aligned with the Austrian and then continental hub prices. The French PEG South price followed an opposite evolution, slowly diverging from the more traded PEG North price and then from the other hub prices as well. This evolution is most likely linked to the persistently low levels and capacities of gas storage, and the need of a strong pricing signal to ship gas flows from North to South.

As a rule, the hub prices gave a fair representation of the supply and demand conditions in different trading areas and market participants were using the available trading opportunities to make sure prices were aligned. As shown in **Table 2**, the operation of the gas markets improved significantly in the last couple of years, as shown by the decrease of FAPD events[11] that measure irrational adverse flows.

[11] Flow against price differentials (FAPDs): 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

Table 2. FAPD events by selected adjacent areas

	2011	2012	2013
# observations / year	251	248	251
BE-NL	25	6	13
BE-UK	4	17	7
NL-UK	83	28	28
FR PEG Nord – FR PEG Sud	2	1	0
AT-IT	0	0	0
AT-DE	133	112	6
Average FAPD events selected	**41**	**27**	**9**

Sources. (1) Price data: Platts; (2) Flow nomination data: Fluxys, BBL, ENTSOG TP

The successive cold spell events that hit the Northern part of Europe at the end of the heating season were another period of significant price swings. The majority of countries in North and North-Western Europe experienced harsher than usual meteorological conditions throughout the 2012 – 2013 winter season. Based on heating degree days data (HDD)[12] from the Joint Research Centre of the European Commission, the March temperatures were the furthest apart from the long term average, with some MS recording more than 100 HDDs in addition to the long term average. In two separate events during the second and third week of the month, the temperatures across the UK were 6^0C – 8^0 C cooler than the long term average for several days.

Prior to March 2013, market operators were withdrawing gas from storages at a faster-than normal rate. The March cold spell events accelerated further the withdrawal and as the winter season was coming to an end, a new minimum level of 2.71% was reached on 13 April 2013 in the NBP area. French storage levels were also extremely low and the minimum was reached on 10.04.201 (6.23%).

threshold of price difference under which no FAPD is recorded. The minimum threshold for gas is set at 0.5 €/MWh.

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.

[12] Heating degree days (HDDs) express the severity of a meteorological condition for a given area and in a specific time period. HDDs are defined relative to the outdoor temperature and to what is considered as comfortable room temperature. The colder is the weather, the higher is the number of HDDs. These quantitative indices are designed to reflect the demand for energy needed for heating purposes.

3. Recent developments in the European wholesale markets of electricity

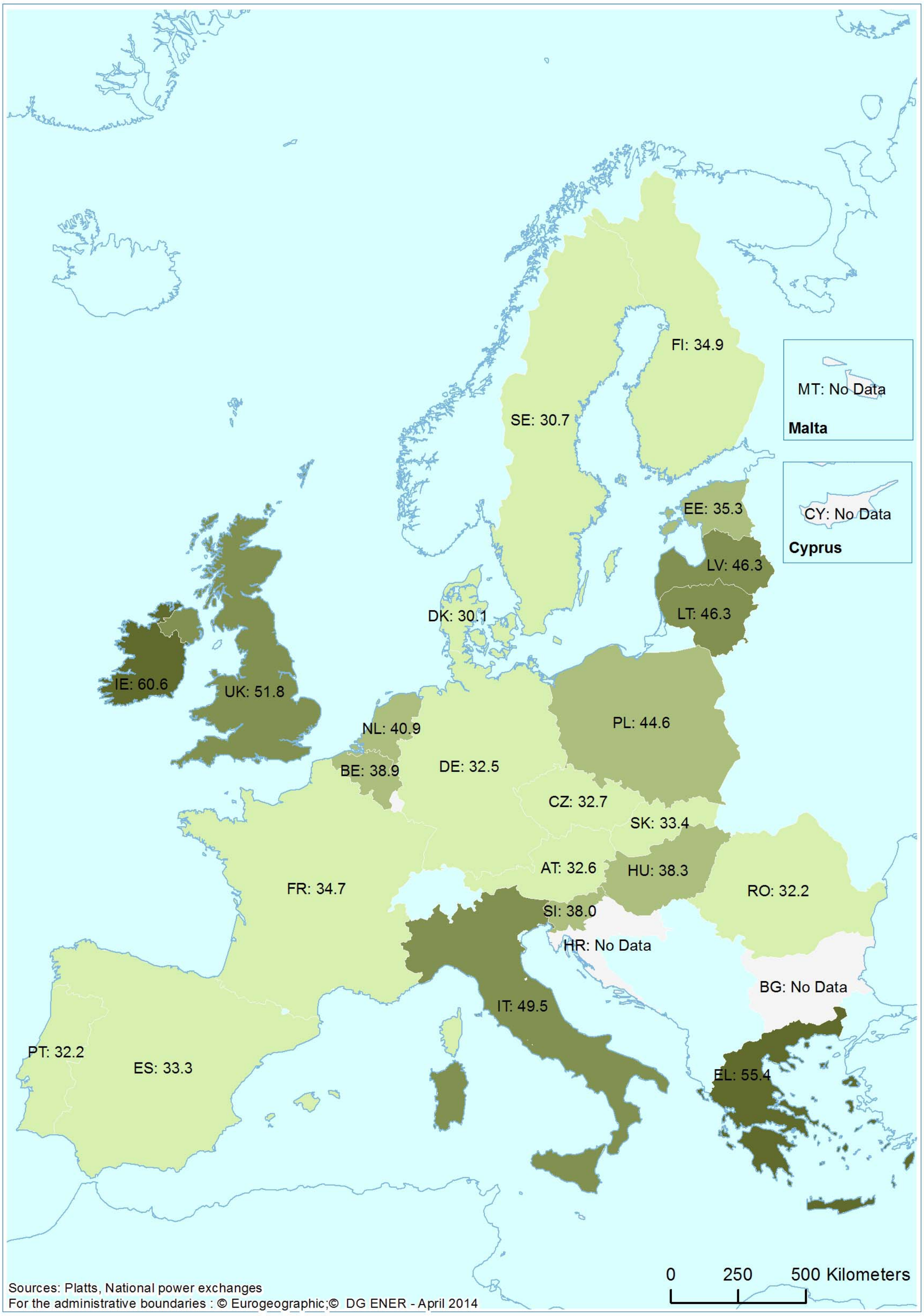
The map on the next page (**Figure 22**) illustrates the annual averages of day-ahead wholesale baseload electricity prices in 2013 in the member states of the European Union, Norway and Switzerland:

Power generation costs and wholesale prices are primarily influenced on one hand by supply side drivers, such as the structure of the power generation mix, the amount of generated power compared to domestic needs or the availability of power imports and exports and other factors, for example carbon emission allowance prices. On the other hand, the demand side is affected by the electricity need of households (lighting and heating needs), and the industrial demand for electricity, primarily depending on the general performance of the economy. On the longer term both household and industrial electricity demand is also impacted by energy efficiency policies.

In those countries, where the contribution of hydro energy is significant in power generation (e.g.: Spain, Portugal, Sweden, Austria, Norway or Switzerland) the amount of precipitation significantly impacts the generation costs and the wholesale power price level. In most of these countries the 2013 average power prices were among the lowest in Europe. In countries like Germany, where the influence of solar and wind power generation rapidly increased during the last couple of years, abundant renewable supply assured one of the lowest average price in 2013 in the EU. German power generation trends have significantly impacted the price level in Central and Eastern Europe. Prices in this region also depend on the availability of electricity interconnections to neighbouring countries and regions, such as the Balkans.

Prices in Italy, Ireland the United Kingdom and the Netherlands were among the highest in the EU in 2013, either because of the lack of sufficient interconnection capacities to neighbouring power markets (Italy and Ireland) or because of the dominance of expensive generation fuels in setting the marginal price in the wholesale market (natural gas in the case of the Netherlands and the UK). In the UK changes in the energy mix, i.e. related to significant coal-fired generation capacities taken offline in 2013 according to long standing plans, have created an upward pressure on domestic wholesale power prices in the short term, pending new capacity coming on-stream.

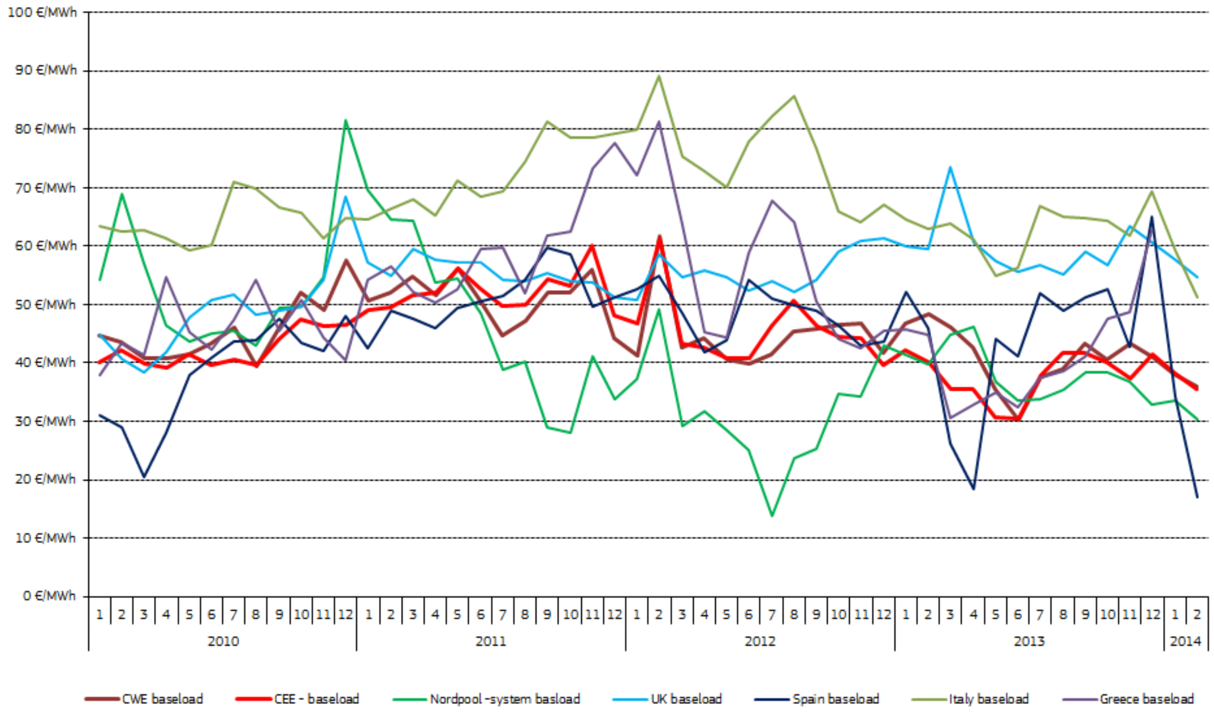
Figure 22. Comparison of average wholesale baseload electricity prices, first semester of 2014



Taking a look at the longer term trends on **Figure 23**, the findings of the analysis above on the 2013 average prices can be reinforced. The important role of hydro generation can be tracked in the volatility of Spanish and Nordic power markets; with sudden shoot-ups and falls in power prices, depending on hydro availability. Italy had a significant price premium to other European peers during the last four years, and the UK has had a price premium since 2012 as gas-fired generation has become less competitive to coal.

Central Western and Central Eastern European wholesale electricity prices showed a high degree of convergence in the last four years, as German power prices served as a peer to many markets in both regions. In the Southern European countries (e.g.: Spain, Italy or Greece) high summer temperatures can significantly increase power demand (mainly for cooling needs in households) and wholesale prices in the market. On the other hand, severe cold snaps affecting the whole European continent, like in February 2012, can result in sudden increases in heating needs, driving up both feeding stock costs for generation (natural gas) and electricity prices[13].

Figure 23. Evolution of monthly average wholesale electricity prices in different European regions



Source: Platts, power exchange platforms

[13] See more detailed analysis in the Quarterly Report on European Electricity Markets: http://ec.europa.eu/energy/observatory/electricity/doc/20130814_q2_quarterly_report_on_european_electricity_markets.pdf

In 2010 and 2011 a slight recovery from the lows in 2009 could be observed for most of the regional power prices in Europe, however, in 2012 and 2013 prices were on a decreasing trajectory in most of the regions. On the demand side the sluggish economic recovery has put a lid on price increases, which could easily be tracked in limited industrial demand for power. After the 2008 crisis many industries did not cease to respond to high energy costs by further decreasing their electricity intensity, which might have also contributed to the lower power demand.

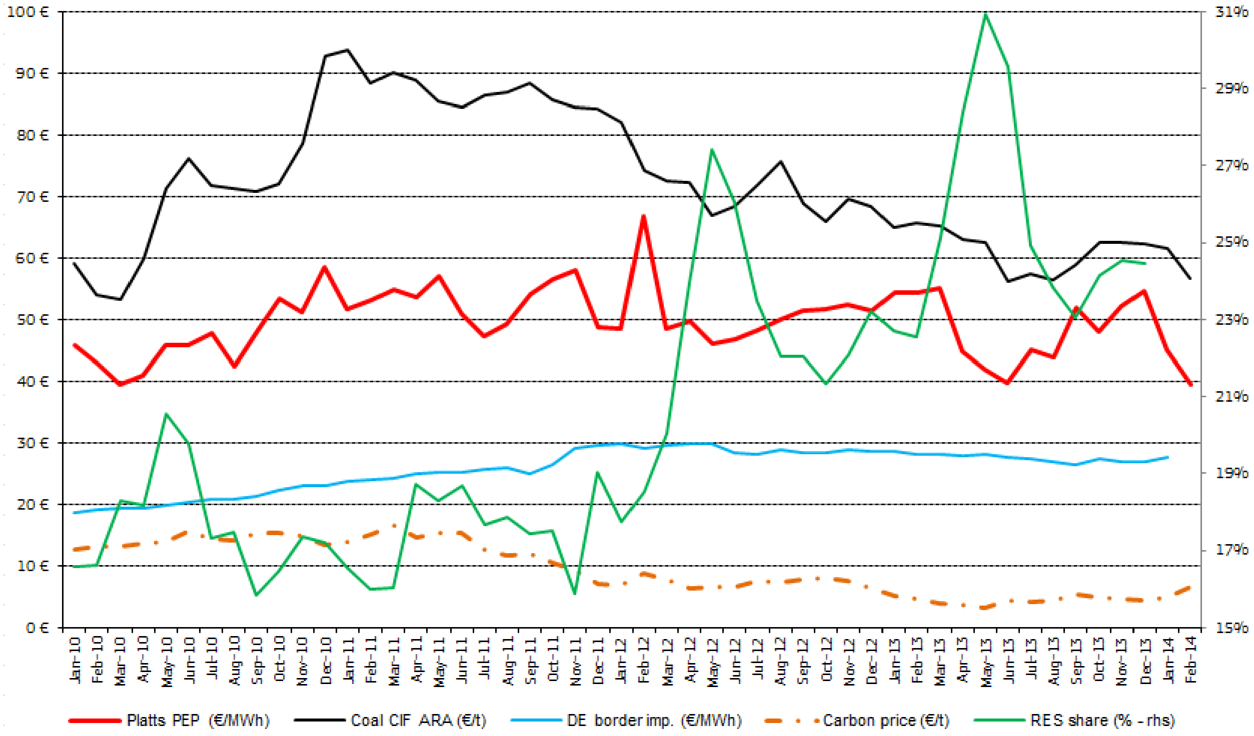
On the supply side several factors have simultaneously contributed to lower generation costs and have kept a lid on wholesale power prices, as **Figure 24** shows. Import coal prices in North Western Europe fell by 40% since the beginning of 2011, primarily owing to abundant import supply from Colombia and the United States. At the same time natural gas prices stabilised since the beginning of 2012 after a significant growth in 2010 and 2011. As oil-index gas contracts still have an important role in many EU countries and LNG shipments from third countries have substantially decreased since the first months of 2011 (LNG quantities have been sold on Asian markets, offering more competitive prices), natural gas prices have stuck on a relatively high level in Europe, despite the fact that industrial demand for gas remained limited during this period.

Decreasing coal prices, in contrast to relatively high gas prices, increased the profitability of coal-fired power generation to the detriment of natural gas. EU Emission Trading Scheme (ETS) emission allowance prices, reaching 15 €/tonnes of CO_2 equivalent in June 2011, fell below 5 €/tonnes in 2013 on average. The low carbon prices did not improve the situation of gas-fired generation either, as they could not incentivise gas-fired generation being proportionally less carbon-emission-intensive than coal.

These achievements have led to a gradual squeeze-out of natural gas; the share of this fuel fell by almost *five per cent* in the EU-28 power generation mix between 2010 and 2012, according to preliminary data from Eurostat[14]. At the same time renewable energy sources (solar and wind combined with significant hydro contribution in rainy periods) managed to gain ground, similarly to coal. The share of nuclear energy also diminished as a consequence of decisions in some member states to gradually abandon nuclear power generation in the forthcoming decade. As renewable power generation, due to its intermittent nature, needs backup capacities, the shift from less emission-intensive generation sources to coal raises a new challenge for national and European greenhouse gas emission reduction policies.

[14] See Chapter x on page y

Figure 24. Evolution of the Platts' Pan European Power index, the import price of the steam coal, German import border price for natural gas, emission allowance price and the share of renewables in the EU power generation mix



Source: Platts, BAFA

Platts PEP: Pan European Power Index (in €/MWh)

Coal CIF ARA: Principal coal import price benchmark in North Western Europe (in €/Mt)

DE border imp. stands for long term contract based import natural gas price on the German border (in €/MWh)

RES includes hydro, wind, solar and biomass; RES share in the total power generation estimation is based on monthly ENTSO-E data for the EU-28 as a whole

Traded volume and liquidity in the European wholesale markets

Besides the evolution of the price level it is important to analyse the traded volumes of power and the liquidity in the European wholesale electricity markets. Traded volume of power measures the amount of day-ahead baseload power contracts in a given period (e.g.: a quarter). Liquidity is defined as the ratio of traded volume of power and the gross inland electricity consumption in a given country or a region.

Figure 25 shows the quarterly evolution of traded volume of power and the European average liquidity between 2010 and 2013 for most of the European power trading markets. The highest traded volume of power could have been observed in this period in the Central Western European[15] (CWE) markets and in the Nordic markets[16] (Nordpoolspot). Nordpoolspot has also been the most liquid market, with a liquidity ratio of 96% in the fourth quarter of 2013, being above 80% during most of 2012 and 2013. The CWE region could also be found among the liquid ones, with a ratio of 34% in the fourth quarter of 2013. Power

[15] Germany, France, Belgium, Netherlands Austria and Luxembourg

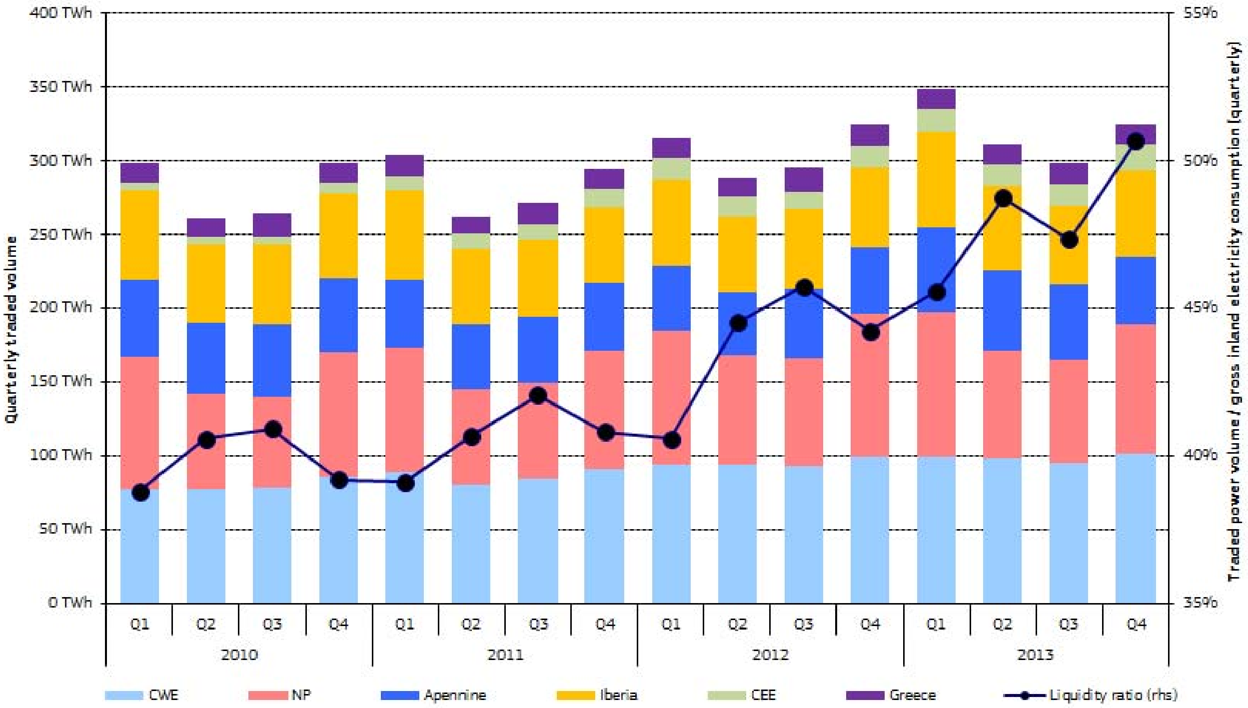
[16] Sweden, Denmark, Finland, Estonia, Latvia, Lithuania and Norway

regions, such as the Iberian-peninsula,[17] Apennine-peninsula (Italy) and Greece had high traded volumes and liquidity ratios as measured against the gross inland electricity consumption, however, these markets are so-called mandatory pools, meaning that all bilateral power trade must compulsorily be carried out on these trading platforms, resulting in traded volumes being higher than in other (non-mandatory) markets.

The Central and Eastern European[18] (CEE) region has been the most dynamically evolving region in the observed period, as traded volumes have nearly quadrupled and market liquidity has risen from 6.4% to 21.4%.

The overall European market liquidity, incorporating both mandatory and non-mandatory markets, rose from 39% to 51% between the first quarter of 2010 and the fourth quarter of 2013. Besides increasing traded in power volume this increase in the market liquidity was also due to decreasing gross inland electricity consumption in this four year long time period.

Figure 25. Evolution of quarterly traded volume of power in the major European regions and the average European power market liquidity



Integration of the European electricity markets

During the last decade several market couplings have taken place among neighbouring European markets, enabling an implicit cross border trade of electricity. The coupling of the Nordic markets already started at the beginning of the last decade and in June 2013, as the last

[17] Spain and Portugal

[18] Poland, Czech Republic, Slovakia, Hungary, Slovenia, Romania

country, Latvia became the part of the coupled region. In the Central Western European (CWE) region a trilateral coupling between France, Belgium and the Netherlands was introduced in 2006, which was extended to Germany in November 2010. In Central and Eastern Europe (CEE) a market coupling exists between the Czech Republic and Slovakia since 2009, which was extended to Hungary in September 2012. Poland is also coupled with Sweden and Slovenia with Italy as from the end of 2010.

Finally, at the beginning of February 2014 the CWE and the Nordic region was coupled with the UK and Ireland, forming the North Western Europe (NWE) market, with the participation of fifteen European countries. Since May 2014, also the South-West European Market, i.e. Spain and Portugal, are coupled with North-Western Europe.

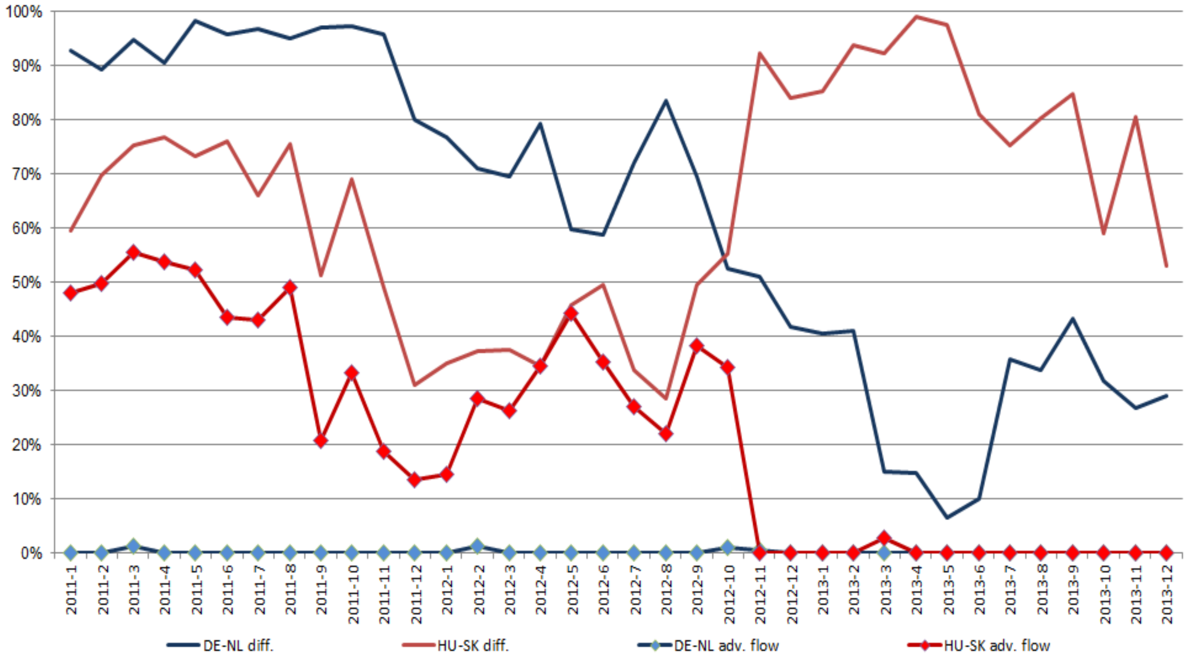
These market couplings have also contributed to the convergence in wholesale prices between neighbouring markets. However, the existence of market couplings does not necessarily eliminate price differentials. For example, the Dutch wholesale power prices had an average premium of 14 €/MWh to Germany in 2013, primarily owing to the significant impact of costly gas-fired generation in the Netherlands and to the lack of sufficient import capacities from Germany during the time of abundant solar and wind generation in that country. Belgian prices also decoupled from the other markets of the CWE region in 2012 and in the first half of 2013, as two nuclear reactors were permanently taken offline. Latvia and Lithuania still had a significant premium to other countries of the Nordic region, in the consequence of insufficient interconnections to other Nordpool markets and heavy dependence on electricity imports from Russia. Hungarian power prices, being coupled with the Czech and the Slovak markets, also showed signs of temporary decoupling many times in 2013, especially in the case of suddenly increasing domestic electricity consumption or significant amount of exports to the Balkans.

Nevertheless, market couplings contributed to the reduction of the number of occurrences of adverse power flows (when power is flowing from a more expensive market to a cheaper one, providing an example for non-economical behaviour), thus minimising welfare losses of cross-border power trade. In most of the cases the ratios of adverse powers compared to the total number of trading hours fell close to zero shortly after the implementation of the market coupling and remained almost negligible even if significant price differentials could be observed between neighbouring markets.

Figure 26 shows a good example for the co-existence of price divergences and low adverse power flow ratios between neighbouring markets. In 2011 the ratio of trading hours, when the hourly price difference was less than 10% between Germany and the Netherlands was above 90%, while in 2013 this ratio dropped below 40% during most of the time. However, adverse power flows hardly occurred between the two markets in spite of the existence of obvious price divergences.

On the other hand, adverse power flows between Hungary and Slovakia became almost negligible after the implementation of the market coupling in the autumn of 2012. However, the price divergence still exists between the two markets, though it is less significant as it was beforehand.

Figure 26 Monthly ratios of hourly price considered as being convergent and monthly adverse power flow ratios between Germany and the Netherlands and between Hungary and Slovakia

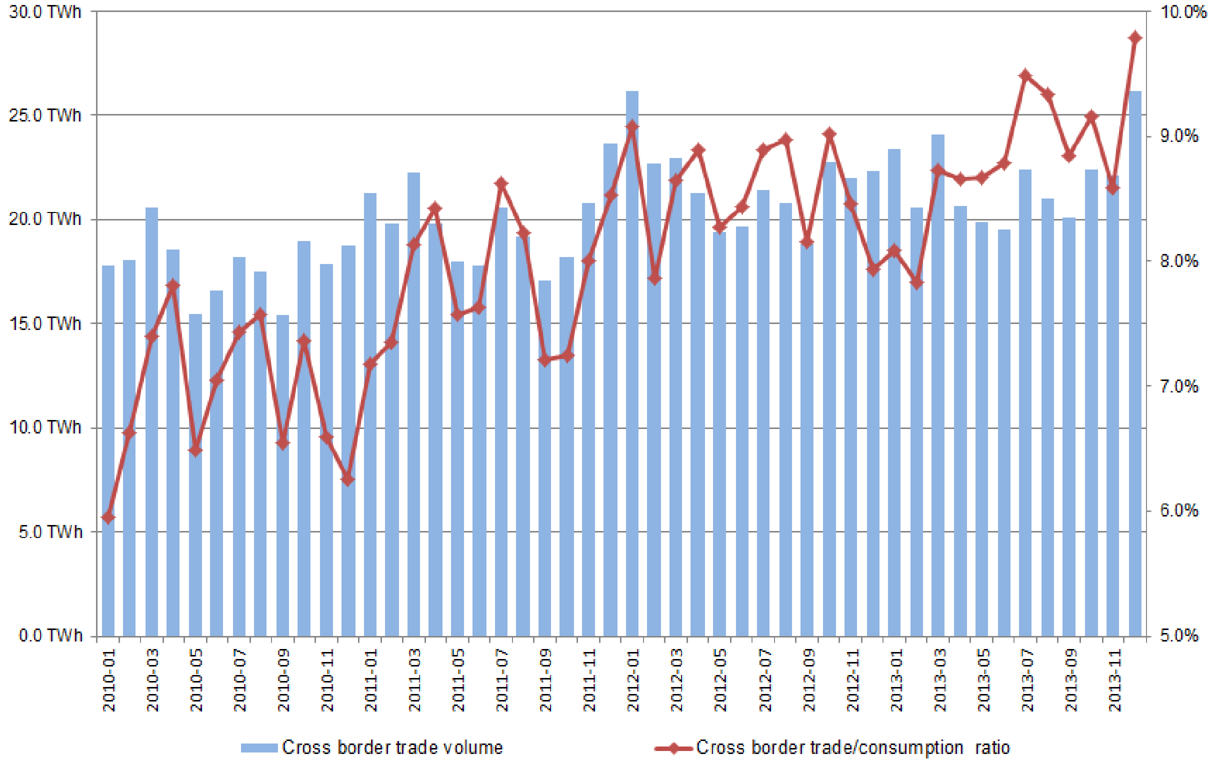


Source: HUPX, OTE-SK power exchanges

To put it in another way, market coupling can be a useful tool for promoting the integration of the European wholesale electricity markets within the course of the creation of a single internal electricity market, eliminating welfare losses from cross-border power trade, however, coupled markets do not necessarily lead to permanent price convergence in electricity prices across the coupled area. In order to improve convergence in prices, the development of physical power transmission and interconnector infrastructure is indispensable besides the existence of cross border trading allocation mechanisms.

Besides price convergence and adverse power flows between neighbouring power areas the integration of the European electricity markets can also be captured in increasing cross border electricity flows, as **Figure 27** shows.

Figure 27 Monthly cross border electricity flows in the EU and the ratio of cross border flows compared to the gross inland electricity consumption



Source: ENTSO-E

In 2010 the monthly average cross border electricity trade was 17.8 TWh in the EU, while in 2013 it amounted to 21.7 TWh, showing a growth of 23% in this period. Although monthly cross border trade volumes showed a high degree of seasonality between 2010 and 2013 (being higher in winter months, as electricity need increases, and lower during the summer periods), an upward trend in monthly trade volumes could clerarly be observed.

During the same time gross inland electricity consumption in the EU showed only a modest increase (being less than 2%). Dynamic growth in cross border trade as opposed to modest increase in electricity consumption resulted in an increase in the ratio of electricity cross border trade volumes compared to consumption, up from 6% measured in January 2010 to 9.8% in December 2013.

The increasing trend of cross border trade vlolumes compared to national electricity consumption clearly shows the good signs of the integration of European wholesale electricity markets, as the increasing availability of electricity sources from other markets helps in promoting competition and boosting consumer welfare.