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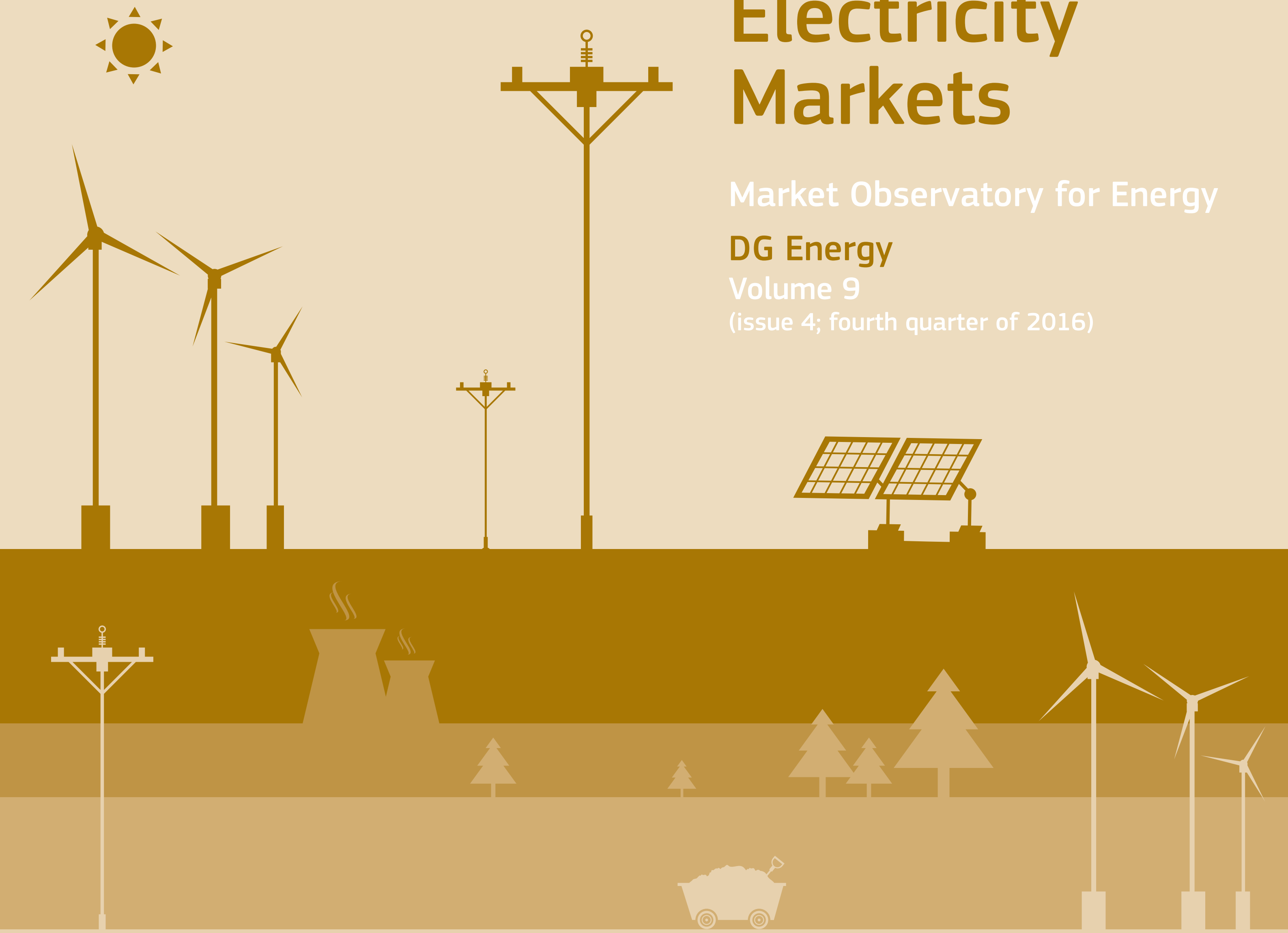

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Content

Highlights of the report

- In the fourth quarter of 2016 wholesale electricity prices in the EU increased measurably compared to the previous quarter, and reached 55 €/MWh on average, which was significantly higher than the 35€/MWh measured in the first three quarters of 2016 on average.

- Coal prices rose by 50%, from 60 €/Mt to 90 €/Mt over the fourth quarter of 2016, mainly in the consequence of increasing demand for imports in the Asian markets, impacting the international coal trade. Natural gas prices also rose in Q4 2016, resulting in increasing power generation costs.

- Significantly increasing coal prices made gas fired generation more competitive, even amid low carbon emission prices, which resulted in increasing gas deliveries to power plants and increasing share of natural gas in the European generation mix.

- Nuclear safety tests in France that started in the summer of 2016 continued in the fourth quarter of 2016, reducing by a third the availability of nuclear generation facilities, which gave a boost to wholesale electricity prices in Central and Western Europe.

- In the consequence of low nuclear availability in France and Belgium, prices diverged within Central and Western Europe, and in December 2016 France became a net electricity importer. The French wholesale price was so high in this month that even Italy showed a discount on monthly average, which was last seen in October 2009.

- In most of the European markets hydro based electricity generation in Q4 2016 was lower than the seasonal average, also providing an upward pressure on wholesale electricity prices.

- In 2016 wind power assured for the first time more than 10% of the whole European power generation mix, however, there were some weeks, (e.g.: mid-November 2016) when the share of wind was more than 15%.

Executive summary

- **Electricity consumption in the EU decreased by 0.5 % in August-October 2016 compared to the same period of 2015, while in January-October 2016 electricity consumption went down by 0.2% in year-on year comparison.** Economic growth in the EU-28 continued and GDP was up by 1.8% in year-on year comparison in the fourth quarter of 2016, while in the third quarter of the year GDP was up by 1.9%. Given that electricity consumption did not increase in parallel with the GDP, energy intensity of the EU economy followed the decreasing trend of the previous quarters.

- **The Platts' European Power Index (PEP),** expressing the average evolution of the wholesale electricity prices in the European markets, rose significantly during the fourth quarter of 2016, and it reached 55 €/MWh on average, being measurably higher than the average price of the first three quarters of 2016 (35 €/MWh). In Q4 2016 the PEP European benchmark wholesale price index was the highest since the first quarter of 2013.

- **Since the beginning of Q4 2016 coal import prices in the EU showed a significant increase,** as international coal trade was highly affected by decreasing domestic production in China, which resulted in additional demand on the global coal market. As on the short run coal supply could not keep pace with the increasing demand, coal prices reached 90 €/Mt by the end of 2016, which was significantly higher than 40 €/Mt measured in the first half of 2016 or than 60 €/Mt at the end of Q3 2016. In the fourth quarter of 2016 natural gas prices also increased ahead of the winter, with less LNG imports in North-Western Europe.

- **In the fourth quarter of 2016 gas-fired generation further improved its competitiveness vis-à-vis coal,** as rapidly increasing coal prices favoured gas, even amid low carbon prices. By the end of 2016 gas-fired power generation in the EU as a whole was higher than at the beginning of 2010, at the same time electricity generated from coal decreased by 30% compared to the end of 2013.

- In France and Belgium nuclear safety tests started during the summer of 2016, which were still ongoing during much of the fourth quarter of 2016, **resulting in a significant reduction in available nuclear generation capacities in Central and Western Europe.** In October 2016 around one third of the total installed capacities (21 out of 58 nuclear reactors) were offline in France. Unavailable nuclear capacities were partly substituted by natural gas-fired plants, which through increasing generation costs resulted in higher wholesale market prices, especially in France and Belgium. The Central Western Europe region decreased its electricity exports to the neighbouring markets, and France became a net electricity importer in December 2016. In the UK, primarily owing to interconnection capacity reductions with the continent, wholesale prices retained their significant premium to continental Europe.

- **Wind energy assured for the first time more than 10% of the EU power mix in 2016,** but during a week in mid-November 2016 the share of wind was higher than 15% in the whole EU generation mix. The fourth quarter of 2016 was drier than usual in many European countries, implying a decreasing share of hydro based generation in the EU electricity mix.

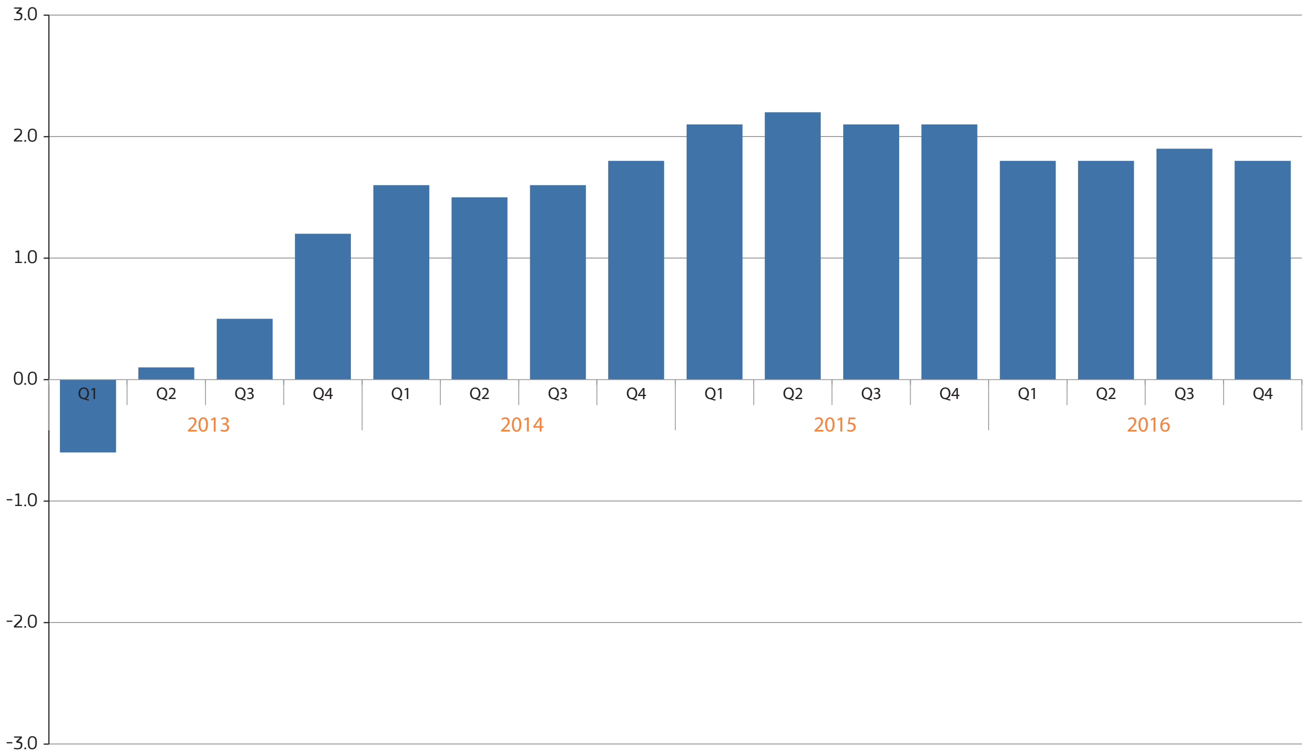
- **In January 2017 retail electricity prices for household customers decreased in the majority of the EU capital cities compared to January 2016,** mainly driven by decreasing energy and supply costs. This reflects that **recent increases in wholesale electricity prices did not appear yet in the final consumer bills.** Looking at retail prices for household and industrial customers, the same can be observed, as at the end of 2016 retail prices in most of the countries were lower than a year before.

1. Electricity demand drivers

As Figure 1 shows, economic growth in the EU-28 continued in the fourth quarter of 2016, and GDP grew by 1.8% in year-on-year comparison, similarly to Q3 2016 (1.9%) and Q2 2016 (1.8%).

Electricity consumption in the EU-28 decreased by 0.5% (3.5TWh) in the August-October of 2016 compared to the same period of the previous year. In January-October 2016 electricity consumption decreased by 0.2% compared to the same period of 2015. Similarly to the previous quarters, in this period the change in EU electricity consumption, compared to the economic growth, suggested that electricity intensity of the EU economy kept on improving.

FIGURE 1 – EU 28 GDP Q/Q-4 CHANGE (%)

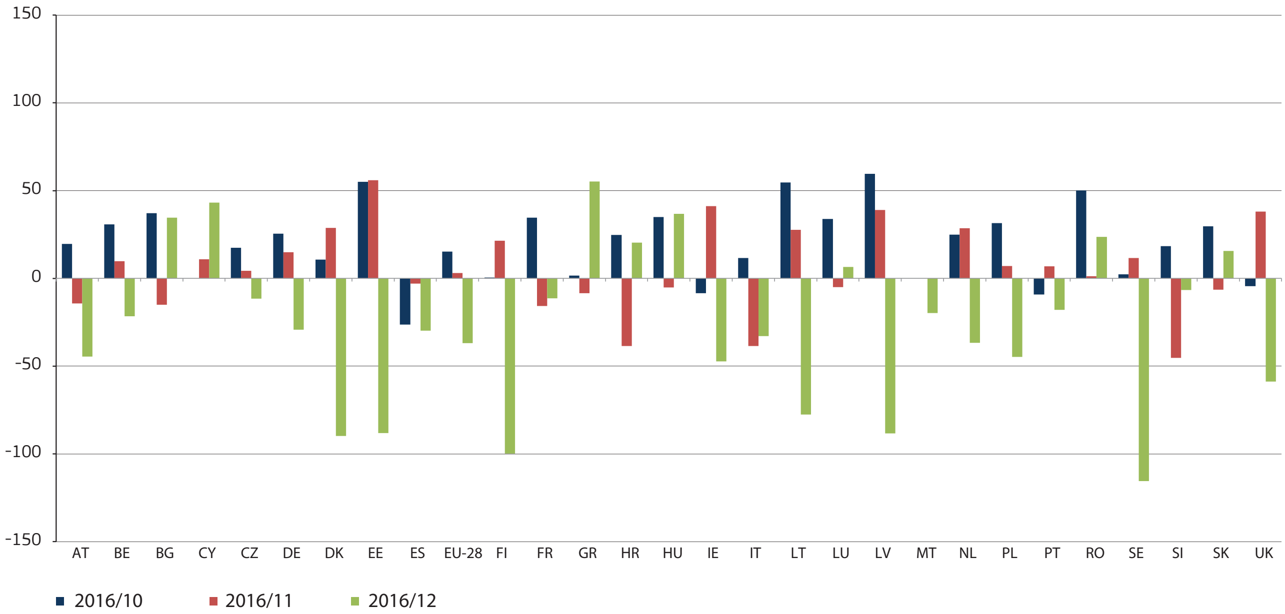


Source: Eurostat

- Figure 2 shows the monthly deviation of actual Heating Degree Days (HDDs) from the long term averages in October – December 2016 in the twenty-eight Member States of the EU. In most of the EU October 2016 was colder than usual, implying higher heating degree day values than the long term average. In some regional markets (See in Chapter 4), the cold weather impacted the wholesale electricity market, especially in those countries where electricity has an important role in residential heating.

- In contrast, December 2016 was milder than usual in most of Europe, though in some countries of Central and South-eastern Europe temperatures were lower than usual. Milder weather conditions, coupled with lower demand for electricity at the end of the year, resulted in decreasing wholesale electricity prices in many European markets.

FIGURE 2 - DEVIATION OF ACTUAL HEATING DEGREE DAYS (HDDS) FROM THE LONG TERM AVERAGE, IN OCTOBER-DECEMBER 2016



Source: Eurostat/JRC.
The colder is the weather, the higher is the number of HDDs

2. Evolution of commodity and power prices

2.1 Evolution of power prices, and the main factors affecting power generation costs

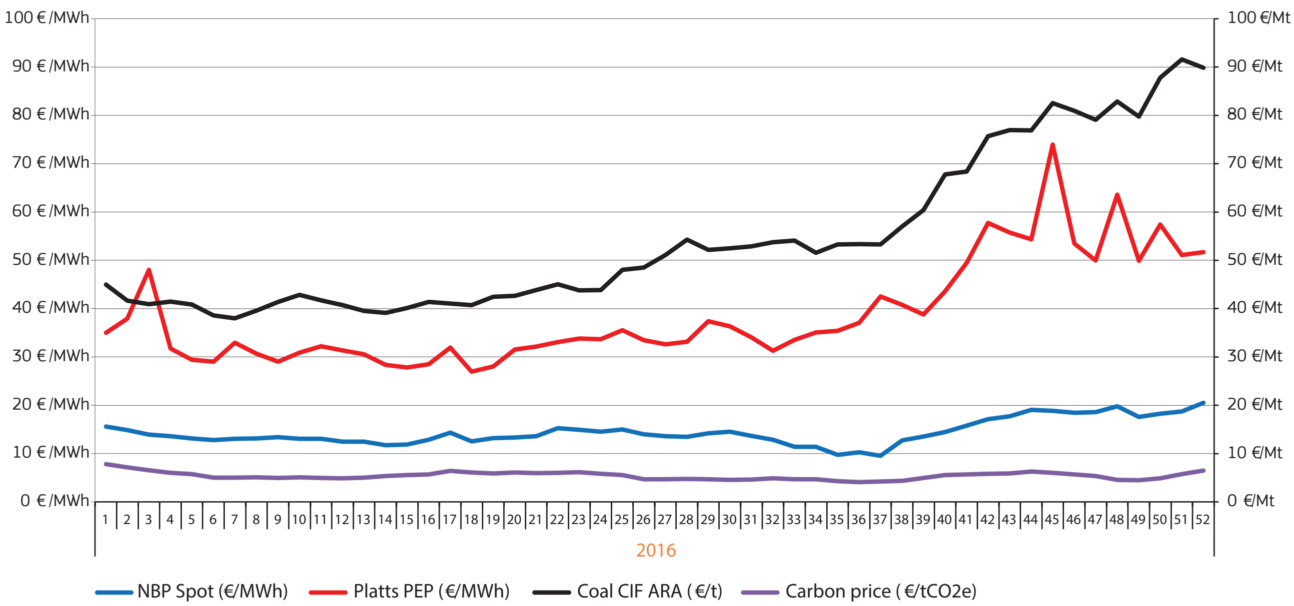
- Coal prices (as represented by CIF ARA contracts, an import price benchmark widely used in North-Western Europe), as Figure 3 shows, underwent a significant increase in the fourth quarter of 2016: while at the end of September the coal contract stood at 60 €/Mt, by the end of the year it reached 90 €/Mt, being the highest since April 2011. This sharp increase could mainly be explained by the increasing demand in the Asian markets, as China opted for replacing domestic coal production with imports. As supply on the international coal markets (increase in production capacities) could not keep pace with the increasing demand on the short run, prices started to increase.

- Furthermore, in Europe coal started to play a more intensive role in electricity security of supply, as singificany nuclear generation capacities were taken offline ahead of the winter season. This has given a further support to import coal prices in North-Western Europe.

- Natural gas prices (represented by the most liquid hub prices in North-Western Europe) also showed an increasing trend in the fourth quarter of 2016. A number of factors contributed to the price increase, including the relatively cold weather at the start of the gas year in October (especially when compared with the previous year), low LNG imports in North-Western Europe, strong demand in the power sector, also relating to the aforementioned capacity reduction in nuclear power generation.

- The price evolution of coal and gas resulted in increasing wholesale electricity prices on the market, as these two fuels typically set the marginal costs of electricity generation in Europe. Therefore, wholesale electricity prices (represented here by the Platts PEP index as a European benchmark[1]) increased significantly in the fourth quarter of 2016, reaching 55 €/MWh on average, which is was the highest since Q1 2013 and represented a measuable change compared to the average of 35 €/MWh in the first three quarters of 2016.

FIGURE 3 - WEEKLY EVOLUTION OF EUROPEAN AVERAGE WHOLESALE POWER PRICES COMPARED WITH COAL AND GAS PRICES

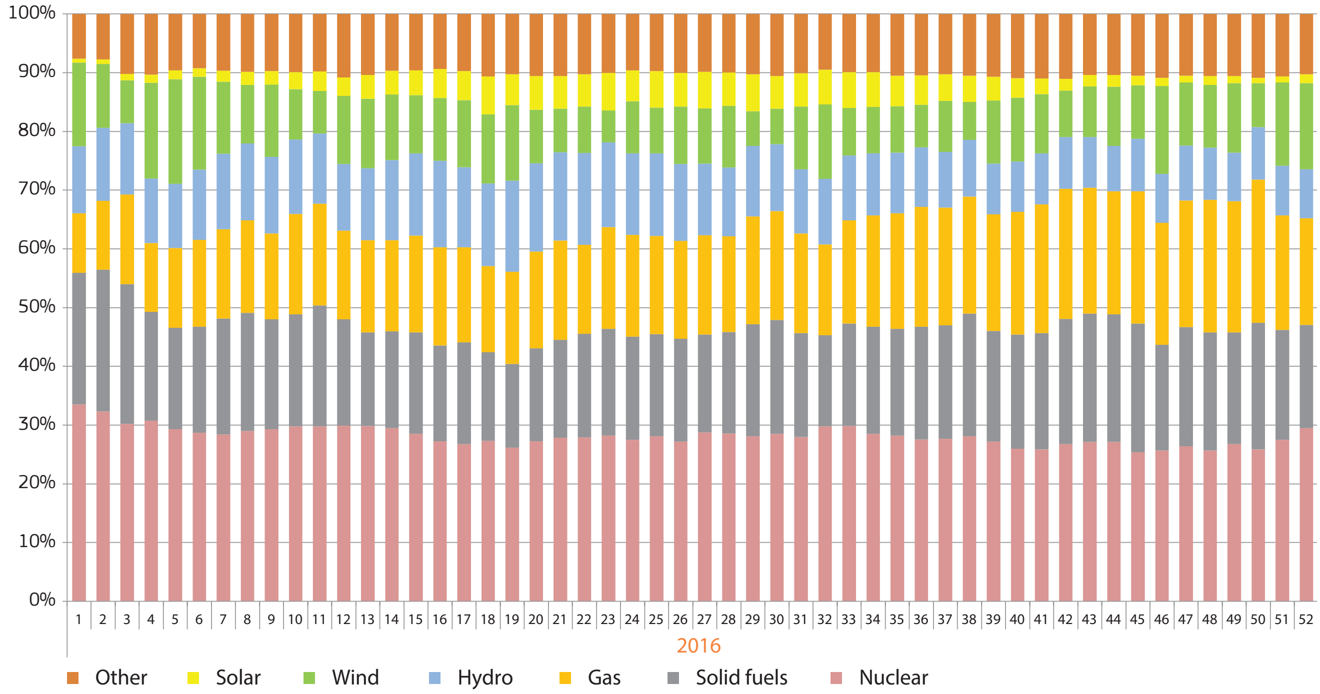


Source: Platts,
Platts PEP: Pan European Power Index (in €/MWh) Coal CIF ARA: Principal coal import price benchmark in North Western Europe (in €/Mt)
NBP spot stands for the National Balancing Point (UK) gas spot price (in €/MWh) Carbon price: EUA emission allowance spot pirce, in €/t

- Figure 4 shows the weekly evolution of the electricity generation mix in 2016 in the EU-28. Throughout the weeks of 2016 nuclear had a fairly stable share in the EU generation mix, although at the end of the year its importance decreased, as in Central and Western Europe significant capacities were taken offline (See Chapter 4.1). In the second half of 2016 the share of natural gas increased in the EU power generation, as in paralel with sharply increasing coal prices the relative competitiveness of gas improved, even amid low CO_2 emission prices. Natural gas increased its share in the EU power mix mainly to the detriment of coal and lignite fired electrcity generation.

- The second half of 2016 was drier than usual in many Euroean countries; implying a decreasing share of hydro based electricity generation. On average, wind power generation represented 10% of the EU electricity mix in 2016, however, in some weekly periods (e.g.: mid-November 2016) its share reached 15%. In some markets wind tends to more and more function as baseload electricity generation source. Solar power generation shows a strong seasonality; during the summer months of 2016 its share reached 5-6% in the European generation mix.

FIGURE 4 - WEEKLY EVOLUTION OF THE ELECTRICITY GENERATION MIX IN THE EU-28



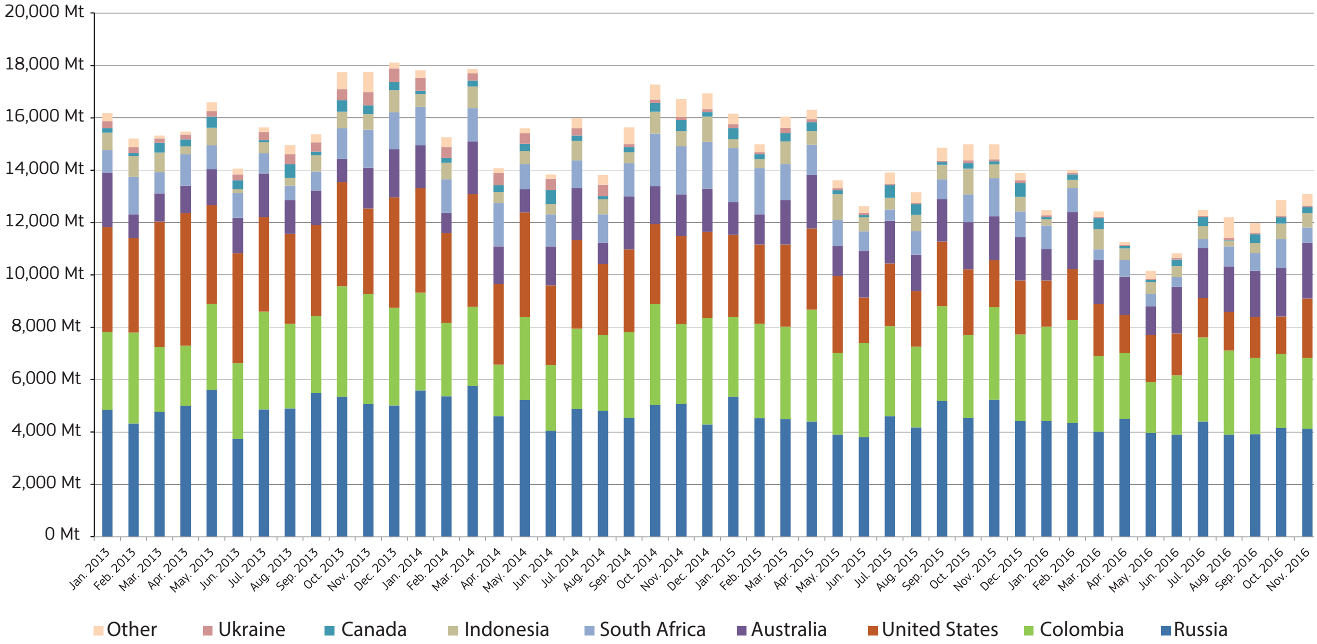
Source: ENTSO-E

- Figure 5 shows the major extra-EU coal import sources and the monthly amount of imported coal in the EU. Although in the second half of 2016 coal imports in the EU started to pick up, it must have been rather due to seasonal behaviour (increasing coal needs ahead of the winter season) that the beginning of a new trend. In September-November 2016 extra-EU coal imports in the EU-28 were down by a quarter compared to the same period of 2013, reflecting amongst others the decreasing share of coal in power generation.

- In September-November 2016 the largest chunk of extra EU coal imports came from Russia, with a share of 32% in the total, followed by Colombia (22%). In 2016 Australia overtook the United States in the EU coal imports (their share were respectively 15% and 14%). The share of South Africa in the total extra-EU imports was 6% in September-November, while the shares of Indonesia, Canada, Ukraine and other sources remained below 4% each.

1. At the end of December 2016 Platts discontinued publishing the PEP benchmark index, as from the next edition of the quarterly electricity report another benchmark index will be referred to

FIGURE 5 – THE MOST IMPORTANT EXTRA-EU COAL IMPORT SOURCES AND QUARTERLY IMPORTED QUANTITY IN THE EU-28



Source: Eurostat, COMEXT database

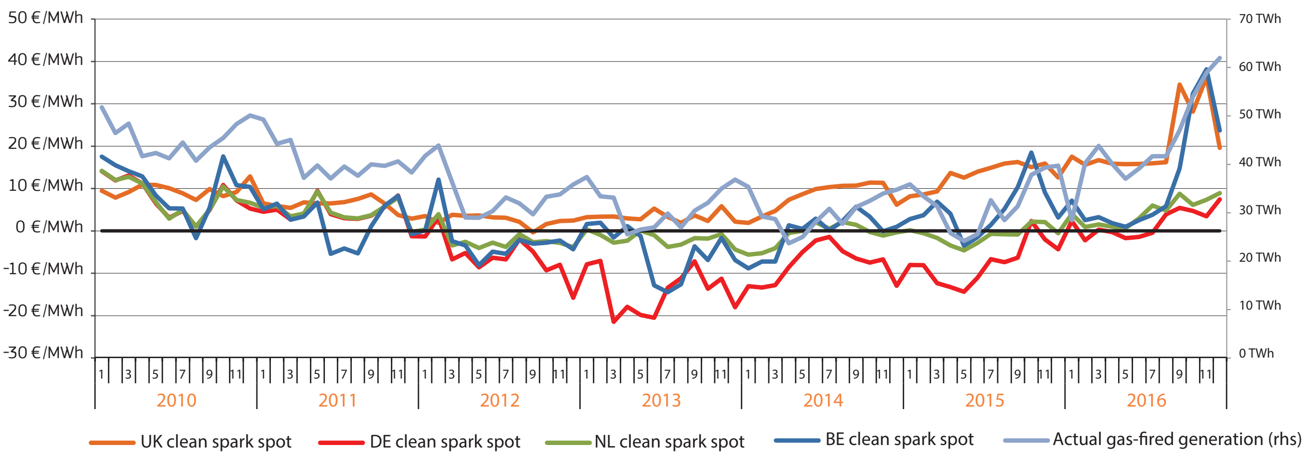
- In the fourth quarter of 2016 clean spark spreads remained in the positive range on all major European electricity markets, implying profitability of gas fired generation in Europe. Although gas prices rose measurably during Q4 2016, higher electrcity prices offset the increase in generation costs. In the consequence of improving profitablity and temporary reduction in nuclear capacities in a few European countries, gas-fired generation in the EU-28 reached by the end of 2016 the highest since 2010, as presented on Figure 6.

- Clean spreads only include the impact of emission allowances and do not include national measures penalising high emissions from power generation (e.g.: carbon tax in the UK, affecting coal-fired generation more than natural gas), implying that these metrics might underestimate the competitiveness of gas-fired generation vis-à-vis coal. As of April 2014, the time of the introduction of the carbon tax in the UK, a clean dark spread metric taking into account of the tax impact is also computed for the British market, as Figure 7 shows. Therefore after April 2014 only the new clean dark spread is shown on the figure.

- In Germany the profitability of coal-fired generation remained close to zero over the last two-three years, while in the UK the carbon tax corrected metrics turned to negative in 2016, resulting in rapid decrease of the share of coal in the UK power mix (See Chapter 4.2). At the end of 2016 it temporarily picked up again, due to high wholesale electricity prices in the UK.

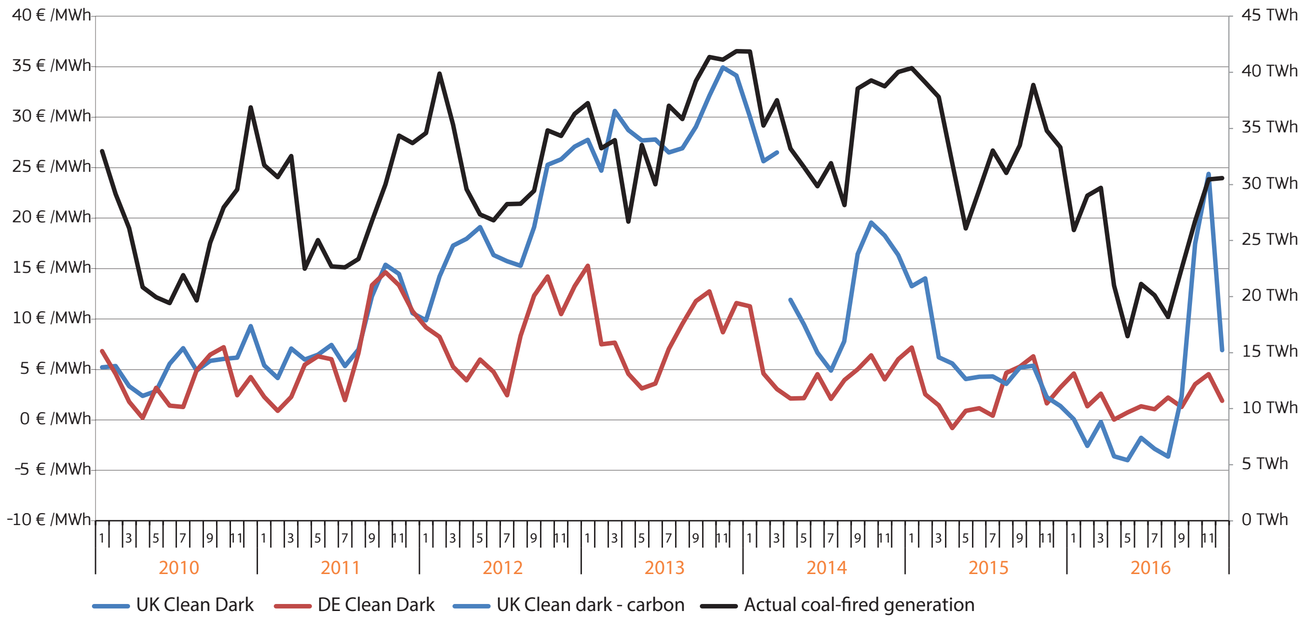
- During the last six years coal fired generation peaked at the end of 2013 in the EU, and since then, showing a high degree of seasonality, it decreased by 30% by the end of 2016.

FIGURE 6 – EVOLUTION OF CLEAN SPARK SREADS IN SELECTED MARKETS AND ELECTRICITY GENERATION FROM NATURAL GAS IN THE EU



Source: Platts and ENTSO-E Data are not available for Malta

FIGURE 7 – EVOLUTION OF CLEAN DARK SREADS IN SELECTED MARKETS AND ELECTRICITY GENERATION FROM COAL IN THE EU



Source: Platts and ENTSO-E Data are not available for Malta

2.2 Comparisons of monthly electricity baseload prices on electricity markets

- As the next map (Figure 8) shows, there were significant price differences in the wholesale electricity prices across the EU. More details on the drivers behind price changes in each market can be found in Chapter 4.

- In the fourth quarter of 2016 wholesale baseload electricity prices reached the highest since the first quarter of 2013 on EU average. The most expensive countries, regarding the average day-ahead wholesale electricity price, were the United Kingdom (66 €/MWh), France (60 €/MWh), Belgium (58 €/MWh) and Spain (57 €/MWh). On the other hand, the cheapest market was Denmark (35 €/MWh) and the quarterly average wholesale electricity price was around 37-38 €/MWh in Sweden, the three Baltic States, Germany and Poland.

- Compared to Q3 2016, in the fourth quarter of 2016 wholesale electricity prices increased by the most in France (85%) and Belgium (78%). Prices were up by 61% in Sweden, by 48% in France and by 45% in Denmark in year-on-year comparison. In Latvia and Lithuania prices went down by 19% and in Greece by 7% in the fourth quarter of 2016, if compared with the Q4 2015.

FIGURE 8 – COMPARISON OF AVERAGE WHOLESALE BASELOAD ELECTRICITY PRICES, FOURTH QUARTER OF 2016

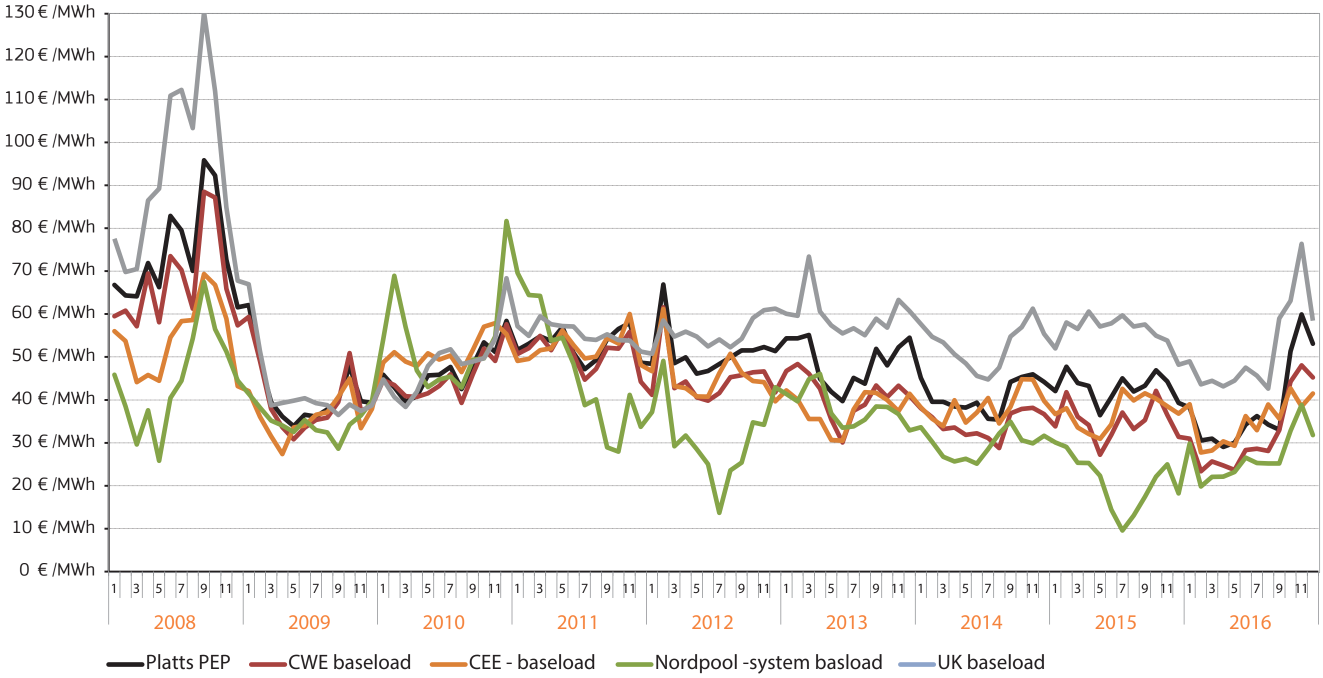
Source: European wholesale power exchanges

- Figure 9 and Figure 10 show the evolution of the monthly average baseload wholesale electricity prices in the main power regions in the EU since 2008; in parallel with the Platts European Power Index (PEP). In Q4 2016 the aforementioned generally increasing price trend in all European regions has resulted in monthly average prices reaching several year highs in few regions.

- The UK market, being the highest priced in all Europe, had a measurable premium to Central Western Europe[2] in Q4 2016 (21 €/MWh on average), which was largely due to the limited interconnector availability with the continental markets (See Chapter 4.2). The regional average price in Central Western and Central Eastern Europe[3] remained below the Platts PEP European benchmark, in spite of the price hikes due to significant generation capacity reductions in Western Europe. Meanwhile, prices in the Nordpoolspot[4] market were still lower than the PEP benchmark.

- Interestingly, in the fourth quarter of 2016 monthly wholesale electricity prices in Spain, Italy and Greece, presented on Figure 10, remained aligned with the PEP index, or were even below the benchmark, as in the southern EU countries the increase in wholesale electricity prices was smaller than the average.

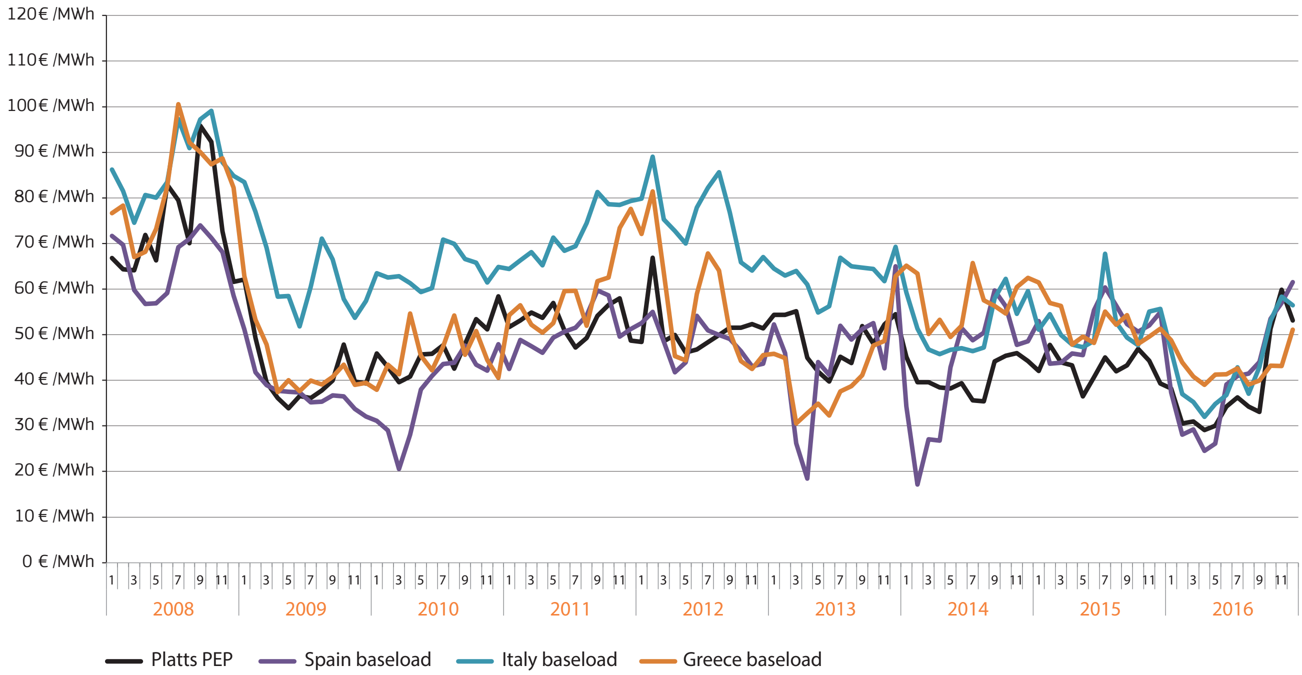
FIGURE 9 – COMPARISONS OF THE PLATTS PEP AND MONTHLY ELECTRICITY BASELOAD PRICES IN REGIONAL ELECTRICITY MARKETS (CWE, CEE, NORDPOOL AND THE UK)



Source: European wholesale power exchanges

2. Central Western Europe includes Austria, Belgium, France, Germany, the Netherlands and Switzerland
3. Central Eastern Europe includes Czech Republic, Hungary, Poland, Romania, Slovakia and Slovenia
4. Nordpoolspot includes Denmark, Estonia, Finland, Latvia, Lithuania, Norway and Sweden

FIGURE 10 – COMPARISONS OF THE PLATTS PEP AND MONTHLY ELECTRICITY BASELOAD PRICES IN REGIONAL ELECTRICITY MARKETS (SPAIN, ITALY AND GREECE)

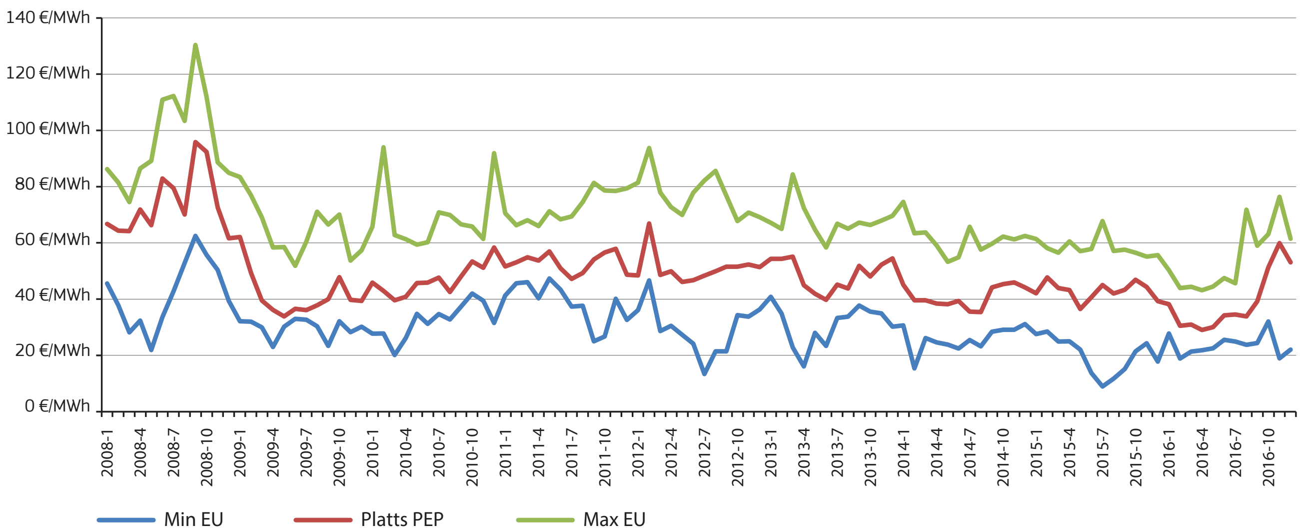


Source: Platts, European power exchanges

- In the consequence of these market developments, in the fourth quarter of 2016 the price gap between the cheapest and the most expensive European average regional price widened compared to Q3 2016 as it can be followed on Figure 11. However, as from November to December 2016 the average wholesale price in the most expensive market (UK) managed to decrease, the regional differences became smaller again. Higher average benchmark electricity prices tend to go hand in hand with higher regional differences.

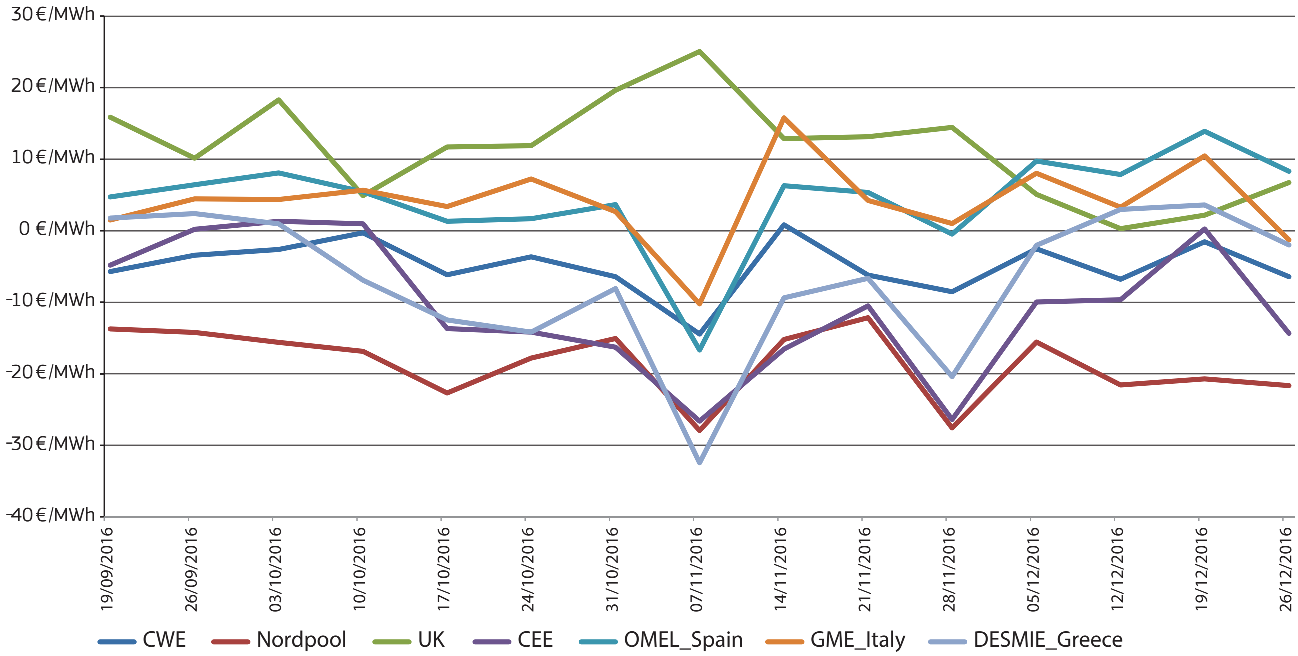
- Regional price differences are also reflected on Figure 12, showing the weekly evolution of regional price premiums or discounts to the PEP benchmark index in the fourth quarter of 2016. In Q4 2016 price fluctuations in the UK market managed to significantly impact the differential between the benchmark and the other European regions, as high prices in the UK had an increasing impact on the benchmark. With the exception of the UK, regional averages were either below the benchmark or in the case of Spain and Italy they were only slightly above during most of the time in Q4 2016.

FIGURE 11 – THE EVOLUTION OF THE LOWEST AND THE HIGHEST REGIONAL WHOLESALE ELECTRICITY PRICES IN THE EU AND THE PEP BENCHMARK



Source: European power exchanges, own computations. In Q2 and Q3 2016 the cheapest markets were Germany and Austria in the EU, while the highest wholesale electrcity prices could be observed in the UK. It is important to note that not only the price range, but the location of the cheapest and the most expensive markets within the EU might change over the timespan presented on this chart.
Source: Platts, European power exchanges

FIGURE 12 – DIFFERENCE BETWEEN THE PEP INDEX AND THE WEEKLY REGIONAL WHOLESALE ELECTRICITY PRICES



Source: Platts, European power exchanges, own computations

3. Traded volumes, market liquidity and cross border trade of electricity

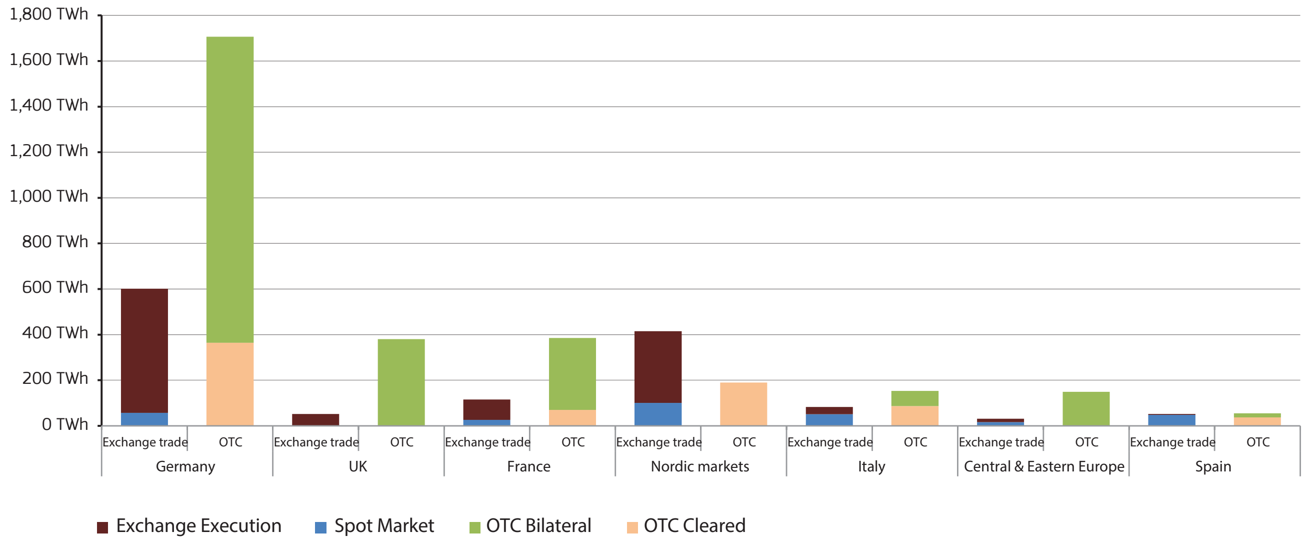
3.1 Comparison of wholesale market trading platforms and the over-the-counter (OTC) markets

- Figure 13 shows the comparison of volumes in different market segments in electricity trading on the most liquid electricity trading platforms in the EU. In order to show the significance of spot and forward traded volumes on organised trading platforms, as well as bilateral trade and cleared trade on the so-called over-the-counter (OTC) markets, two different columns represent on the chart the two types of electricity trade in each market.

- In year-on-year comparison the combined traded volume (market trade and OTC together) significantly increased in the fourth quarter of 2016 in the United Kingdom (54%), Germany (48%), France (21%) and the Nordic markets (18%), while in Italy it decreased by 27%. The year-on-year change in the OTC traded volume evolved similarly in these markets, except for France, where OTC trade grew by only 15% in comparison to the aforementioned increase in total trade volume (21%). Looking at the numbers showing the evolution of the traded volume of electricity compared to the previous quarter (Q3 2016), in the fourth quarter of the year all observed markets on Figure 13 showed significant increases (ranging from 20% to 92%), as in the fourth quarter of the year both electricity consumption and traded volumes normally rise at the beginning of the winter period.

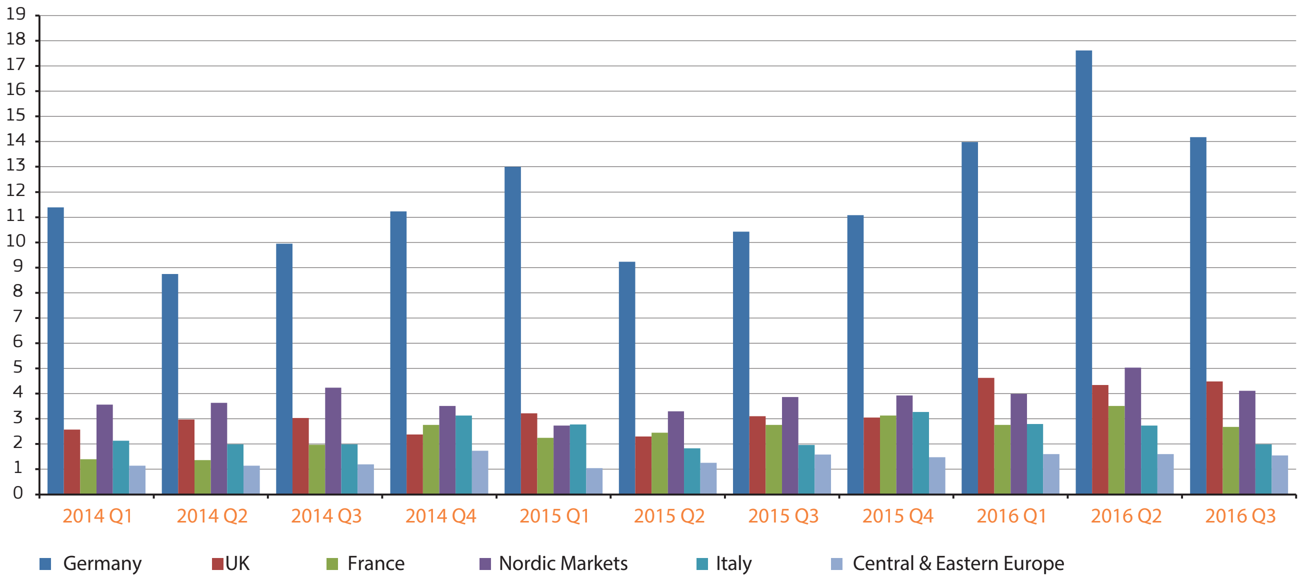
- Market liquidity can be measured by the so-called churn rates, providing information on the ratio of the total volume of power trade (including exchange executed and OTC markets) and electricity consumption in a given time period. Figure 14 shows the evolution of the quarterly regional churn rates between the beginning of 2014 until the third quarter of 2016. In the third quarter of 2016 all observed markets showed decreasing churn rates compared to Q2 2016, implying that trading liquidity decreased compared to the electricity actually consumed. However, if churn rates are compared to those in Q3 2015, the trading liquidity increased (or at least remained stable) in all markets. In Q3 2016 the most liquid market in Europe was Germany, reaching an outstanding churn rate of 14, followed by the UK (4.5) and the Nordic markets (4.1).

FIGURE 13 – COMPARISON OF ELECTRICITY TRADED VOLUMES IN SOME IMPORTANT DAY-AHEAD, FORWARD AND OTC MARKETS, FOURTH QUARTER OF 2016



Source: Platts, wholesale power markets, Trayport, London Energy Brokers Association (LEBA) and own computations

FIGURE 14 – QUARTERLY CHURN RATES ON SELECTED EUROPEAN WHOLESALE ELECTRICITY MARKETS



Source: Trayport, London Energy Brokers Association (LEBA), ENTSO-E and own computations

3.2 Cross border trade of electricity

- As Figure 15 shows, in the fourth quarter of 2016 the Central Western Europe (CWE) power region continued to be in a strongly net electricity exporter position. However, in November-December 2016 its net electricity outflow position was the smallest since April 2013. Electricity exports to the British Isles, Italy and Central Eastern Europe from the region decreased compared to Q3 2016.

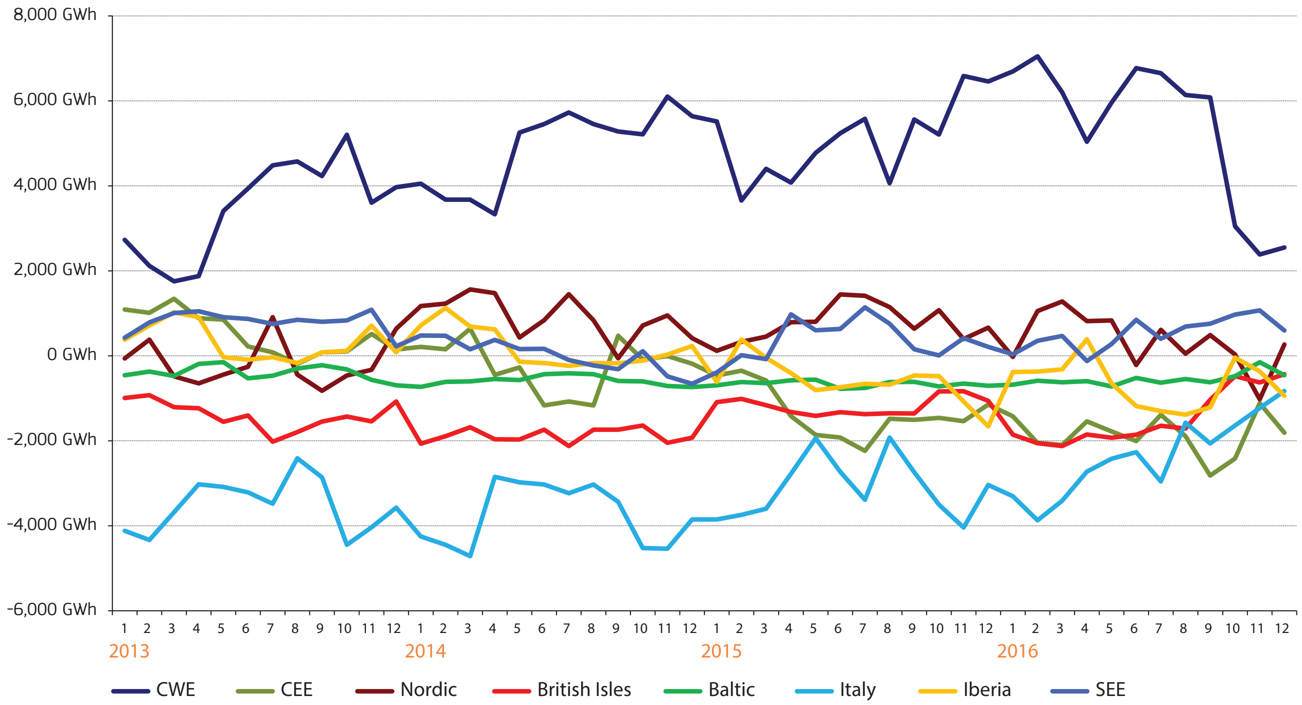
- In the fourth quarter of 2016 net electricity imports in Central Eastern Europe (CEE) decreased compared to the previous quarter. However, from South East Europe and from countries like Ukraine the amount of competitive electricity imports increased.

- In the UK net imports from continental Europe fell to several years' low in the consequence of interconnector capacity restrictions, though the significant wholesale electricity price differentials between the UK and the continent would have substantiated an increase in power inflow to the country.

- In Italy net imports did not follow the usual seasonal pattern of increase at the beginning of the winter season; instead the countries net importer position became smaller. High electricity prices in France resulted in decreasing power exports to Italy.

- The Nordic market, due to decreasing domestic hydro generation, could not export so much electricity to Central Western and Eastern Europe to avoid being net electricity importer, practically for the first time since the end of 2013.

FIGURE 15 – EU MONTHLY CROSS BORDER PHYSICAL FLOWS BY REGION



Source: ENTSO-E

European countries are grouped in the following regions:

Central Western Europe	*DE, NL, FR, LU, BE, AT, CH*	*Nordic*	*SE, FI, DK, NO*
Central Eastern Europe	*PL, CZ, HU, SK, HR, SI*	*British Isles*	*UK, IE*
Iberian-Peninsula	*ES, PT*	*Apennine Peninsula*	*IT*
South Eastern Europe	*RO, BG, GR, RS, BA, ME, FYROM, AL*	*Baltic*	*EE, LT, LV*

4. Regional wholesale electricity markets

4.1 Central Western Europe (Austria, Belgium, France, Germany, the Netherlands, Switzerland)

- Over the fourth quarter of 2016 wholesale electricity prices in the CWE region showed a significant increase: while in September 2016 the monthy average baseload price was 33 €/MWh and the monthly peakload average amounted to 36 €/MWh, by December 2016 they respecctively went up to 45 €/MWh and 53 €/MWh.,as Figure 16 shows. The monthly average baseload and peakload contracts reached their peak in November, being the highest monthly figure since February 2012.

- On the supply side of the wholesale market there were a number of factors contributing to this general price increase in the region. Coal prices showed a signficant rise (more than 50% between the beginning and the end of the fourth quarter of 2016 – See Chapter 2.1), similarly to natural gas prices in the North West European hubs. The consumption of coal and natural gas in power generation also increased in the region and given these two fuels typically set the marginal electricity generation costs, as result wholesale electricity prices also increased.

- As Figure 17 shows, there were clear signs of divergence between different markets in the CWE region: while in Germany and the Netherlands, though increasing measurably, daily average prices remained in lower ranges (30-50 €/MWh) during most of the time throughout Q4 2016, in France and Belgium wholesale prices rose sharply (above 100 €/MWh on daily average, several times in November) and proved to be much more volatile.

- The availability of nuclear generation capacities played an important role in the price increase in Q4 2016 in the region, especially in France and Belgium. Nuclear safety tests in France, already started in August 2016, have been extended several times in the following months and resulted in security of electricity supply concerns ahead of the winter season. In October 2016 in France around one third of the total installed capacities (21 out of 58 nuclear reactors) were offline. In Germany, due to the expiry of the nuclear fuel tax at the end of the year, an unprecendented winter refuelling schedule also contributed to lower generation capacity avialability, while in Switzerland reactor of 1.2 GW capacity (Leibstadt) was expected to remain offline until February 2017, also tightening supply margnis. In December 2016 however, supply constraints eased as significant capacites in France were expected to return to the grid, which mainly impacted wholesale prices on the curve.

- Figure 18 shows the share of nuclear generation in the domestic electricity consumption in four different countries of the region. In France nuclear capacities managed to assure more than 80% of the domestic electricity needs during the second half of 2015 (or in some periods this share was above 100%, implying a significant electricity export potential). However, in some periods in Q4 2016 the share of nuclear in domestic power needs fell below 70% in the country, resulting in significant import needs from its neighbours, which impacted wholesale electricity prices in all North Western Europe. In Decemeber 2016 France became a net electricity importer for the first time in five years. In Belgium rapdily changing availability of nuclear capacities substantially contributed to price volatility in the local wholesale market, while in Germany the share of nuclear energy also decreased during the last few weeks of 2016 due to the aforementioned refuelling schedule, stemming from tax policy implications.

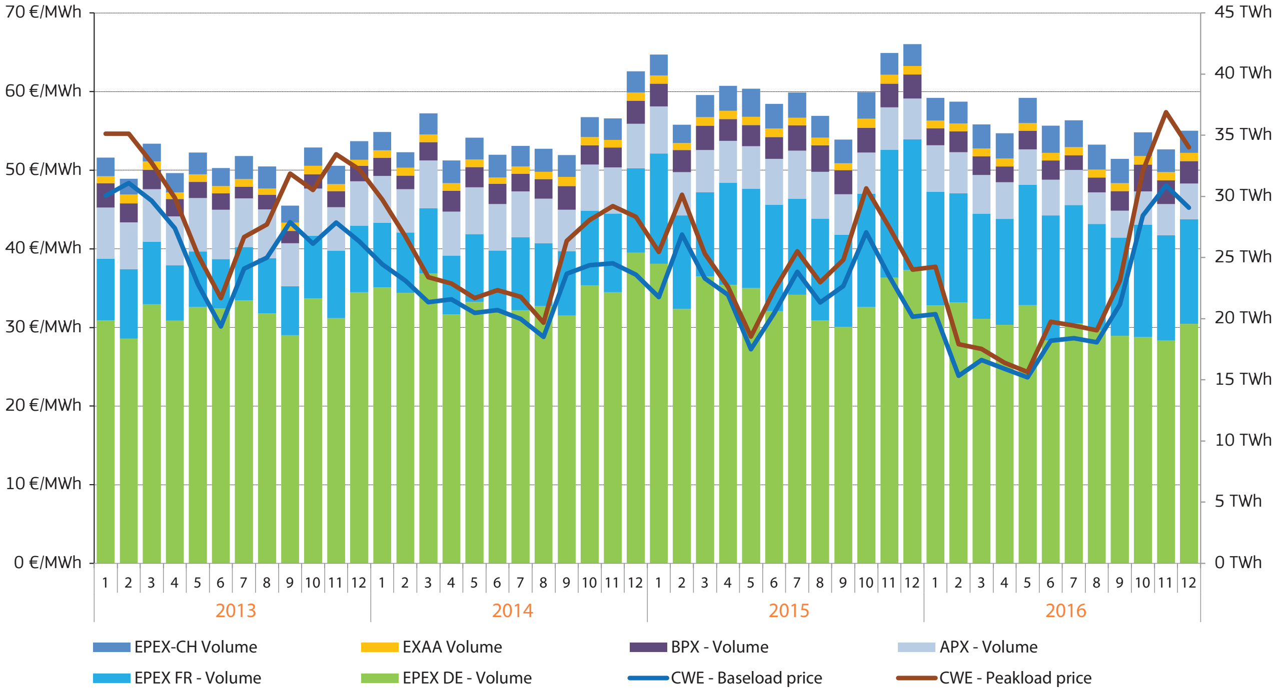
- In November-December 2016 electricity generation from wind in Germany was lower by a quarter compared to the last two months of 2015, also adding to the upward pressure on regional wholesale electricity prices as dwindling renewable and nuclear generation had to be substituted by increasing coal and gas fired generation, resulting in rising generation costs.

- A recent analysis prepared by the European Commission[5] shows that in Europe on average one per cent increase in the share of variable renewable sources in the electricity mix results in a decrease of 0.4 €/MWh in the wholesale price level, however, in the CWE region the impact of renewables is stronger (amounting to 0.6-0.8 €/MWh). The impact one per cent increase in the share of coal and gas fired generation results in a price increase of 0.2-1.3 €/MWh across Europe, with higher importance of natural gas in the CWE region.

5. See Chapter 1.1 on wholesale electricity markets in the 2016 report on Energy prices and costs in Europe: http://ec.europa.eu/energy/sites/ener/files/documents/swd2.pdf

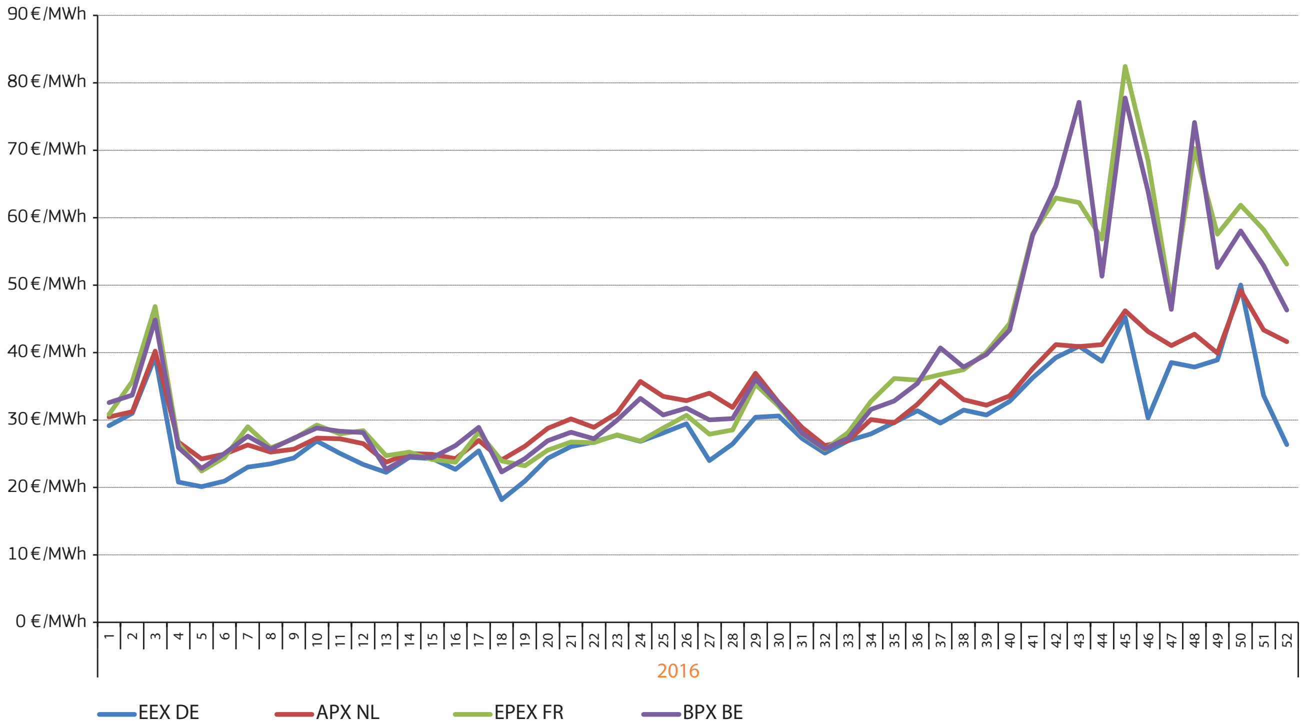
- On the demaind side of the market it is worth mentioning the lower-than-normal temperatures across the countries of the CWE region in October and November, including some short lived cold spells that impacted wholesale electricity prices, especially in France as electricity has an important role in domestic heating in that country. However, mild weather conditions in December 2016, and the dwindling industrial demand during the Christmas holiday season have led to negative market prices in Germany (on 26 December the daily average was -12 €/MWh) for the first time in this period of the year since 2013. Negative market prices signal that during periods of low demand for electricity high variable renewable generation, coupled with inflexible base-load generation technologies can lead to significant electricity oversupply, which calls for a better electricity market design and intergration of various generation sources in the power grid.

FIGURE 16 – MONTHLY TRADED VOLUMES AND PRICES IN CENTRAL WESTERN EUROPE



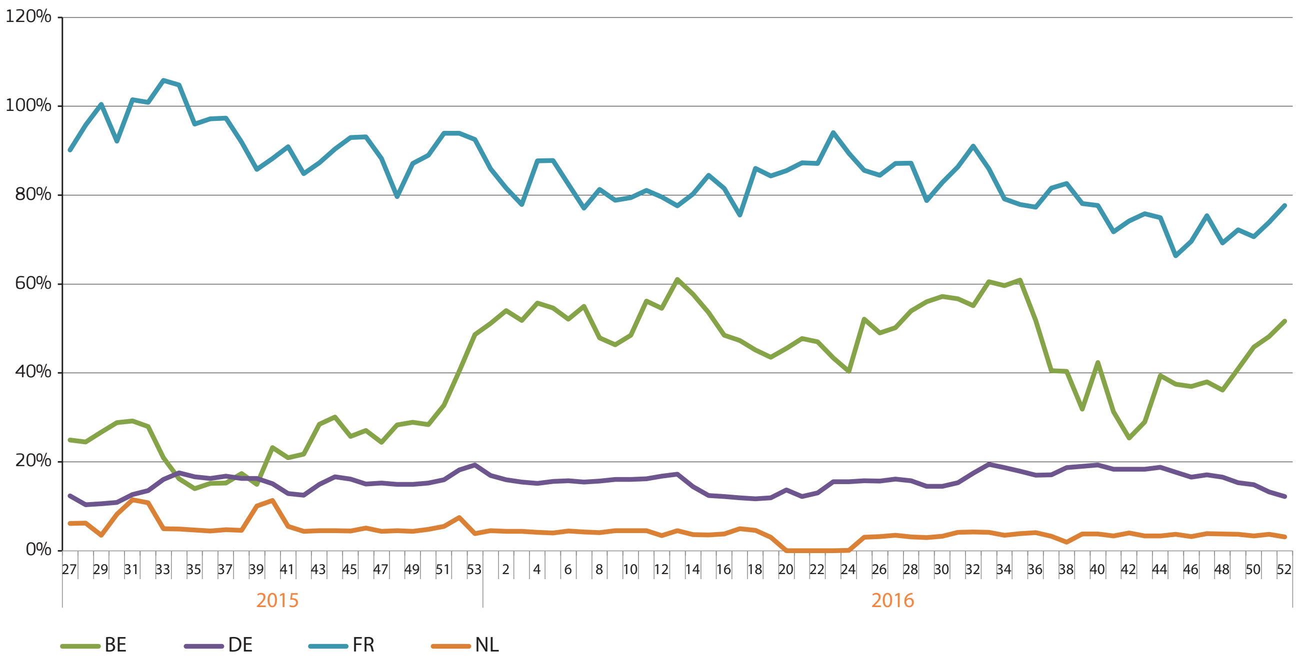
Source: Platts, EPEX

FIGURE 17 – WEEKLY AVERAGE WHOLESALE POWER PRICES IN THE CWE REGION



Source: Platts.

FIGURE 18 – THE SHARE OF NUCLEAR POWER GENERATION IN DOMESTIC ELECTRICITY CONSUMPTION IN THE COUNTRIES OF THE CENTRAL WESTERN EUROPE REGION



Source: ENTSO-E

4.2 British Isles (UK, Ireland)

- The UK wholesale day-ahead baseload price rose from 58 €/MWh measured in September 2016 to 76 €/MWh in November, but in December 2016 it fell back to the level measured in September. Meanwhile, the monthly average baseload price in Ireland followed a similar pattern, rising from 38 €/MWh in September to 55 €/MWh in November 2016. In December the Irish price remained close to the average of November 2016.

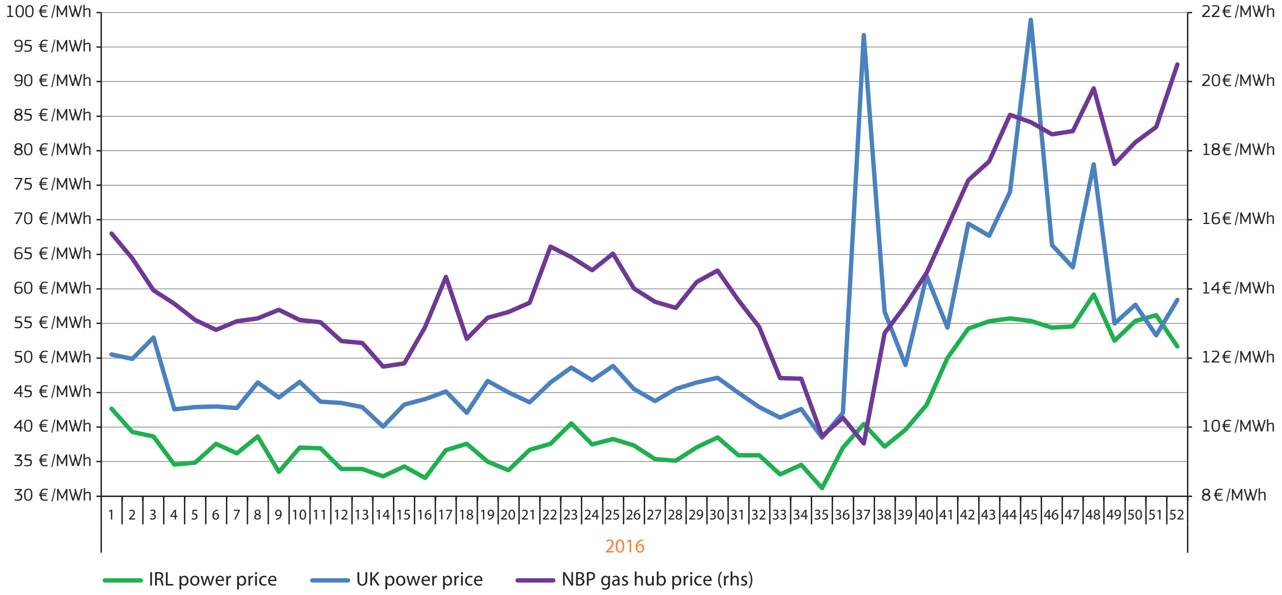
- During Q4 2016 there were several price spikes, primarily owing to lower than usual electricity interconnector availability with France and the Netherlands and occasional cold snaps, especially in November (for example, on 7 November 2016 the daily average price was 168 €/MWh, being the highest in more than a decade - since 17 March 2006).

- Given the issue of the interconnector availability during the whole Q4 2016, natural gas prices on the NBP hub had a lower than usual impact on the wholesale electricity market in the UK, as Figure 19 shows. In December 2016, although gas prices continued to increase, wholesale electricity prices managed to decrease from the extremely high levels of the preceding month. This was mainly due to milder weather conditions and decreasing demand for electricity at the end of the year. As Ireland became self-sufficient in electricity generation over the last few years (or even net exporter to the UK in some periods), the impact of increasing gas prices could be better tracked in the evolution of the Irish wholesale price contracts, in the lack of interconnection availability issues being similar to the UK.

- Figure 20 shows the monthly evolution of the electricity generation mix in the UK in 2015 and 2016. The share of coal-fired generation in the UK electricity mix went down substantially in 2015 and 2016 (while in Q1 2015 coal assured nearly 40% of the generation mix, in Q4 2016 its share was barely 10%). This was mainly due to the increase in the UK carbon tax, which reduced the profitability of coal fired generation (see Figure 7 in Chapter 2.1). Due to higher electricity market prices in Q4 2016 coal-fired generation slightly picked up, however it remained uncompetitive vis-à-vis natural gas. Wind and solar still remained marginal in the UK power mix, in parallel with a stable share of nuclear (around 20% on average).

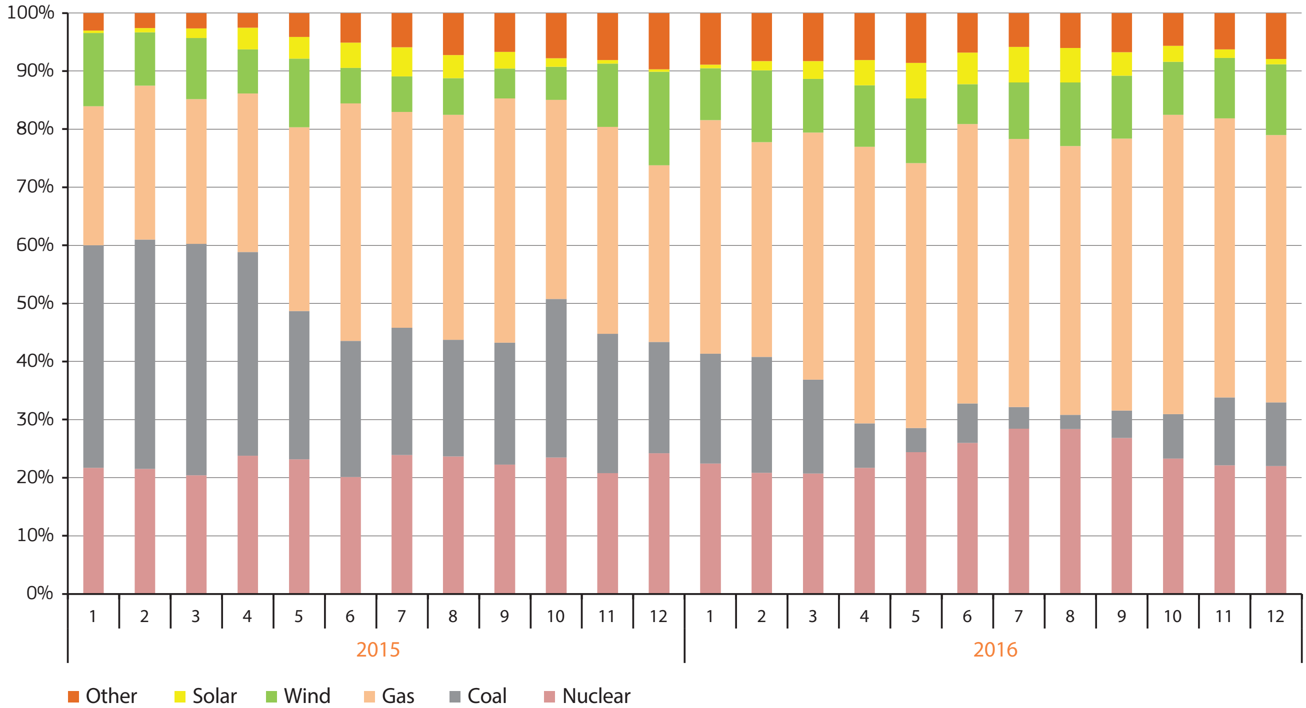
- As Figure 21 shows, in Q4 2016 net electricity imports from France remained at moderate levels, corresponding to the inter-connection limitations between the UK and France. However, in spite of limited electricity inflows, price premium to France shrank considerably compared to the previous quarter. This was mainly the consequence of high wholesale electricity prices in France. In November-December 2016 the UK even became a net electricity exporter to France, and British prices were often lower than the French peers, which is a quite rare event.

FIGURE 19 – WEEKLY AVERAGE POWER PRICES IN THE UK AND IRELAND, IMPACTED BY GAS PRICES



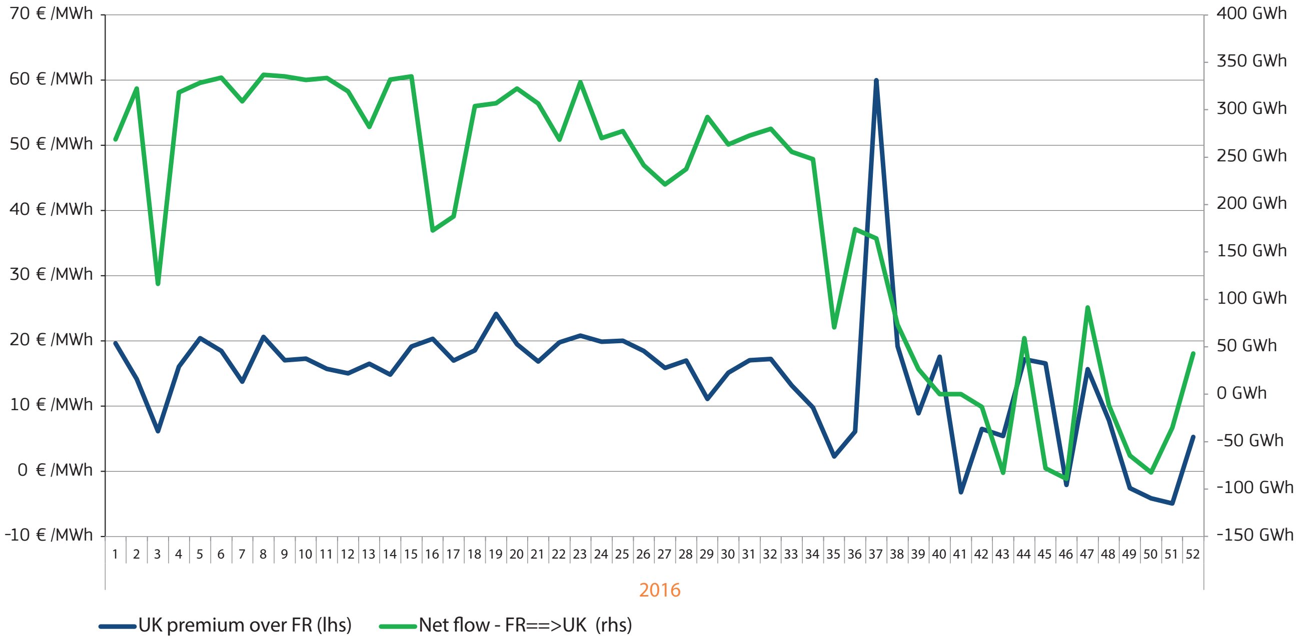
Source: Platts, SEMO

FIGURE 20 – MONTHLY EVOLUTION OF THE ELECTRICITY GENERATION MIX IN THE UK



Source: ENTSO-E

FIGURE 21 – WEEKLY UK PRICE PREMIUM OVER THE FRENCH MARKET AND NET ELECTRICITY INFLOW FROM FRANCE



Source: Platts, ENTSO-E

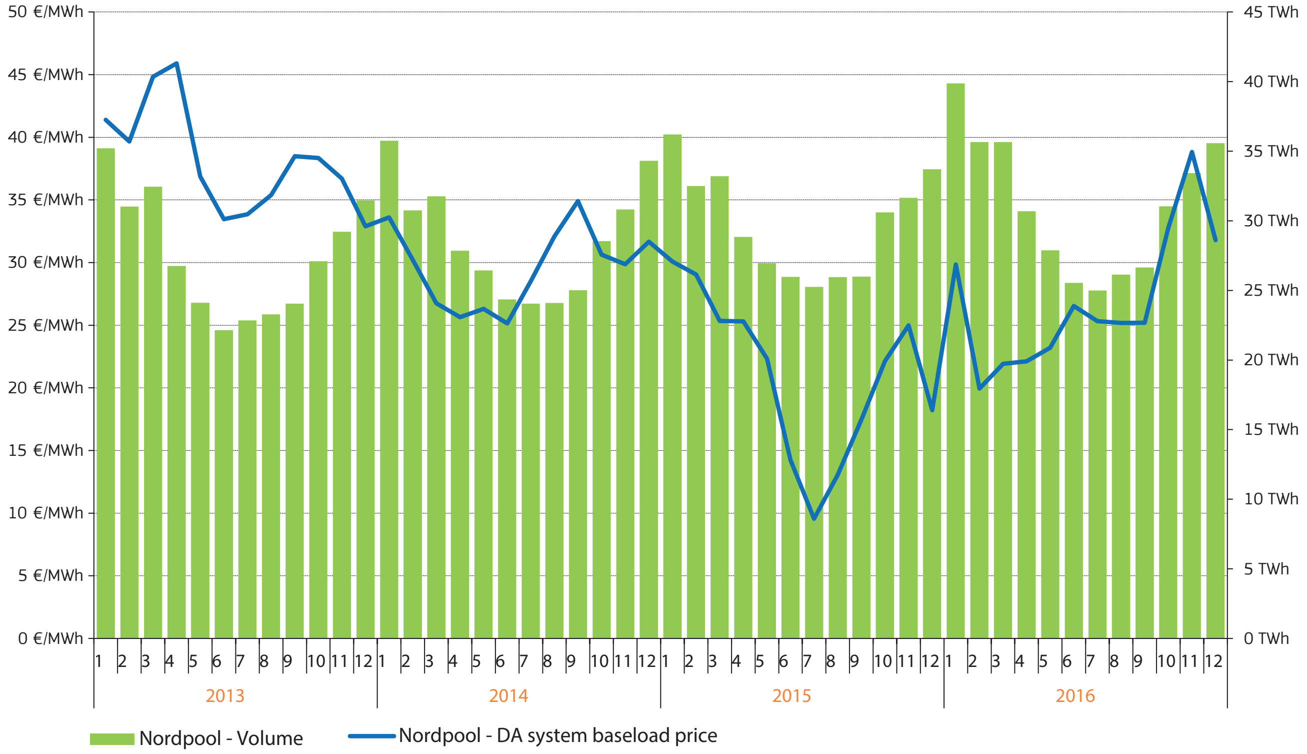
4.3 Northern Europe (Denmark, Estonia, Finland, Latvia, Lithuania, Norway, Sweden)

- Similarly to many other European countries, the monthly average wholesale system electricity price in the Nordpoolspot market peaked in November 2016 and reached 40 €/MWh on average, being the highest since April 2013, as Figure 22 shows.

- This was mainly due to the lowest hydro availability in the Nordic region in the last four years in November-December 2016, as Figure 23 shows. Given the lower than usual precipitation across the region, this cheap resource of electricity generation had to be substituted with other electricity sources and power imports. In mid-November 2016 (week 46) hydro levels were lower by 20% compared to the same week of 2015 (and they were down by 5-10%, if we compare to 2013 or 2014). In November temperatures were slightly lower than usual, also adding to the pressure on demand for electricity in a region where electric energy has an important role in residential heating.

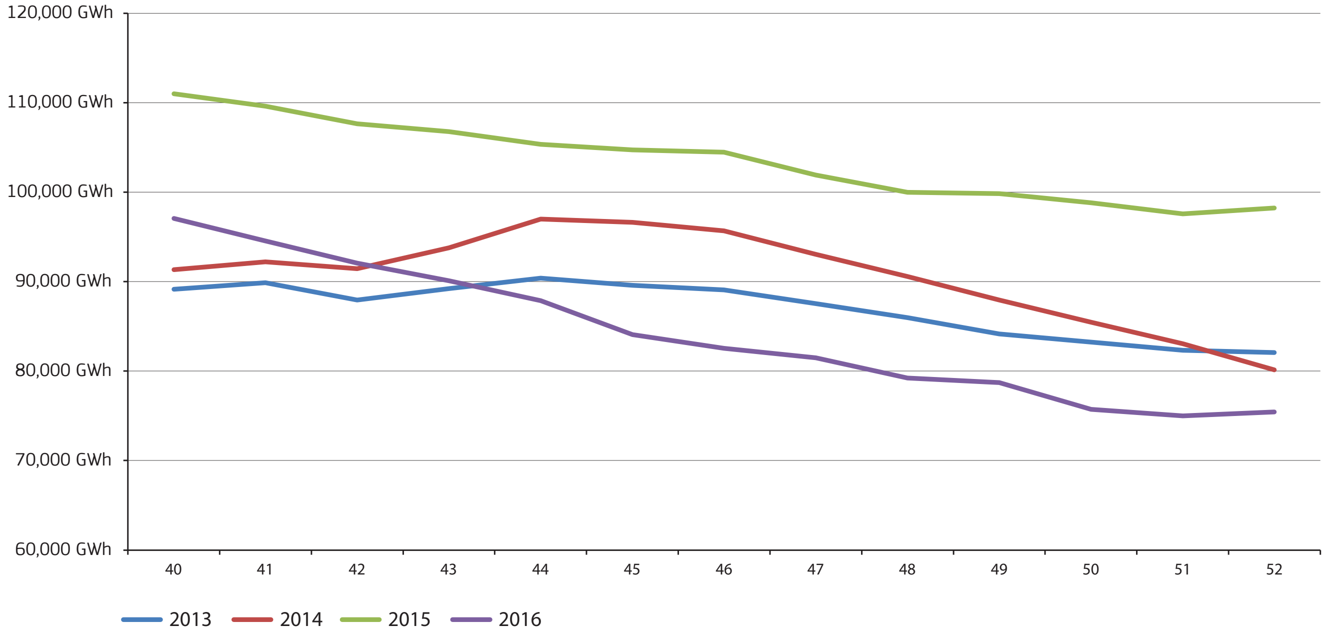
- In the consequence of dwindling domestic electricity generation, the net exporter position of Norway in November 2016 (400 GWh) reached the lowest in three years. In parallel, the Nordic region's electricity flow position turned to net importer, which was not seen since the end of 2013. In spite of having favourable price differentials with Central and Western Europe, the region could not export more electricity due to domestic generation constraints.

FIGURE 22 – MONTHLY TRADED DAY-AHEAD VOLUMES AND PRICES IN NORTHERN EUROPE



Source: Nordpool spot market

FIGURE 23 – WEEKLY COMBINED HYDRO RESERVOIR LEVELS (NORWAY, SWEDEN AND FINLAND) IN THE FOURTH QUARTER OF DIFFERENT YEARS



Source: Nordpool spot market

4.4 Apennine Peninsula (Italy)

- In the fourth quarter of 2016 the Italian monthly average wholesale baseload price underwent a significant increase: while in September 2016 it stood at 43 €/MWh, in November it reached 58 €/MWh, and receded only slightly in December (56 €/MWh). The daily average price contract reached its peak on 15 November 2016 (80 €/MWh), being the highest since July 2015).

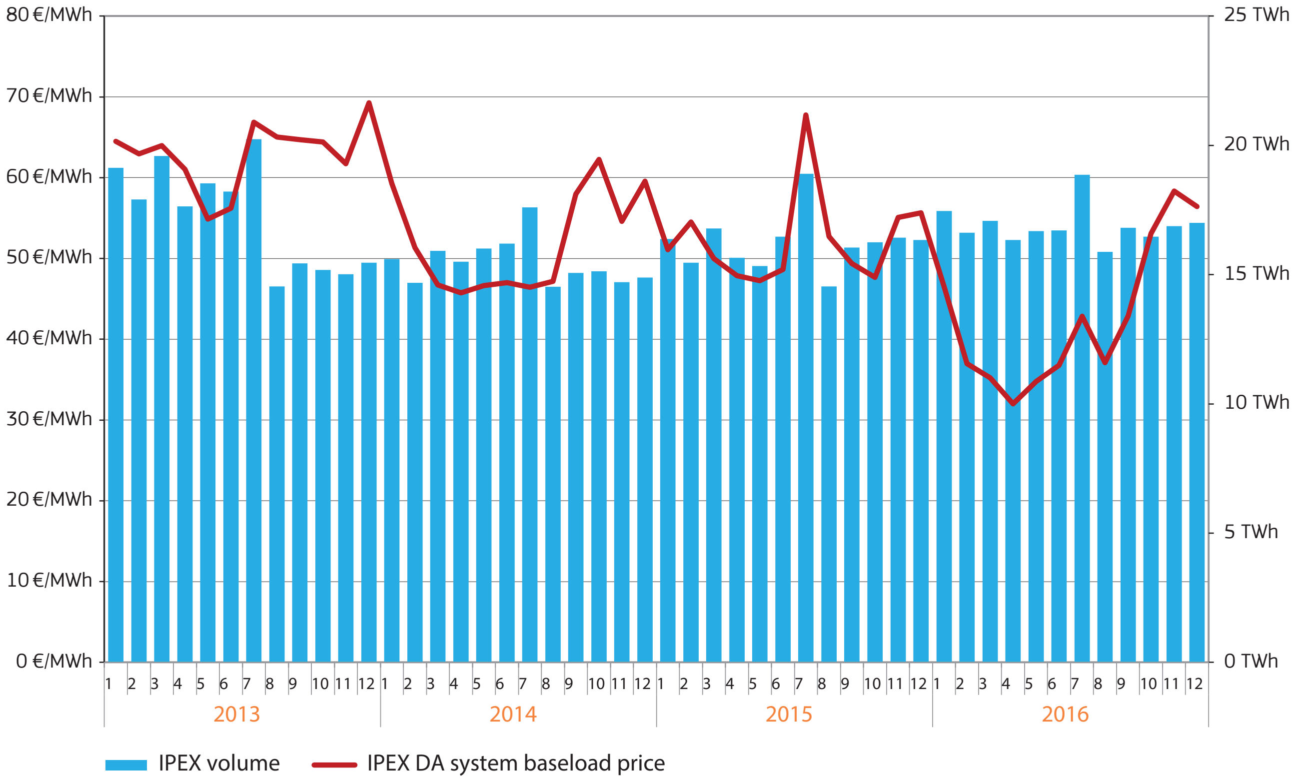
- The principal driver behind this significant price increase in Italy was the lower generation capacity availability in the CWE region, especially in France, which is traditionally a key import source of electricity for Italy. In parallel with increasing wholesale electricity prices on the French market and structurally increasing import needs in the winter season in Italy, Italian wholesale market prices also went up. Imports from France fell to several year lows in December 2016.

- Between October and December 2016 the Italian market had an average of 4 €/MWh price discount to France. At monthly level price discounts to France could be observed for the last time.in October 2009.

- As Figure 25 shows, there was a high seasonality in hydro generation in Italy, and in Q4 2016 the share of hydro dropped significantly (and accounted for around one eighth of the generation mix) compared to the spring-summer months of the year. By its nature solar power generation also decreased in the winter period, and wind could only assure about 7% of the total electricity mix in Q4 2016.

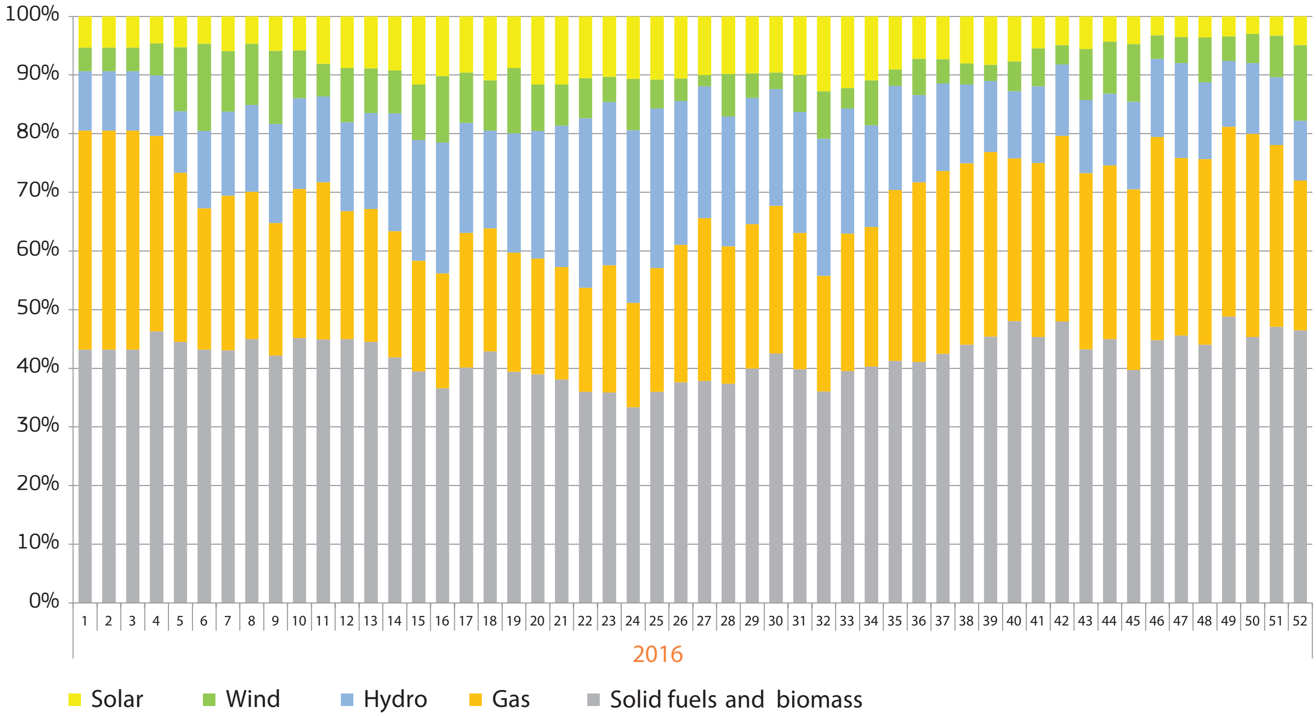
- As hydro and renewable generation sources receded, the share of solid fuels and natural gas gained higher importance in the power mix, (gas accounted for 30% of the generation mix in Q4 2016), and this resulted in increasing electricity generation costs in Italy, being further supported by increasing coal and natural gas prices throughout the quarter.

FIGURE 24 – MONTHLY TRADED DAY-AHEAD VOLUMES AND PRICES IN ITALY



Source: GME (IPEX)

FIGURE 25 – THE EVOLUTION OF THE ELECTRICITY GENERATION MIX IN ITALY IN 2016



Source: ENTSO-E

4.5 Iberian Peninsula (Spain and Portugal)

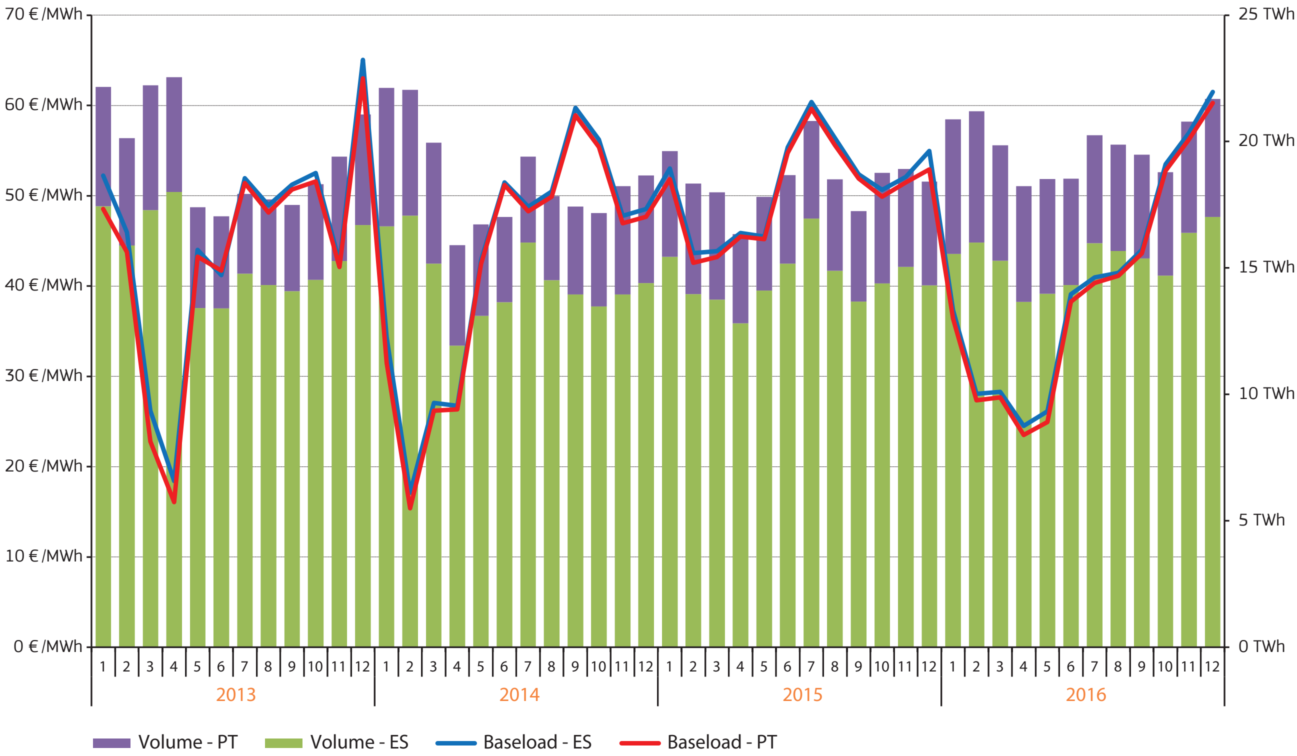
- Contrary to most of the European markets, the monthly average wholesale baseload contracts in Spain and Portugal reached their peak in December 2016 (and not in November). As Figure 26 shows, the monthly average baseload wholesale electricity price in Spain was 62 €/MWh, while in Portugal it reached 60 €/MWh in December 2016, being the highest in both countries since December 2013.

- The share of wind power generation in the Spanish electricity mix fell to 13% in December 2016 and was lower by 4% in Q4 2016 on average if compared to the fourth quarter of 2015, as Figure 27 shows. Dwindling wind power generation was mainly substituted by the increasing share of natural gas within the electricity mix, shifting towards costlier sources of electricity generation that resulted in increasing wholesale electricity prices.

- Although hydro generation assured around a tenth of the electricity mix in Q4 2016, similarly to the share a year before, hydro reservoir levels, being significantly lower than the ten year average at the end of the year, put an upward pressure on the wholesale electricity price curve.

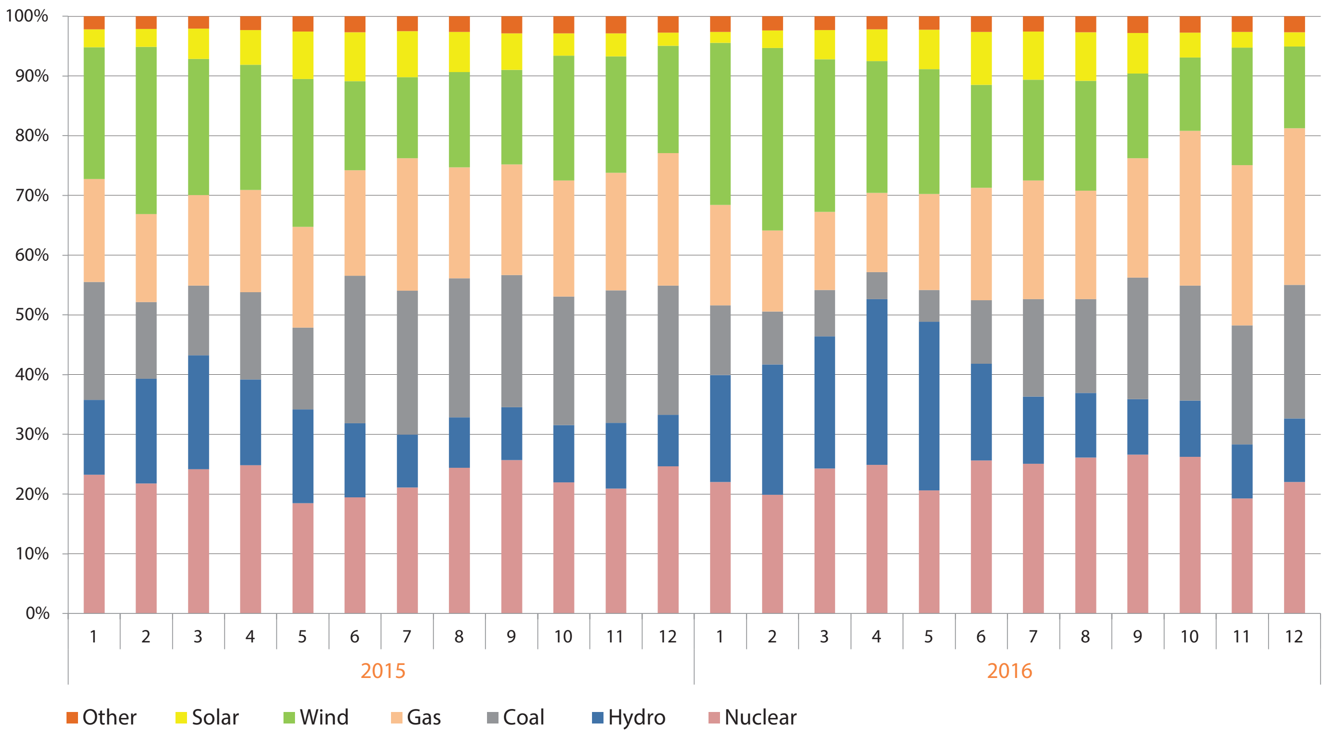
- High wholesale electricity prices in France (see Chapter 4.1), also put a pressure on the Spanish market during Q4 2016, however, as Figure 28 shows, Spain remained net electricity importer from France during most of the time in the quarter, pointing to the lack of sufficient interconnection capacities, that could have enabled the flow of cheaper Spanish electricity to France during the periods of significant French price premiums.

FIGURE 26 – MONTHLY TRADED VOLUMES AND PRICES IN THE IBERIAN PENINSULA



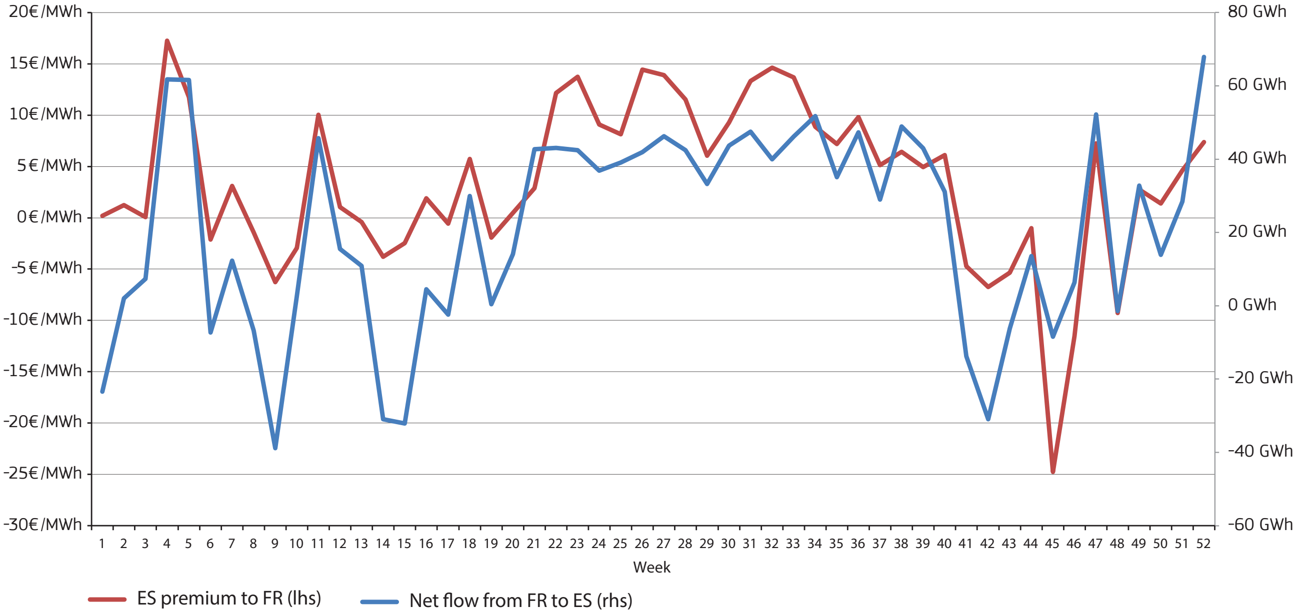
Source: Platts, OMEL

FIGURE 27 – MONTHLY EVOLUTION OF THE ELECTRICITY GENERATION MIX IN SPAIN



Source: ENTSO-E

FIGURE 28 – WEEKLY AVERAGE SPANISH ELECTRICITY PRICE PREMIUM OVER FRANCE AND WEEKLY NET ELECTRICITY FLOWS BETWEEN THE TWO COUNTRIES IN 2016



Source: Platts, OMEL, ENTSO-E

4.6 Central Eastern Europe (Czech Republic, Hungary, Poland, Romania, Slovakia, Slovenia)

- In contrast to Central Western Europe and many other European power regions, the regional monthly average baseload price in Central and Eastern Europe (CEE) showed only a moderate increase between September and December 2016, rising from 35 €/MWh to 41 €/MWh (though in October it reached 43 €/MWh on average). At the same time, the monthly peakload average went up from 42 €/MWh to 51 €/MWh, peaking meantime in October at 53 €/MWh, as Figure 29 shows.

- As wholesale electricity prices increased in Central Western Europe and cheap renewable electricity import sources from Germany were redirected to France and to other markets of that region, Central Eastern Europe had to rely on domestic generation sources, mainly solid fuels and nuclear. On the top of this, cheap hydro generation sources in Romania and the Balkans were abundantly available, providing competitive import opportunities, helping to keep wholesale price increase under control in the whole CEE region.

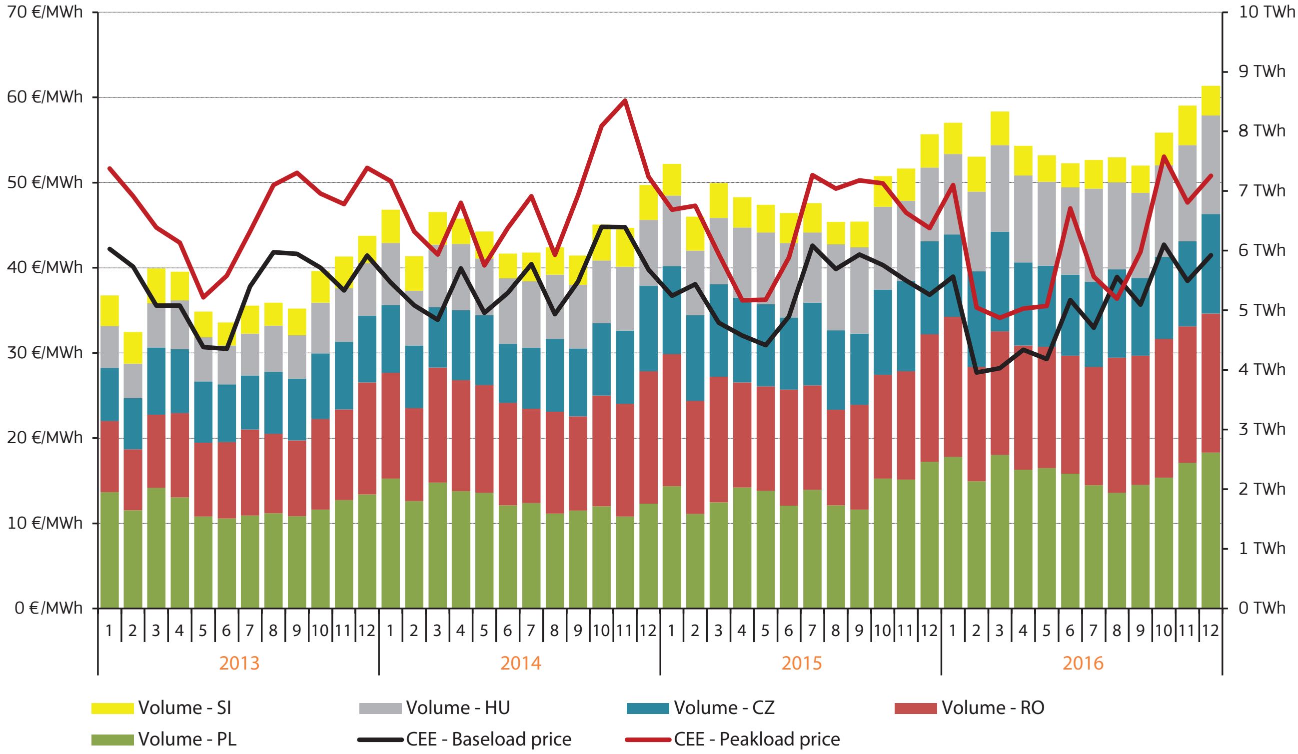
- October 2016 was colder than usual throughout the whole CEE region, which also contributed to increasing demand for electricity and residential heating needs. The remaining part of Q4 2016 temperatures more or less corresponded to the long term averages in most of the countries in the region.

- Figure 30 shows the weekly wholesale electricity price premium of each market in the CEE region to Germany in 2016. In the first half of 2016, and especially during the summer period Poland had a significant wholesale electricity price premium to Germany and to the regional peers, mainly due to ongoing outages in coal and lignite fired generation capacities, in some periods aggravated by interconnection disruptions. However, in Q4 2016 Poland became again the cheapest market in the region, in some periods showing even discounts to the German market, as generation capacities returned and wind power generation ramped up in the country at the end of the year.

- Although in October and December 2016 there were some nuclear generation outages in the Czech Republic, these could only temporarily impact the regional wholesale electricity prices. In Romania wholesale electricity prices were the lower in Q4 2016 than the regional average, due to the abundant hydro and increasing wind power generation. In Hungary, due to significant import needs (around one third of the country's electricity consumption had to be imported in Q4 2016) the local price level was high in regional comparison.

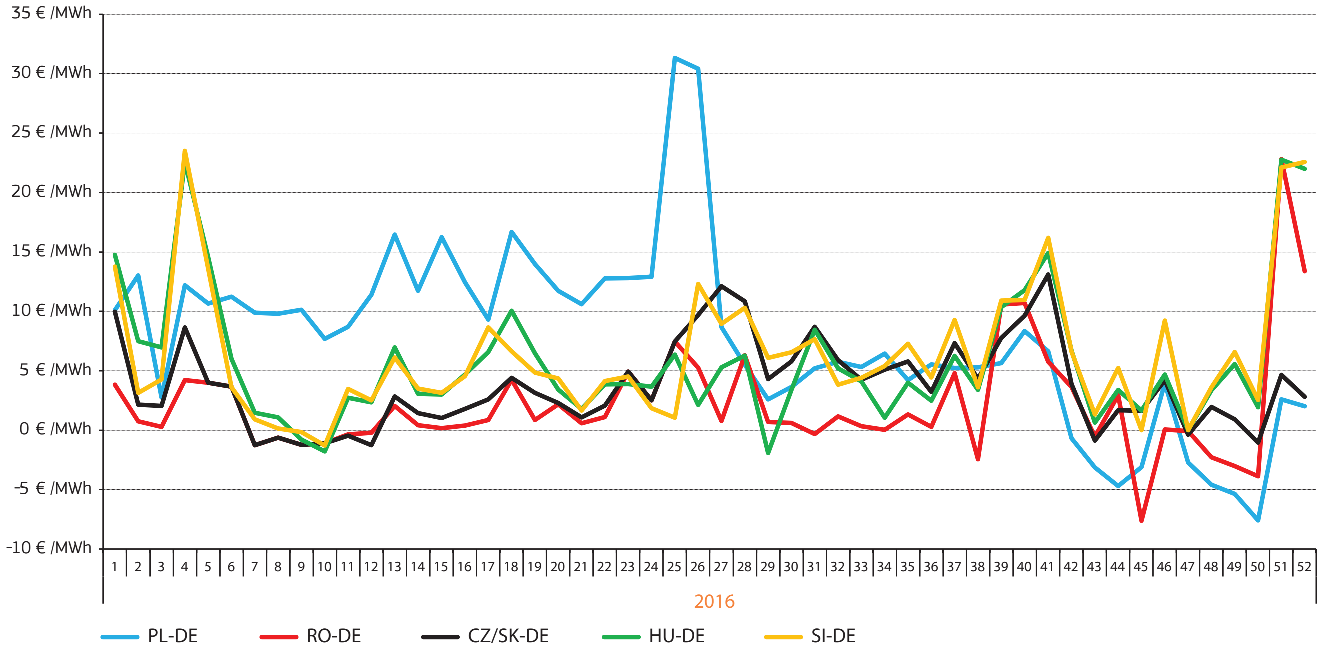
- During the last two weeks of 2016 local wholesale electricity prices in Romania, Hungary and Slovenia decoupled from the Polish and Czech/Slovak prices, as these latter three countries could profit from low prices of, and electricity inflows from the German market, where even negative prices occurred during the Christmas holidays (See Chapter 4.1). The decoupling clearly shows that currently not all CEE countries can profit from eventual cheap flows from Western Europe, pointing to further need of electricity market integration.

FIGURE 29 – MONTHLY TRADED VOLUMES AND PRICES IN CENTRAL EASTERN EUROPE



Source: Regional power exchanges, Central and Eastern Europe (CEE)

FIGURE 30 – REGIONAL WEEKLY BASELOAD PRICE PREMIUMS OR DISCOUNTS TO THE GERMAN MARKET



Source: Platts (EPEX), CEE Regional power exchanges

4.7 South Eastern Europe (Greece and Bulgaria)

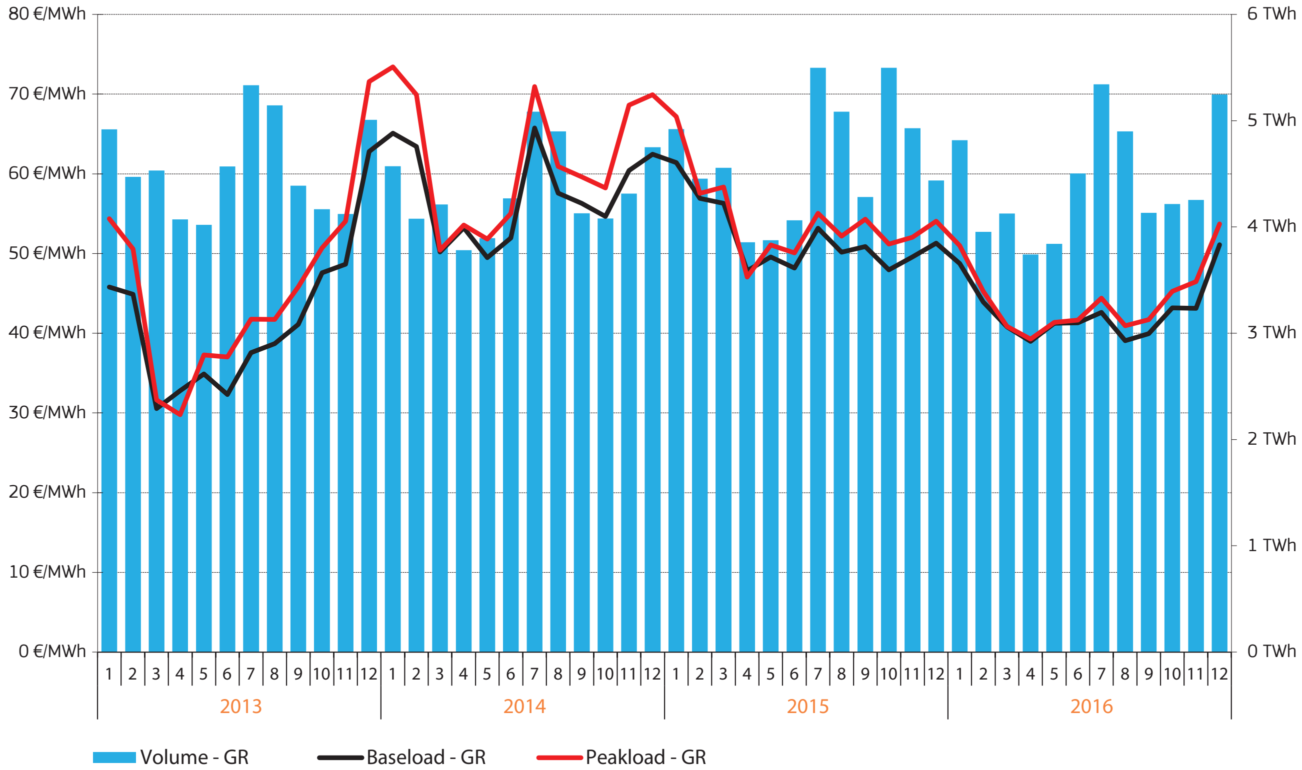
- In the fourth quarter of 2016 the Greek monthly average baseload electricity price, as Figure 31, shows, rose from 40 €/MWh to 52 €/MWh, while at the same time the monthly average peakload contract went up from 42 €/MWh to 54 €/MWh, reaching both baseload and peakload in December 2016 almost identical values to the prices measured in December 2015. However, on 12 December 2016 the daily average wholesale price reached 82 €/MWh, which was the highest since July 2014.

- These price peaks in December 2016 must have been strongly related to the lower than normal temperatures in Greece (see Figure 2), resulting in increasing heating and electricity needs in the residential sector. Furthermore, in parallel with the economic recovery in Greece, demand for electricity in the business sector might have also increased in Q4 2016.

- Over the last two years natural gas has increased its share in the Greek power generation mix, gradually taking over domestically produced lignite. In December 2016 gas-fired generation in Greece reached the highest since July 2011, primarily owing to competitive gas import opportunities and environmental regulation (e.g.: Industrial Emissions Directive – 2010/75/EU), aiming at limiting, amongst others, the operation time of old lignite-fired generation capacities, having significant emissions. During the summer of 2016 the combined share of wind and solar power generation amounted to 20%, however, in Q4 2016 the share of variable renewables receded, as Figure 32 shows. Increasing penetration of variable renewables also give support to gas fired generation, as these renewables assume sufficient amount of flexible back-up capacities which lignite-fired generation cannot really satisfy. Similarly to many other parts of Europe, the weather in Greece was relatively dry, not being favourable for hydro power generation in Q4 2016.

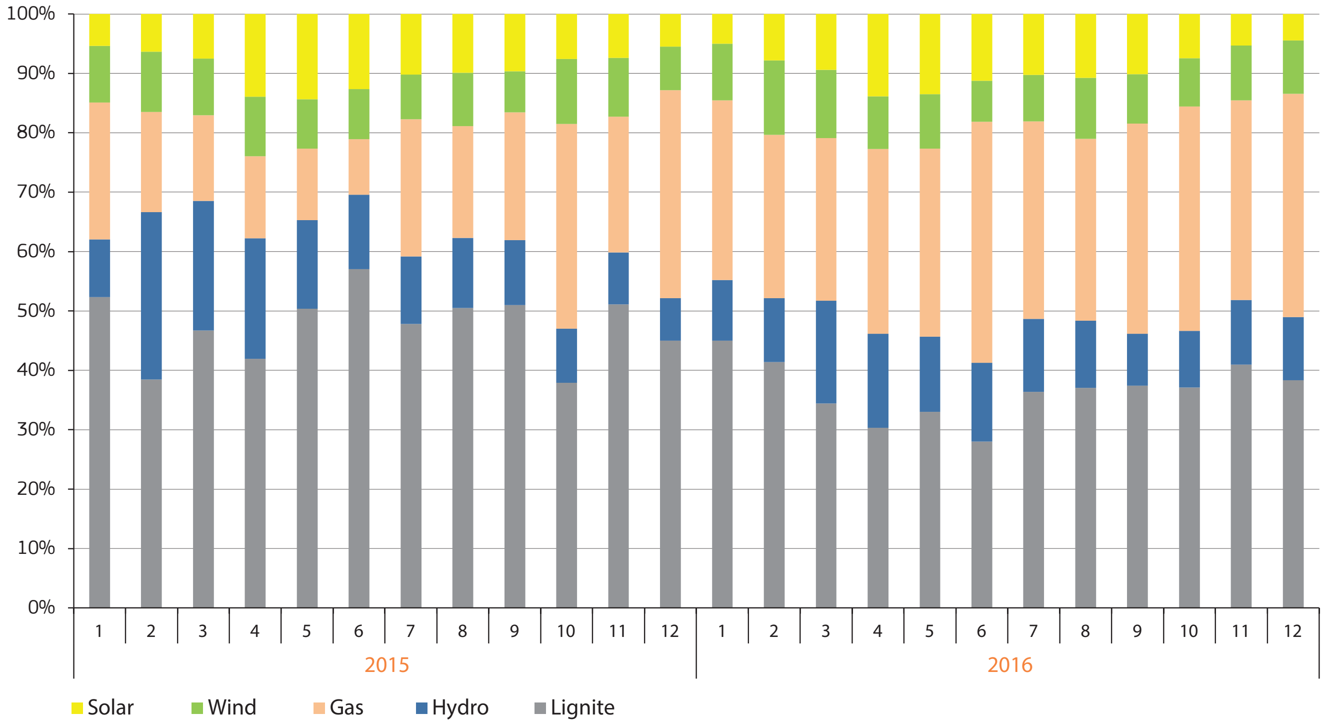
- Decreasing electricity imports in Greece also contributed to increasing electricity prices as cheap import sources from the Balkan countries had to be replaced by costlier domestic fossil fuel electricity generation, resulting in higher wholesale market prices. In December 2016 the net importer position of Greece (215 GWh) was the lowest since January 2014.

FIGURE 31 – MONTHLY TRADED VOLUMES AND PRICES IN GREECE



Source: DESMIE

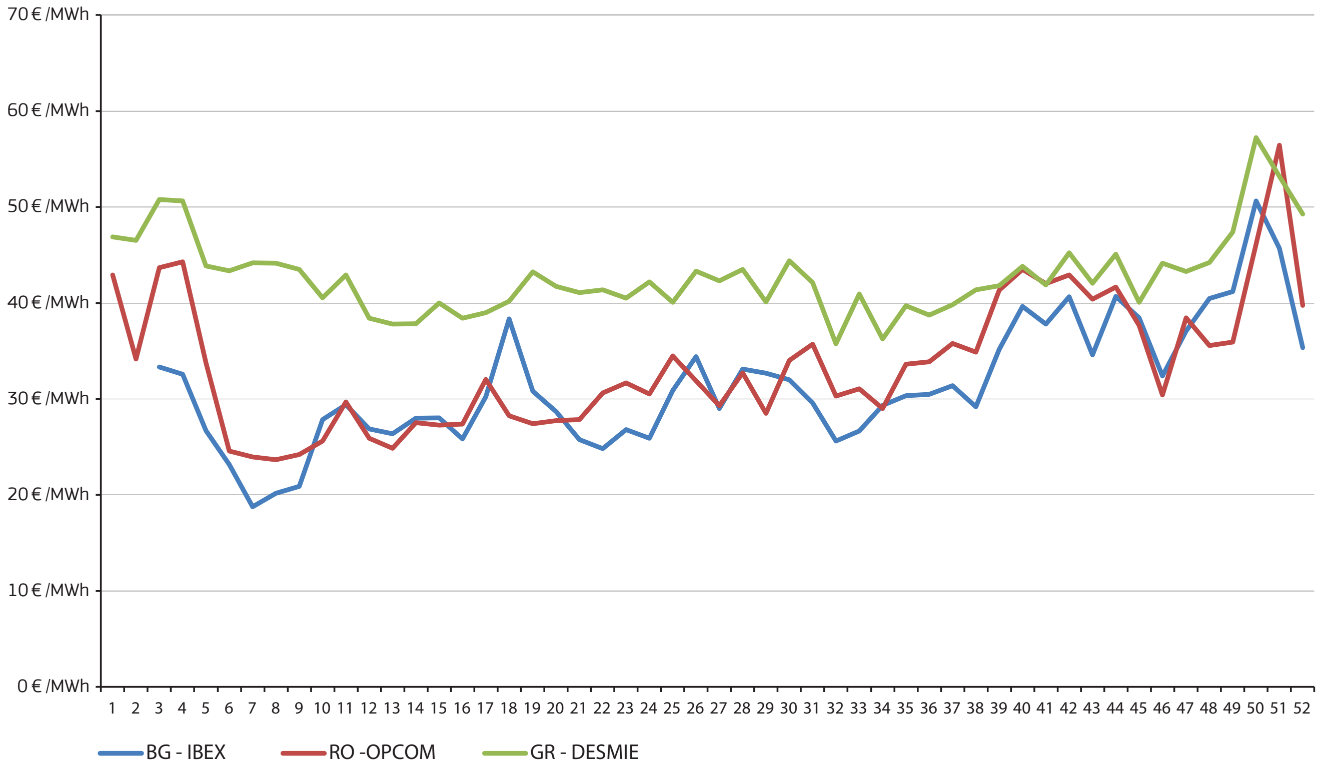
FIGURE 32 – MONTHLY EVOLUTION OF THE ELECTRICITY GENERATION MIX IN GREECE



Source: ENTSO-E

- In the fourth quarter of 2016 the day-ahead prices in Bulgaria remained well aligned with the Romanian and Greek peers, as Figure 33 shows. Although power generation was abundant in Bulgaria during Q4 2016, the country's net electricity exporter position decreased (reaching only 368 GWh in November 2016, being the lowest since June 2013). Colder than normal weather in December 2016 resulted in an extra demand for electricity, which lifted the wholesale prices at the end of the year.

FIGURE 33 – COMPARISON OF WEEKLY AVERAGE DAY-AHEAD PRICES IN BULGARIA, GREECE AND ROMANIA IN 2016

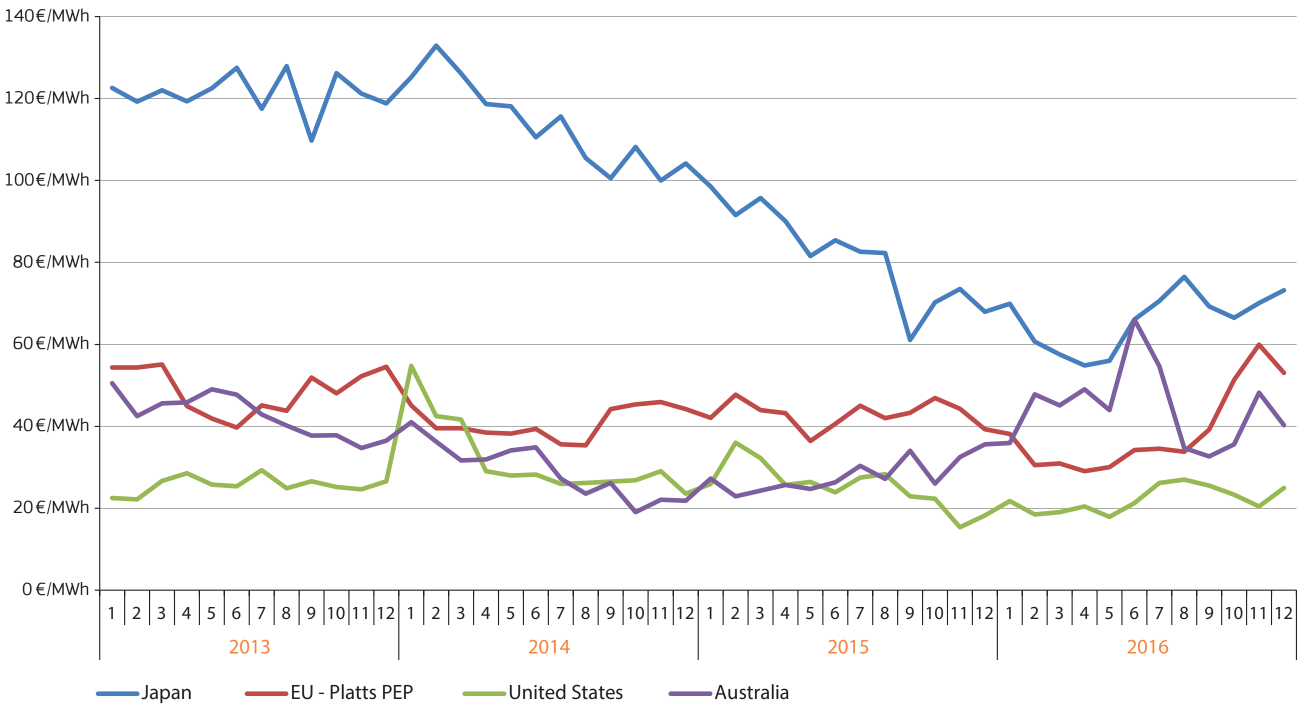


Source: IBEX, DESMIE, OPCOM

5. International outlook
comparing EU power prices with international peers

- As Figure 34 shows, in the fourth quarter of 2016 the gap between wholesale electricity prices in Europe and the US widened again, as prices in Europe increased. In Australia wholesale prices also went up, relating to increasing international coal prices in the fourth quarter of 2016. In Japan the wholesale electricity prices also increased, in the consequence of increasing LNG prices in the Asian markets.

FIGURE 34 – COMPARISON OF THE MONTHLY AVERAGE WHOLESALE ELECTRICITY PRICES IN EUROPE, US, JAPAN AND AUSTRALIA



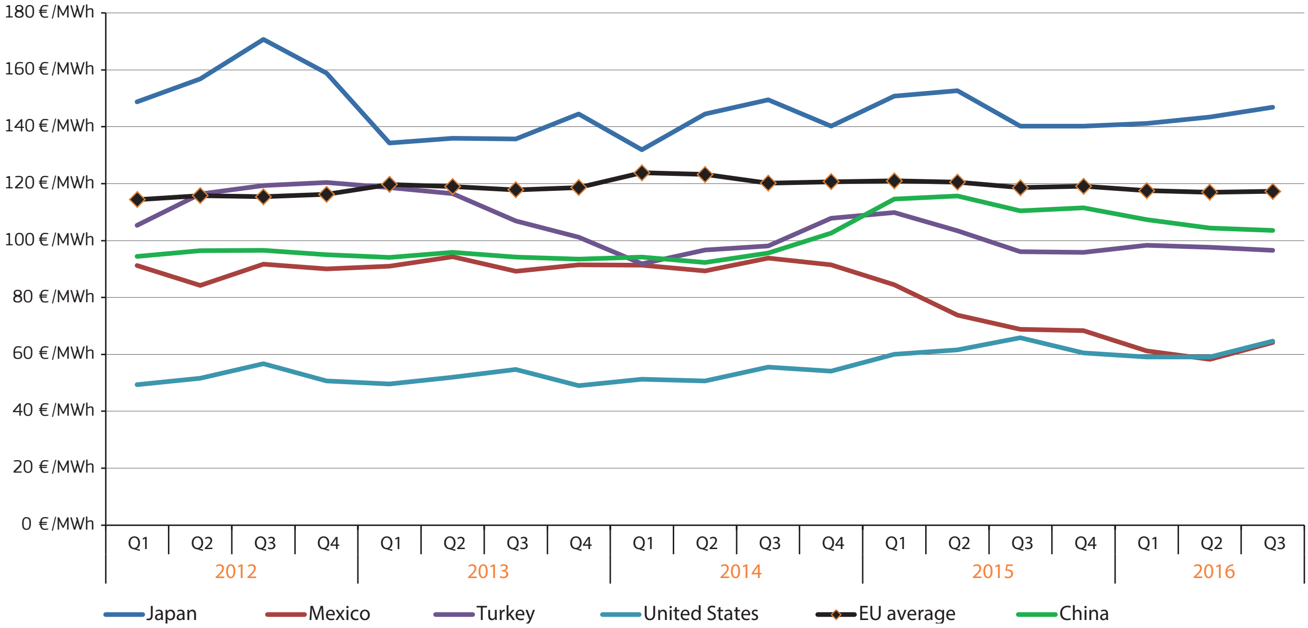
Source: Platts PEP, JPEX (Japan), AEMO (Australia) and the average of PJM West and ERCOT regional wholesale markets in the United States

- In this report retail electricity prices paid by European industrial customers are compared with industrial electricity prices in the United States, Japan, China, Mexico and Turkey, as Figure 35 shows.

- Similarly to the differences in wholesale prices, in Q3 2016 industrial customers in the United States had to pay about half as much for electricity than in the EU on average. In Mexico prices were similar to the US, contrarily to situation a few years ago, when they had a significant premium to the US peers. In contrast, customers in Japan had to pay 20% more than their European counterparts.

- In Turkey the industrial electricity price has been lower than the EU average by 10-20% over the last few quarters, and in China, even though prices were close to the European peers, in 2015, in Q3 2016 a 15% price discount to the EU average could be observed, likely related to the depreciation of the Chinese national currency to the euro.

FIGURE 35 – COMPARISON OF THE AVERAGE EU RETAIL ELECTRICITY PRICE PAID BY INDUSTRIAL USERS WITH THE PRICES OF SOME INTERNATIONAL COMPETITORS



Source: IEA, CEIC, Eurostat and own computations

6. Retail electricity prices in the EU

- Figure 36 and Figure 37 show the evolution of the monthly estimated retail electricity prices in the 28 EU Member States for industrial customers and households with less than medium level annual electricity consumption (Eurostat bands IB and DB) Normally the lower is the annual electricity consumption of a given customer, the higher price this customer needs to pay per kWh.

- Retail prices paid by households include all taxes, while retail prices paid by industrial customers are prices without VAT and recoverable taxes and levies. Monthly retail electricity prices are estimated by using the Harmonised Consumer Price Indices (HICP) for the household prices and the Producer Price Indices (PPI) for the industrial customers, based on the time series of twice-yearly retail energy price data from Eurostat.

- In the case of industrial customers with low annual consumption Spain was the most expensive country at the beginning of 2017, while Sweden was the cheapest. At the same time in the case of household retail electricity prices retail electricity prices for households were the lowest in Bulgaria, while households with low annual consumption had to pay the most in Spain.

- Figure 38 and Figure 39 show the different behaviour of industrial and household retail price convergence across the EU, using relative standard deviation of the retail electricity prices as metric. Relative standard deviation enables to compare the dispersion of values of different magnitudes, as by dividing the standard deviation by the average the impact of absolute values is eliminated, making possible the comparison of different time series on a single chart. In the case of industrial customers there is a convergence in retail electricity prices, as the relative standard deviation mostly decreases over time, even though there are some temporary deviations from this trend. However, in the case of households the relative standard deviation even increased in the last two years, implying divergence of household retail prices across the EU.

- The convergence of wholesale electricity prices across Europe can be better tracked in the convergence of retail industrial prices, as industrial customers are normally not subject to regulated end-user prices, have better bargaining power at concluding electricity purchase contracts, and the share of the so-called energy supply component (showing strong correlation with wholesale electricity prices) is higher in their final retail price, whereas the share of non-market elements, such as network costs, taxes and levies are lower than in the case of households. As retail household prices contain VAT and other non-recoverable taxes and levies, the increasing importance of the tax in the final household retail prices item is an important factor behind the non-convergence of household retail prices across the EU.

- In the case of industrial customers, having medium level annual electricity consumption (Band IC), the monthly ratio of the highest and the lowest price in the EU was 2.3 (Sweden: 6.5 Eurocent/kWh, Germany: 15.3 Eurocent/kWh), while in the case of large industrial customers it was 3.0 (Sweden: 4.1 Eurocent/kWh, UK: 12.2 Eurocent/kWh). In the case of households with medium level annual consumption (Band DC) the highest-lowest price ratio was 3.2 (Bulgaria: 9.6 Eurocent/kWh, Denmark: 30.8 Eurocent/kWh) in January 2017.

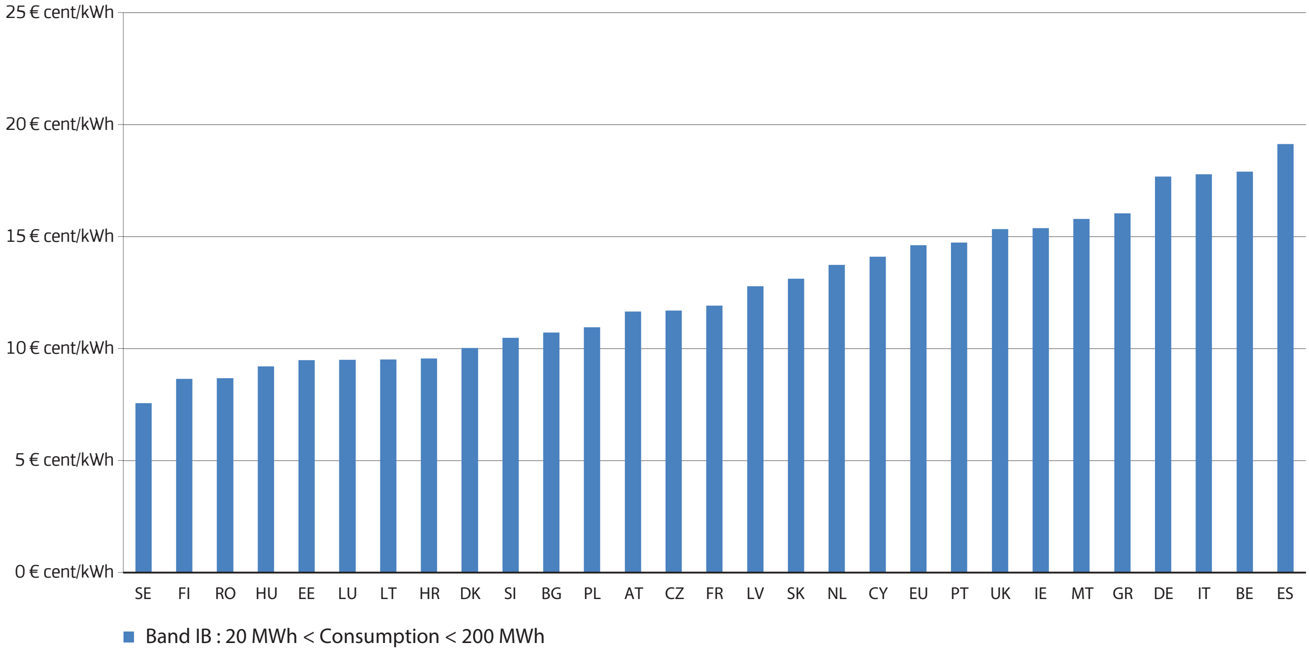
- Figure 40 shows the retail electricity price element of the so-called Household Energy Price Index (HEPI), calculated with a methodology developed by Vaasaett on the basis of monthly collection of electricity invoices in the capital cities of the EU. In January 2017 the highest retail electricity prices paid by households could be observed in Copenhagen (32.4 Eurocent/kWh) and Berlin (30.4 Eurocent/kWh), while the cheapest capitals in the EU were Sofia (10.6 Eurocent/kWh) and Bucharest (11.1 Eurocent/kWh). Compared with January 2016, the biggest price increase could be observed in Tallinn (11.4%) and Madrid (11.3%), while retail electricity prices decreased the most in Brussels (16%), Riga (11%) and Bucharest (10%).

- Figure 41 shows the change in household retail electricity prices between January 2016 and January 2017, expressed in Eurocent/kWh, and the contribution of cost components (energy costs, transmission and distribution costs, energy taxes and VAT) to the price change in the European capital cities. Energy costs decreased by the most in London, Bratislava and Warsaw, while they went up in Copenhagen and Tallinn. Energy taxes decreased measurably in Copenhagen and Rome, while they went up in Luxembourg and Amsterdam. Transmission and distribution costs had the biggest downward impact on the final retail prices in Brussels and Luxembourg (the distribution component decreased), while they increased the final price in Lisbon and Rome between January 2016 and January 2017.

- In Madrid there were significant changes in the reporting practice of different price components, resulting in re-classification of cost elements from the group of network costs to taxes and levies, better showing the impact of different policy measures (e.g.: capacity payment, renewable generation incentives, annuities of the tariff deficit, etc.). In consequence network costs became lower and the tax component higher compared to the last observation period.

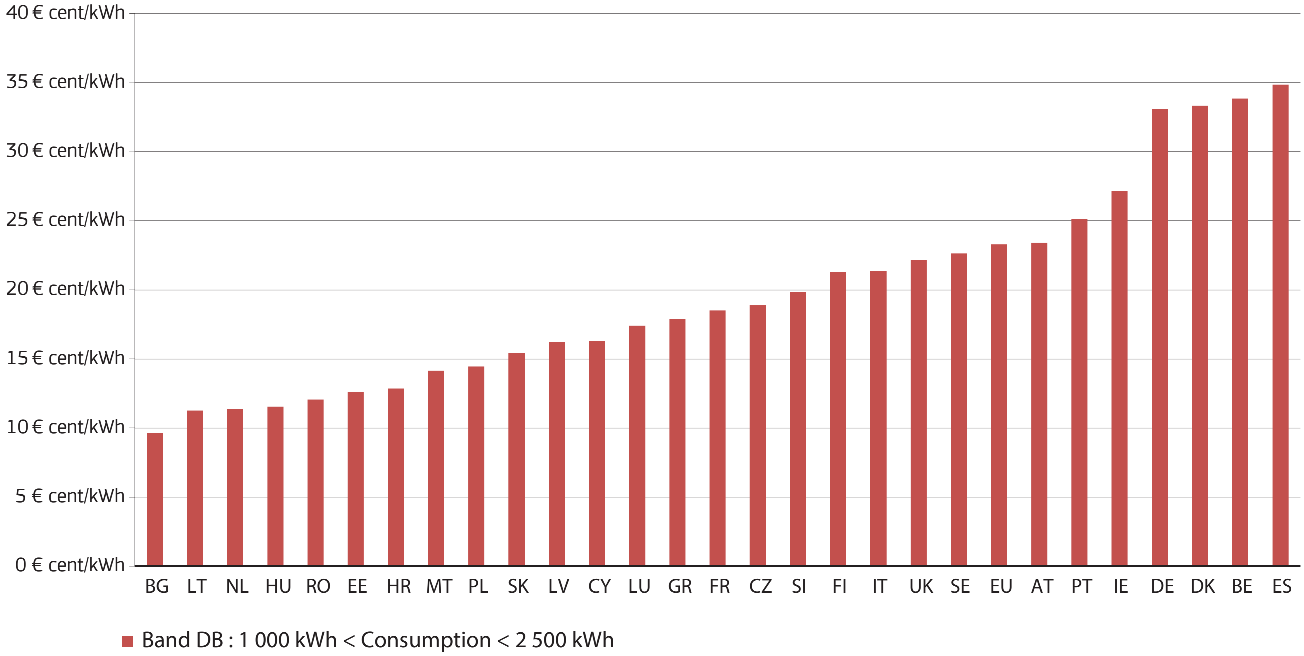
- The two maps (Figure 42 and Figure 43) show the estimated quarterly average retail electricity prices paid by households and industrial customers, having medium level of annual electricity consumption, in the fourth quarter of 2016.

FIGURE 36 – ESTIMATED INDUSTRIAL RETAIL ELECTRICITY PRICES, JANUARY 2017 – BAND IB (ANNUAL CONSUMPTION BETWEEN 20 MWH AND 200 MWH), WITHOUT VAT AND RECOVERABLE TAXES AND LEVIES



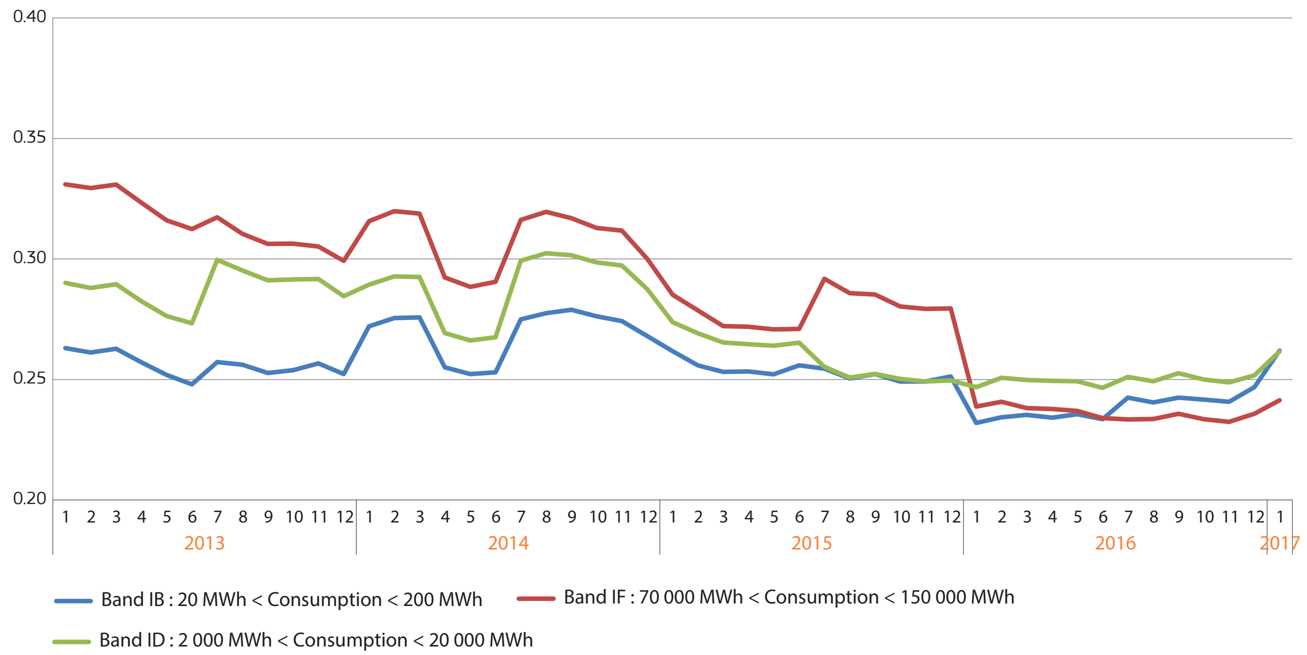
Source: Eurostat, own computations

FIGURE 37 – ESTIMATED HOUSEHOLD RETAIL ELECTRICITY PRICES, JANUARY 2017 – BAND DB (ANNUAL CONSUMPTION BETWEEN 1,000 KWH AND 2,500 KWH), ALL TAXES INCLUDED



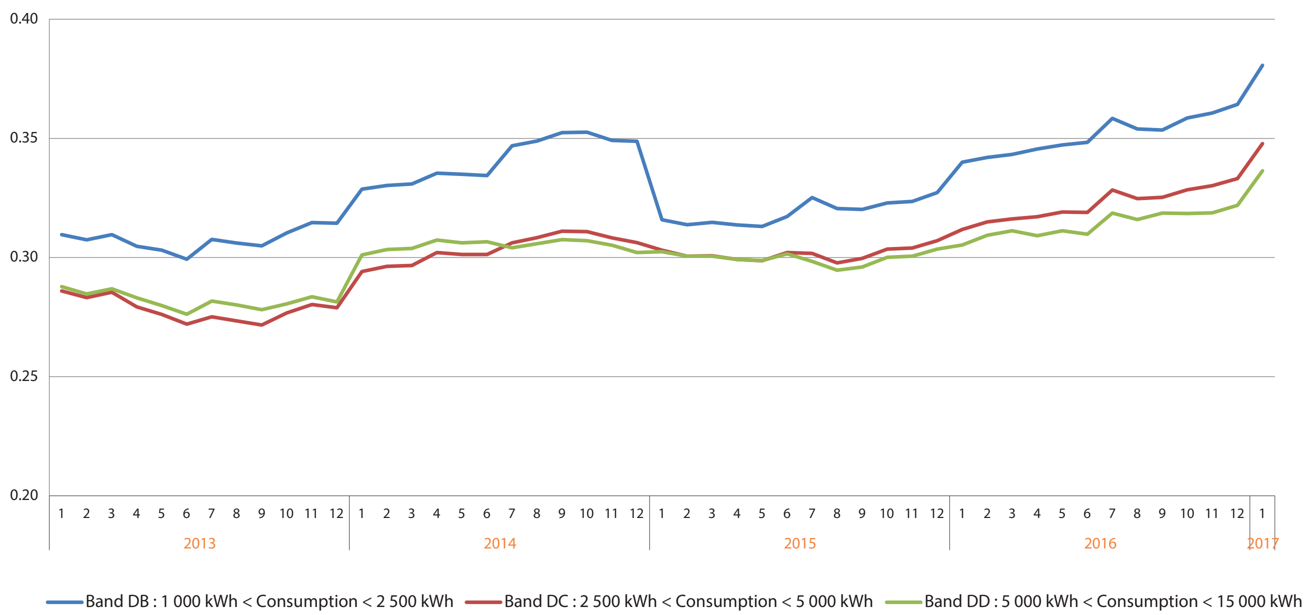
Source: Eurostat, own computations

FIGURE 38 – RELATIVE STANDARD DEVIATION OF RETAIL ELECTRICITY PRICES IN THE EU MEMBER STATES IN THREE INDUSTRIAL CUSTOMER CONSUMPTION GROUPS



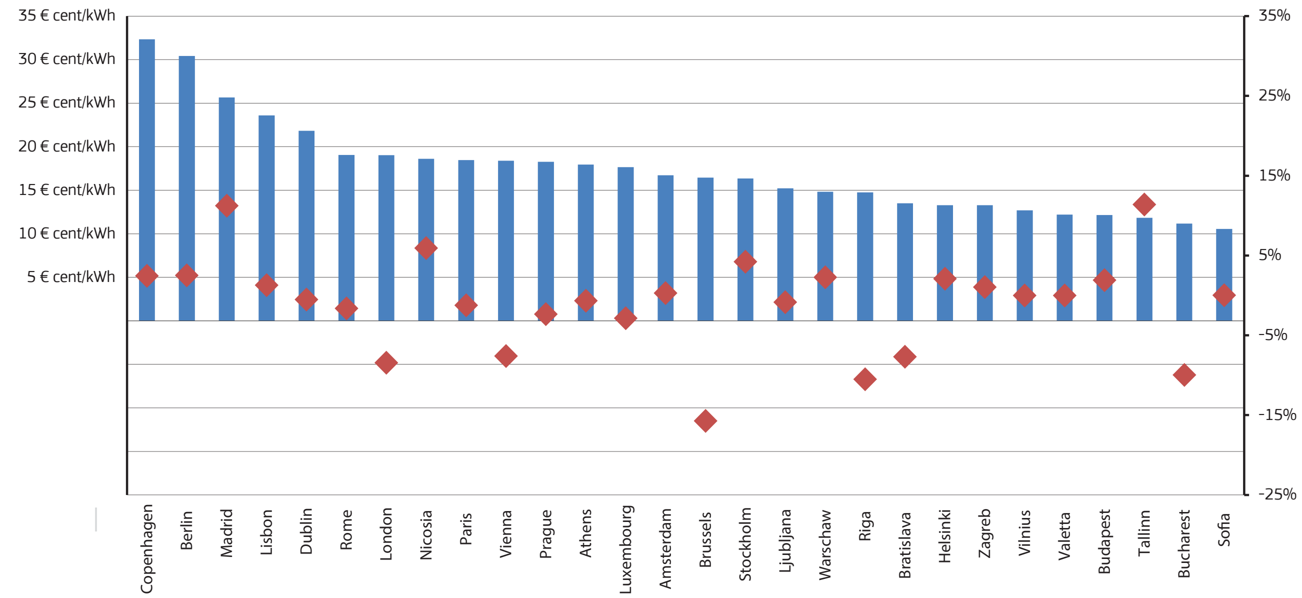
Source: Eurostat, own computations

FIGURE 39 – RELATIVE STANDARD DEVIATION OF RETAIL ELECTRICITY PRICES IN THE EU MEMBER STATES IN THREE HOUSEHOLD CUSTOMER CONSUMPTION GROUPS



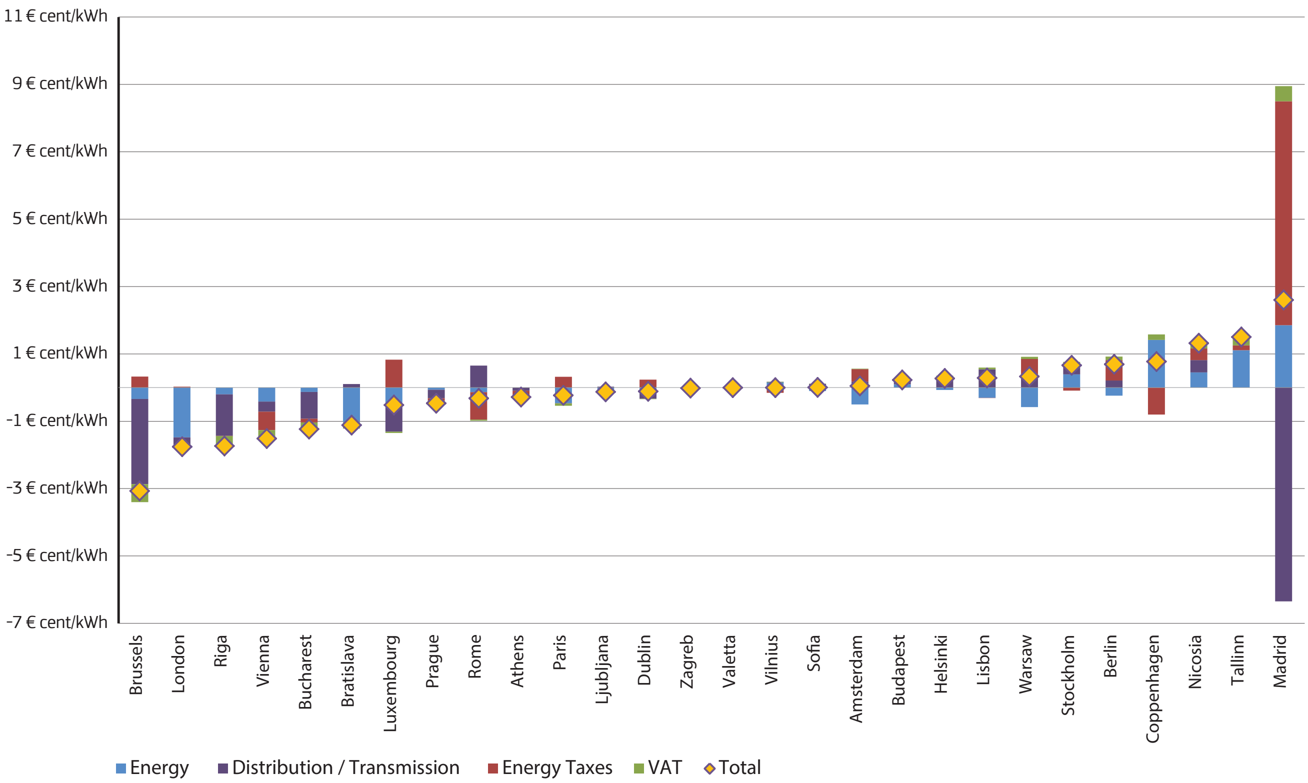
Source: Eurostat, own computations

FIGURE 40 – THE HOUSEHOLD ENERGY PRICE INDEX (HEPI) IN THE EUROPEAN CAPITAL CITIES – ELECTRICITY PRICES IN JANUARY 2017, AND CHANGES IN HOUSEHOLD ELECTRICITY PRICES COMPARED TO JANUARY 2016



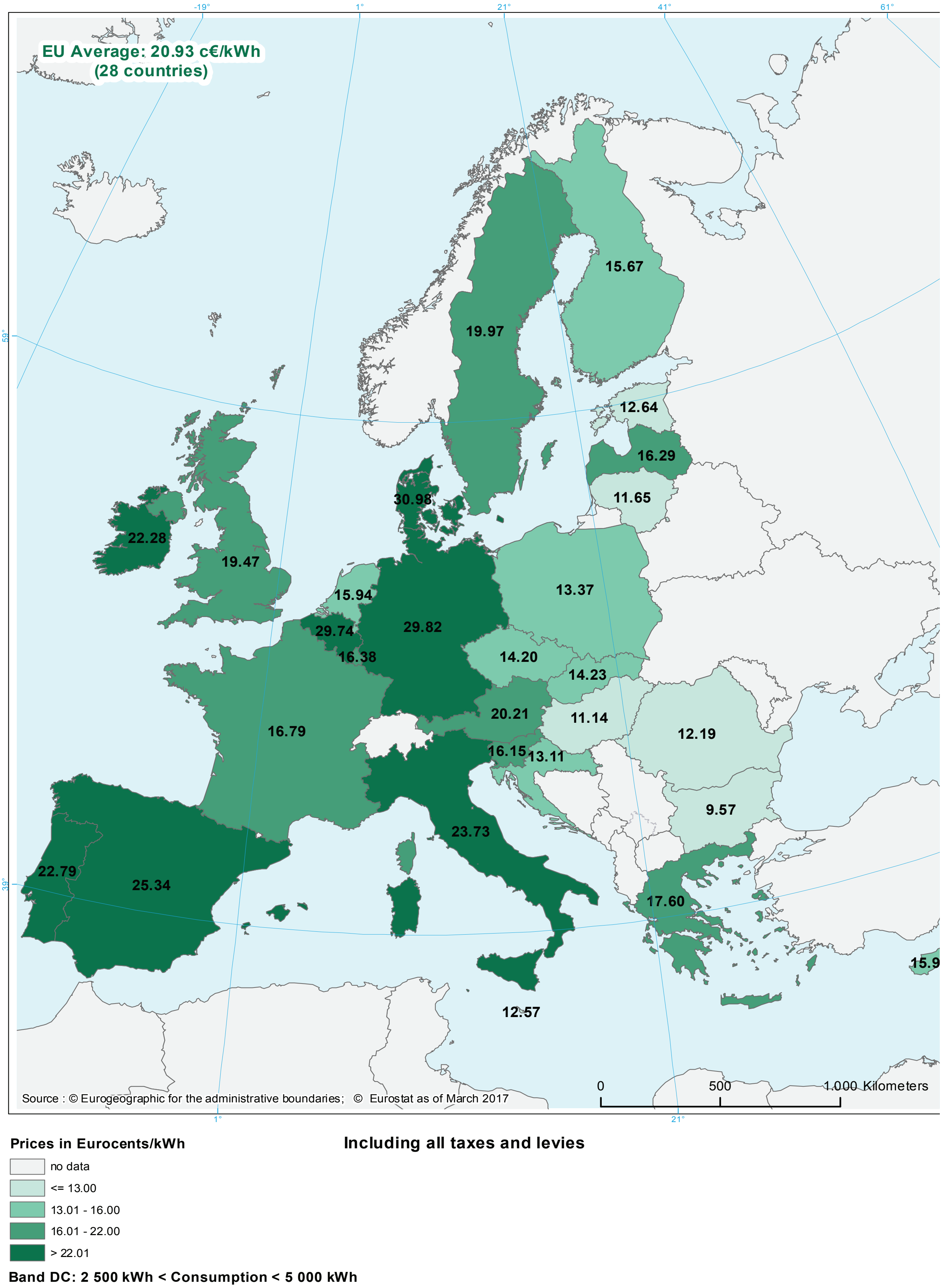
Source: Vaasaett

FIGURE 41 – CHANGE IN ELECTRICITY PRICES AND THEIR COST COMPONENTS IN THE EUROPEAN CAPITAL CITIES, BETWEEN JANUARY 2016 AND JANUARY 2017, IN EUROCENT/KWH



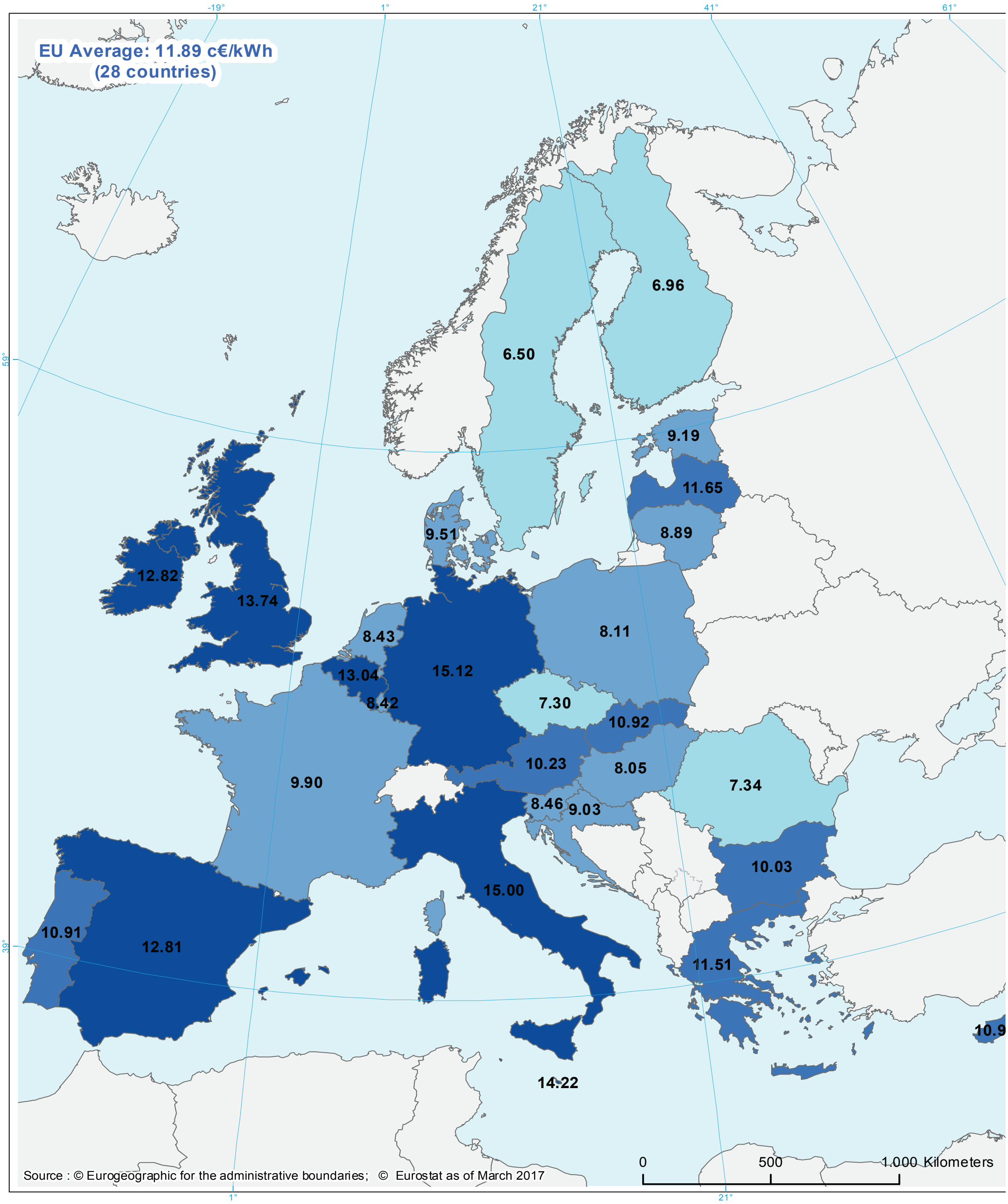
Source: Vaasaett

FIGURE 42 – ELECTRICITY PRICES (INCLUSIVE OF TAXES) – HOUSEHOLDS – ESTIMATED FOR THE FOURTH QUARTER OF 2016



Source: data computed from Eurostat half-yearly retail electricity prices and consumper price indices

FIGURE 43 – ELECTRICITY PRICES (WITHOUT VAT AND NON-RECOVERABLE TAXES) – INDUSTRIAL CONSUMERS – ESTIMATED FOR THE FOURTH QUARTER OF 2016



Prices in Eurocents/kWh

- no data
- <= 8.00
- 8.01 - 10.00
- 10.01 - 12.00
- > 12.00

Excluding VAT (value added tax) and other recoverable taxes

Band IC: 500 MWh < Consumption < 2 000 MWh

7. Glossary

Backwardation occurs when the closer-to-maturity contract is priced higher than the contract which matures at a later stage.

Clean dark spreads are defined as the average difference between the price of coal and carbon emission, and the equivalent price of electricity. If the level of dark spreads is above 0, coal power plant operators are competitive in the observed period. *See dark spreads.*

Clean spark spreads are defined as the average difference between the cost of gas and emissions, and the equivalent price of electricity. If the level of spark spreads is above 0, gas power plant operators are competitive in the observed period. *See spark spreads.*

Contango: A situation of contango arises in the when the closer to maturity contract has a lower price than the contract which is longer to maturity on the forward curve.

Cooling degree days (CDDs) are defined in a similar manner as Heating Degree Days (HDDs); the higher the outdoor temperature is, the higher is the number of CDDs. On those days, when the daily average outdoor temperature is higher than 21°C, CDD values are in the range of positive numbers, otherwise CDD equals zero.

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. Dark spreads are given in this publication for UK and Germany, with the coal and power reference price as reported by *Platts.*

Flow against price differentials (FAPDs): By combining hourly price and flow data, 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 electrical systems.
With the closure of the day-ahead markets (D-1), the prices for each hourly slot of day D are known by market participants. Based on the information from the power exchanges of two neighbouring areas, market participants can establish hourly price differentials. Later in D-1, market participants also nominate commercial schedules for day D. An event named 'flow against price differentials' (FAPD) occurs when commercial nominations for cross border capacities are such that power is set to flow from a higher price area to a lower price area. The FAPD chart in this quarterly report provides detailed information on adverse flows, presenting the ratio of the number of hours with adverse flows to the number of total trading hours in a quarter.

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 to heat a building.

Spark spreads are reported as indicative prices giving the average difference between the cost of natural gas delivered ex-ship and the power price. As such, they do not include operation, maintenance or transport costs. Spreads are defined for a gas-fired plant with 50 % efficiency. Spark spreads are given for UK and Germany in this publication, with the gas and power reference price as reported by *Platts.*

Tariff deficit expresses the difference between the price (called a tariff) that a *regulated utility*, such as an electricity producer is allowed to charge and its generation cost per unit..