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Commission européenne, B-1049 Bruxelles / Europese Commissie, B-1049 Brussel – Belgium

E-mail: ENER-MARKET-OBSERVATORY-QUARTERLY-REPORTS@ec.europa.eu
QUARTERLY REPORT ON EUROPEAN ELECTRICITY MARKETS

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HIGHLIGHTS OF THE REPORT

- In April 2018 the share of renewable sources in the EU electricity generation rose to 38%, being the highest ever, owing primarily to good hydro and wind generation in most of Europe.

- Average wholesale electricity prices at EU level stood at 44 €/MWh in the second quarter of 2018, which was comparable with the average of the previous quarter, but up by 18% in year-on-year comparison.

- In April 2018 however, the weather was milder than usual, contributing to decreasing residential demand for electricity and low monthly wholesale electricity prices in most of Europe. In contrast, high temperatures in June 2018 increased demand for electricity and wholesale prices in many southern and eastern European countries.

- Economic growth continued in Q2 2018 in the EU and GDP grew by 2.1% in year-on-year comparison in the EU, while electricity consumption grew only moderately, by 0.3%.

- Among factors impacting electricity generation costs, natural gas prices increased slightly over Q2 2018, but were up significantly in year-on-year comparison, getting support from bigger injection needs in storages after the depleting impact of cold March weather, and from rising oil and carbon prices. Coal prices rose significantly over Q2 2018, owing to strong global demand for coal, especially in the Asian markets.

- Carbon prices kept on increasing in Q2 2018, however, in June market sentiment on trade issues between the EU and US weighed on the carbon price, as potential US tariffs on carbon intensive industries might reduce their output and demand for emission allowances.

- In consequence, coal and gas consumption in power generation in the EU fell further in Q2 2018, as increasing coal, gas and carbon prices did not contribute to any improvement in the profitability of fossil fuel technologies.

- Retail electricity prices for household customers increased by 4.5% in June 2018 in year-on-year comparison in the European capital cities on average, mainly driven by energy supply and network costs.
EXECUTIVE SUMMARY

- In the second quarter of 2018 the European benchmark day-ahead baseload wholesale electricity price index stood at 44 €/MWh on average, comparable with the average of Q1 2018 (45 €/MWh), but 18% higher in year-on-year comparison, up from 37 €/MWh in Q2 2017. Although quarterly price averages range from 34 €/MWh, measured in Bulgaria to 60 €/MWh in the UK, the overall wholesale price dispersion across different markets in Europe was lower in Q2 2018 than in the few previous quarters.

- Economic growth continued in second quarter of 2018 in the EU and GDP grew by 2.1% in year-on-year comparison, down from the growth measured in the previous quarter (2.4%) and showing the third quarterly growth rate deceleration in a row. Electricity consumption in Q2 2018 in the EU showed only a slight increase in year-on-year comparison (0.3%).

- In April 2018 weather was milder than usual in most of the European continent, implying that heating-related demand for electricity remained moderate, and this contributed to low wholesale electricity prices in most of the markets. In June 2018 temperatures in many southern and eastern European countries were higher than usual, resulting in higher residential demand for electricity that impacted the wholesale electricity markets.

- Natural gas prices on the major European hubs showed a slight increase over the second quarter of 2018, getting support from strong injection needs in the storages after the depleting impact of the cold snap in March at the end of the heating season. Furthermore, rising oil prices also gave a support to the increase in natural gas prices. In year-on-year comparison natural gas prices went up significantly in Q2 2018, owing to the higher demand stemming from bigger storage injection needs. Coal prices underwent a significant increase in the second quarter of 2018, primarily owing to strong global demand for coal in the Asian markets.

- Carbon prices continued their upward trend in Q2 2018 and at the end of May 2018 they rose above 16 €/tCO₂e. As market players priced in the changes in the Market Stability Reserve (MSR) of the European Emission Trading System, which is supposed to reduce the current oversupply in the emission allowance market as of 2019. However, in June 2018 the increase in carbon prices arrived at a temporary halt, as the market was impacted by trade issues between the EU and the US, assuming that potential US import tariffs would negatively impact the production in carbon intensive industries and thus the demand for emission allowances.

- Profitability of coal-fired generation, as a result of increasing coal and carbon prices, could not return to positive ranges in most of the EU countries. Consumption of coal in the power sector decreased in year-on-year comparison. The profitability of gas-fired generation could improve in some continental markets, however, clean spark spreads remained in the negative ranges, and gas consumption in electricity generation decreased further in the EU. Nuclear generation in Q2 2018 decreased in most of countries compared to the previous quarter, as this period of the year is the usual planned maintenance and refuelling period in nuclear power generation.

- In April 2018 the share of renewable sources reached 38% in the EU power generation, being the highest since the beginning of the available time series. In Germany at the beginning of May 2018 the share of renewables reached 55% on weekly average in the electricity generation mix. Beside strong wind generation and increasing solar during longer spring daylight hours, increasing hydro generation in many European markets contributed to this high share of renewable sources.

- Retail electricity prices for household customers increased by 4.5% in June 2018 in year-on-year comparison in the European capital cities on average. Changes in retail electricity prices were mainly driven by increasing energy and supply costs and transmission and distribution costs, but energy taxes also had an upward impact on the final retail prices.
1 Electricity market fundamentals

1.1 Demand side factors

- In the second quarter of 2018 economic growth in the EU-28 continued to decelerate for the third consecutive quarter, and GDP grew by 2.1% in year-on-year comparison as opposed to the growth of 2.3% in Q1 2018. In Q2 2018, according to the data of the European Network of Transmission System Operators (ENTSO-E), consumption of electricity in the EU-28 showed a slight decrease (by 0.3%, or 3 TWh) in year-on-year comparison. Gross value added in important energy consumer sectors, such as manufacturing and construction, was up by 2.7% and 3.5% respectively, if compared to Q2 2017. However, sluggish demand in other sectors, such as the residential sector, might have contributed to the limited increase in electricity consumption in Q2 2018.

Figure 1 – EU 28 GDP Q/Q-4 change (%)

- Figure 2 shows the monthly deviation of actual Heating Degree Days\(^1\) (HDDs) and Cooling Degree Days (CDDs) from the long term averages in the second quarter of 2018 in the twenty-eight Member States of the EU. In April 2018 the weather was generally milder than usual in almost all EU countries, putting a lid on heating related energy needs and on wholesale electricity prices. In May, albeit the heating season was over, temperatures were still higher on average across the EU. In June, as the summer period started, in some countries (e.g.: Spain, Portugal, Greece) temperatures were higher than the long term seasonal average, resulting in increasing cooling needs. More details on regional wholesale electricity markets can be found in Chapter 3.

\(^1\) Please refer to the Glossary for the precise meaning of the terms used in the report
1.2 Supply side factors

- Spot coal prices on Figure 3 (as represented by CIF ARA contracts, the most commonly used import price benchmark in North-Western Europe), showed, after the measurable decrease in Q1 2018 (week 1-13 on the charts), an upturn in the second quarter of 2018 (week 14-26), rising above 80 €/Mt by the end of June. Prices on the global coal market received support from the strong demand in Asia, primarily owing to increasing coal consumption in power generation in China and India. Demand for coal decreased in electricity production in Europe, in parallel with increasing share of renewables and the lower demand for power.

- Spot natural gas prices (represented by Title Trading Facility – TTF in the Netherlands, being the most liquid hub in North-Western Europe) were moderately rising in the second quarter of 2018, ranging between 19 €/MWh and 23 €/MWh. In the first half of Q2 2018 both the mild weather across Europe and the abundant renewable generation put a lid on demand for natural gas in power generation and residential heating. However, compared to Q2 2017, gas hub prices in Europe were measurably higher, primarily owing to the strong injection needs in gas storages after the depleting impact of the cold period in March 2018, and to rising oil prices, which also put an upward pressure on oil-indexed gas contracts.

- Year-ahead coal prices were in backwardation to spot contracts, reflecting lower future price expectations on the coal market. By the end of Q2 2018 the difference between spot and year-ahead coal price contracts rose to 10-12 €/MWh. Difference between spot market and year-ahead gas prices remained negligible over the whole second quarter of 2018, reflecting the low price volatility on the European wholesale gas markets.

- Emission allowance prices kept on increasing in the second quarter of 2018 (see Figure 4) and by the end of May 2018 they rose above 16 €/tCO₂e, up from 13 €/tCO₂e at the beginning of April. The main factor supporting further increases in the carbon price was the anticipation of the regulatory changes with the entry into force of the Market Stablility Reserve mechanism (January 2019). However, in June 2018 the upward price trend was temporary interrupted and prices slightly dropped back. According to market players some general economic issues, such as trade tensions between the EU and US that impacts the CO₂ emission of the sectors concerned, weighed on future demand of emission allowances and thus on carbon prices. Anticipation of higher renewables and energy efficiency targets in EU energy and climate policies also had a lowering impact on projections of demand for emission allowances in the future.

Figure 3 – Weekly evolution of spot and year-ahead coal and gas prices

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2 See more in Quarterly Report on European Gas Markets, Volume 11, issue 2
3 See more in Quarterly Report on European Electricity Markets, Volume 11, issue 1
Coal is represented by CIF ARA, Principal coal import price benchmark in North Western Europe (in €/Mt).

Gas is represented by TTF hub - the Title Trading Facility (NL) gas spot price (in €/MWh).

**Figure 4 – Evolution of free emission allowance spot price**

![Graph showing the evolution of free emission allowance spot price](image)

Source: Platts

**Figure 5** reports on the major extra-EU hard coal (including both steam and coking coal) import sources and the monthly amount of imported coal in the EU. In the second quarter of 2018 coal imports from outside the EU reached 34,100 Mt, which was practically the same amount as in Q2 2017. Compared to the second quarter of 2016 coal imports were slightly up by 6%, but fell by almost 20% if we compare to the same period of 2015. The longer term decreasing trend can largely be linked the dwindling use of coal in power generation in Europe, but coal consumption as whole also shows a generally decreasing trend in the EU.

In the second quarter of 2018 the largest share of extra EU coal imports came from Russia, with a share of 44% in the total, comparable with the import share in Q2 2017 (43%). Russian coal imports were the most competitive extra-EU sources over the last few quarters, probably owing to favourable shipment costs. The second most important import coal import source was the United States, whose share in the total imports reached a four-year high (20%) in Q2 2018, followed by Australia (12%) that pushed back Colombia to the fourth place (slightly less than 12%) and All other import sources had a share below 5% in this period, such as Indonesia (4%), Canada (3%) and South Africa (2%).

In Q2 2018 the estimated EU import bill of hard coal from extra-EU sources amounted to €3.7 billion, while in the second quarter of 2017 the extra-EU import bill was also €3.7 billion, showing the stability of both average coal prices and imported coal amounts in year-on-year comparison.
Figure 5 – The most important extra-EU hard coal import sources and monthly imported quantity in the EU-28

2 European wholesale electricity markets

2.1 Comparisons of European wholesale electricity market and international peers

- As the next map (Figure 6) shows, there were significant price differences in the wholesale electricity prices across the EU in the second quarter of 2018. More details on the drivers behind price changes in each market can be found in Chapter 3.

- The highest quarterly average wholesale electricity prices in the EU could be observed in Q2 2018 in the United Kingdom (60 €/MWh), Greece (56 €/MWh), Ireland (55 €/MWh) and Italy (54 €/MWh). In contrast to the quarterly prices prior to this year, when market prices in the Scandinavian countries were the lowest in Europe, in Q2 2018 the lowest quarterly wholesale averages could be found in Bulgaria (34 €/MWh), Germany and Austria (both 36 €/MWh).

- Among the observed European countries, Norway and Switzerland, both European countries outside the EU, had quarterly wholesale average prices of 39 €/MWh and 37 €/MWh, respectively, which were lower than the EU average, similarly to Serbia (40 €/MWh).

- In the second quarter of 2018 wholesale baseload electricity prices reached 44 €/MWh (European Power Benchmark) on average in Europe, which represented an increase of 18% in year-on-year comparison. Comparing with Q2 2017, in the second quarter of 2018 prices increased by the most in Poland (39%) Denmark (38%) and Estonia (37%), whereas the biggest decreases could be observed in Romania (10%), Bulgaria and Croatia (both 4%).
Figure 6 – Comparison of average wholesale baseload electricity prices, second quarter of 2018

Source: European wholesale power exchanges
In the second quarter of 2018 wholesale day-ahead electricity prices showed an increase in most of the European electricity regions, and in June the European Benchmark Index reached 48 €/MWh on average, which was measurably higher than in April 2018 (39 €/MWh). Prices in the Nordpoolspot\(^4\) market rose to 45 €/MWh in June 2018, to the highest June average price since 2011. Prices in both the Iberian-peninsula and Greece rebounded in Q2 2018 after the significant decrease in the first quarter of 2018. Wholesale prices in Central Western Europe\(^5\) (CWE) showed a measurable discount to the European Power Benchmark (EPB), while the regional price in Central Eastern Europe\(^6\) (CEE) followed closely the European benchmark. The UK has retained its price premium to the continental North Western Europe, and remained the most expensive wholesale electricity market in Europe in Q2 2018.

Figure 7 shows the European power benchmark index and as the two lines of boundary of the shaded area the lowest and the highest regional prices in Europe, as well as the relative standard deviation of the regional prices.

Both the shaded area with minimum-maximum differentials and the relative standard deviation metric show that in June 2018 wholesale electricity prices across different regional markets in Europe reached the highest degree of convergence since several years (the standard deviation was the lowest since mid-2011, and the price differential fell below 18 €/MWh). However, over the last few years, price convergence across the EU mainly occurred in the period of higher prices in the Nordic market, primarily owing to lower hydro generation, and was not always related to increasing cross border electricity flows and better market integration.

Figure 7 – The evolution of the lowest and the highest regional wholesale electricity prices in the EU and the relative standard deviation of the regional prices

![Figure 7](image)

Source: Platts, European power exchanges – As of January 2017 Platts PEP has been replaced by a calculated EU average (European Power Benchmark). In different periods minimal and maximum prices may refer to different power regions.

Figure 8 shows the evolution of the European Power Benchmark (EPB) spot wholesale electricity price contract, as well as the German day-ahead baseload and year-ahead contracts (Germany is one of the most liquid markets in Europe with available forward curve price quotations). Both day-ahead EPB and German baseload contracts show the impact of increasing spot fossil fuel prices (mainly coal prices) in May–June 2018, whereas year-ahead German wholesale electricity prices remained more stable over the whole Q2 2018.(see Figure 3). However, the track of increasing year-ahead coal and gas prices can also be seen in the slight increase in the year-ahead wholesale electricity price.

\(^4\) Nordpoolspot includes Denmark, Estonia, Finland, Latvia, Lithuania, Norway and Sweden

\(^5\) Central Western Europe includes Austria, Belgium, France, Germany, the Netherlands and Switzerland

\(^6\) Central Eastern Europe includes Czech Republic, Hungary, Poland, Romania, Slovakia and Slovenia
10

Figure 8 - Weekly evolution of year-ahead German wholesale electricity prices, compared with coal and gas year-ahead contracts

![Weekly evolution of year-ahead German wholesale electricity prices, compared with coal and gas year-ahead contracts](chart)

Source: Platts and DG ENER
EPB7 - European Power Benchmark (in €/MWh) is the replacement of the Platts PEP as of January 2017. See more detailed description in the Glossary.

- The next chart shows the evolution of the electricity generation mix in the EU-28. Compared to the same quarter of the previous year, in Q2 2018 the share of fossil fuels (combined share of solid fuels and gas) decreased from 33% to 30%, while the share of renewables (hydro, biomass, wind and solar) rose from 32% to 37% on average. The share of nuclear slightly decreased, from 28% to 27%. These changes resulted in a shift towards generation technologies with lower marginal generation costs in the second quarter of 2018 in the EU electricity mix. However, this was counter-balanced by increasing fossil fuel prices, impacting marginal power generation costs and thus wholesale electricity market prices.

Figure 9 – Weekly electricity generation mix in EU-28 in the second quarter of 2017 and 2018

![Weekly electricity generation mix in EU-28 in the second quarter of 2017 and 2018](chart)

Source: ENTSO-E

- Figure 10 shows the evolution of the monthly renewable generation in the EU, in parallel with the share of renewables in the total electricity generation mix. In April 2018 the combined share of renewables (hydro, biomass, wind and solar) reached 38% in the EU electricity mix, being the highest since the beginning of the available time series. In April and May 2018 the total renewable generation in the EU was above 80 TWh, being 1.5 – 2 times as high as the annual electricity consumption of a country like the Czech Republic and Hungary. However, high share of renewable generation, which can also be followed on Figure 9, was largely due to the uptick of hydro power, as with the exception of the Nordic region hydro availability was good in Q2 2018 compared to the previous quarters.
In the following part the profitability of gas-fired and coal-fired electricity generation is analysed by looking at the spread indicators on selected European wholesale electricity markets. In April-May 2018 wholesale electricity and natural gas prices in the United Kingdom showed a slight increase over time, in parallel with rising carbon prices (while in June 2018 wholesale electricity, gas and carbon prices all fell back). In consequence, clean spark spreads remained relatively stable in Q2 2018, ranging between 5-6 €/MWh, implying that gas fired electricity generation in the UK still remained profitable - see Figure 11. At the same time in Germany, where wholesale electricity prices were significantly lower compared to the UK, the profitability of gas fired generation deteriorated further in April and May 2018. In June however, primarily owing to the sharp upturn in the German wholesale electricity price, the clean spark spread increased but remained in the negative range (~4 €/MWh on monthly average).

Most of the European markets in Central and Eastern Europe might have faced clean spark spreads being in the negative range, similarly to the German metric, primarily depending on the local wholesale electricity price, having in most cases a slight premium to Germany.

Figure 11 – Evolution of clean spark spreads in the UK and Germany, and electricity generation from natural gas in the EU
The profitability of coal-fired generation fell deeply in the negative ranges in both Germany and the UK in the second quarter of 2018, as the result sharply increasing coal prices and moderately increasing carbon prices, as Figure 11 shows. In Germany in April and May 2018 clean dark spreads fell into the range of minus 8-9 €/MWh, which has not been seen since the beginning of the available time series (2010). In June 2018 the profitability of coal-fired generation improved owing to rising wholesale electricity prices, however, in the UK it deteriorated further, as the rise in coal price outpaced the increase in the UK wholesale electricity price. In the UK the carbon tax also plays an important role on the top of carbon price, making coal-fired generation much more costlier. Coal-fired generation might have been operated with negative or at best limited profitability in most of the European countries in Q2 2018, bearing in mind the local wholesale price premiums to Germany.

In parallel with decreasing profitability of gas-fired generation in year-on-year comparison, in the second quarter of 2018 electricity generated from gas in the EU-28 fell to 87 TWh, being 6% lower than in Q2 2017. As in year-on-year basis the profitability of coal-fired generation also decreased in Q2 2018, electricity generated from coal fell to 47 TWh, being 12% lower in the second quarter of 2017.

**Figure 12 - Evolution of clean dark spreads in the UK and Germany, and electricity generation from coal in the EU**

The next chart (Figure 13) shows the monthly frequency of occurrence of negative hourly wholesale electricity prices in some markets, where this phenomenon is the most frequent in the EU. Negative hourly prices usually appear when demand for electricity is very low (e.g.: on Sundays or during longer public holidays, such as Christmas, Easter, Labour Day or Pentecost) and when variable renewable generation (wind and solar) is abundant, combined with ongoing relatively non-flexible baseload power generation (e.g.: nuclear). Negative hourly prices are not beneficial for electricity producers, as during these periods they have to practically pay to market actors to buy the generated electricity, resulting in welfare losses.

As it can be followed on the chart, the number of hours with negative wholesale prices in Q2 2018 was lower than in the previous quarter. Most of hourly negative prices occurred on 1 May 2018 and during the long Pentecost weekend (19-21 May) In this month the highest number of negative hourly prices (31) in the EU could be observed in Germany. In April there were only few hours with negative prices on the European wholesale electricity markets, while in June there were none.

Negative hourly prices call for better integration of variable generation sources in the grid and for a market design and infrastructure that enables flows of electricity between neighbouring markets, avoiding local oversupply and excessive demand situations.

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7 The amount of electricity generated from coal does not include lignite fired generation
As Figure 14 shows, in the second quarter of 2018 the gap between wholesale electricity prices in Europe and the US remained stable, showing a slight increase in both markets. On average US quarterly wholesale electricity prices were 45% lower than the EU benchmark index (otherwise saying, the EU-US price ratio was 1.8).

After lower prices in April 2008, wholesale electricity prices in Japan showed a significant increase in May 2018, reaching 95 €/MWh and remaining at this level in June as well. This increase might have been related to increasing LNG import landed prices. In Australia wholesale prices rose again above the EU peers; reaching 60 €/MWh in June 2018, a similar magnitude to that in June 2017.
2.2 Traded volumes and cross border flows

- Figure 15 shows the monthly evolution of electricity traded volumes, including exchange-executed trade and over the counter (OTC) market trade on the most liquid European hubs. Similarly to the last few years, in Q2 2018 the highest trade volumes could be observed on the German market, followed by the Nordic markets, UK, Italy and France. Traded volume of electricity shows a high degree of seasonality, following the higher consumption during winter periods.

- In the second quarter of 2018 the total monthly traded volume of electricity showed in April 2018 was 925 TWh, in May it went up to 1143 TWh and fell back in June to 989 TWh. In Q2 2018 as a whole, the traded volume of electricity on the observed platforms amounted to 3,056 TWh, up from 2,964 TWh in Q1 2018, representing an increase of 3%, while in year-on-year comparison the total traded volume increased by 10% (from 2,769 TWh in Q2 2017).

Figure 15 – Monthly traded volume of electricity (incl. exchange executed and OTC) on the most liquid European markets

![Monthly traded volume of electricity on the most liquid European markets](image)

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

- Figure 16 shows the comparison of volumes in different market segments of electricity trading on the most liquid electricity trading platforms in the EU. In Q2 2018 in year-on-year comparison the total traded volume of electricity increased by the greatest amount in Germany (by 9% or 144 TWh), Italy (by 45% or 54 TWh) and in the Nordic markets (by 8% or 26 TWh). In contrast, in France traded volume of electricity decreased (by 5% or 11 TWh).

- In different segments of the electricity trade the extent of the decrease in traded volumes was also different. In Q2 2018 the overall traded volume increased by 10% in year-on-year comparison, however, in the case of the over-the-counter (OTC) trade the increase was 8.5%, while the volume of exchange-executed contracts rose by 12.5%.

Figure 16 - Comparison of electricity traded volumes in some important day-ahead, forward and OTC markets, first quarter of 2018

![Comparison of electricity traded volumes in some important day-ahead, forward and OTC markets](image)

Source: Platts, wholesale power markets, Trayport, London Energy Brokers Association (LEBA) and DG ENER computations
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 on the spot and the curve) and electricity consumption in a given time period. Figure 17 shows the evolution of the quarterly regional churn rates between the beginning of 2015 until the second quarter of 2018. In Q2 2018 the quarterly churn rate in the German market rose to 14.6 from 12.9 measured in Q1 2018. In the Nordic markets the churn rate increased from 3.0 to 3.9, while in the UK it went up from 3.0 to 3.7. In Italy and France the churn rate was 2.2 in Q2 2018, while in Central and Eastern Europe it remained lower (1.4).

Figure 17 Quarterly churn rates on selected European wholesale electricity markets

As Figure 18 shows, in the second quarter of 2018 the net exporter position of the Central Western Europe (CWE) power region improved again and in June the net electricity exports rose above 7 TWh. Competitive electricity prices across the region assured good opportunities to export electricity to Italy, the UK, Spain and Central Eastern Europe.

Central Eastern Europe and the Iberian-peninsula increasingly relied on imports in Q2 2018, however, South Eastern Europe’s electricity net export position was lower than in the previous quarter, in spite of good hydro availability across the region.

The Nordic region switched back to net exporter position in Q2 2018, however, prices in June 2018 were high in seasonal comparison, owing to low hydro reserves and power generation, which resulted in lower than usual net exports in this time of the year.

Italy retained its strong net importer position during Q2 2018, however, as renewable generation started to pick up, it had to import less electricity as in the previous quarter. Italy mainly imported its electricity need from Central and Western Europe, the British Isles and the Baltic-states were also net importers in the second quarter of 2018.
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

- Figure 19 shows the ratio of net electricity flow position to the domestic electricity generation in each region. Unlike the previous chart, showing absolute net cross border position numbers, this chart enables cross region comparison of net positions relating to the domestic production, thus eliminating differences in the market size.

- In spite of being significant electricity exporter, the CWE region only exported around 8% of its total production in June 2018. In the same month the CEE region imported an amount corresponding to 9% of its total electricity production.

- Italy (Apennine peninsula) imported 15% of its electricity need on average in Q2 2018. The Baltic region followed the seasonal pattern and in June 2018 it imported almost half of its electricity consumption. In the case of the other regions the net cross border position was less than 10% compared to domestic production.

Source: ENTSO-E, own computations
Regional wholesale markets

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

- In April 2018 the monthly average wholesale baseload electricity price in the CWE region fell to 35 €/MWh from 43 €/MWh measured in the previous month, while the average peakload was 35 €/MWh on monthly average at the beginning of the second quarter of 2018, as Figure 20 shows. As from the next month, both monthly average baseload and peakload contracts rose again and in June the monthly baseload and peakload averages respectively reached to 44 €/MWh and 46 €/MWh.

- The daily average regional day-ahead baseload prices remained well-aligned during most of the time in Q2 2018, as it can be followed on Figure 21. However, the German daily average wholesale price was much lower on some trading days. On 1 May 2018 the average day-ahead baseload price fell below zero (-5.7 €/MWh), and on this day there were 18 hours with negative hourly prices. On 21 May the German daily average price fell to 5 €/MWh, and on this day there were also 10 hours with negative prices. On the other hand, wholesale electricity prices in Belgium and the Netherlands, having a premium over Germany and France during the whole quarter, rose to as high as 67 €/MWh on 31 May 2018.

- As the heating seasons ends in most of the European countries in April-May with the onset of spring, electricity demand decreases compared to the winter period. April 2018 was milder than usual in the CWE countries, and compared to the cold March weather the monthly electricity consumption was down by 10-25% across the region, in the biggest extent in France where residential heating is largely based on electricity. This significant decrease in electricity demand drove down the wholesale prices on the market.

- On the supply side, in Q2 2018 both wind and solar generation in Germany rose compared to the same quarter of the previous year (by 5% and 12%, respectively). In May 2018 renewable sources, including hydro and biomass beside wind and solar, ensured 50% of the German generation mix, while in week 18 this share was 55%, being the highest since ever recorded. However, in June 2018 the combined wind and solar generation fell back by 15% compared to May, leaving a bigger share to fossil fuel generation that resulted in higher wholesale market prices.

- In France nuclear availability in April and May was similar in year-on-year comparison, however, in June 2018 it was significantly better than a year before (see Figure 22), resulting in an increase of 6% of nuclear generation. At the same time in Germany two reactors were taken offline for refuelling, and as other thermal capacities were also off the grid, supply margins tightened, also supporting the increase in the wholesale electricity price. In Belgium significant nuclear capacities were still offline, resulting in significant import needs from France.

- In May and June 2018 hydro generation in France was up by 45% and in Germany it increased by 20% in year-on-year comparison. This was helped by the melting snow in the higher regions of the Alpes. However, in France and Switzerland hydro reserve levels remained low in seasonal comparison during almost all of Q2 2018. Cheap hydro generation enabled France to export significant amount of electricity to its neighbours, and in May 2018 its net electricity export was higher than 8 TWh, last seen in 2014.

- The increase in the wholesale electricity prices across the CWE region in May-June 2018 was helped by increasing coal, gas and carbon prices, resulting in higher marginal power generation costs. As it was mentioned before, in June 2018 the share of renewables fell back in the regional generation mixes, providing for higher share of costlier generation sources that supported a further increase in the wholesale electricity prices.
Figure 20 - Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Central Western Europe

Source: Platts, EPEX

Figure 21 – Daily average wholesale power prices in the CWE region

Source: Platts.
3.2 British Isles (UK, Ireland)

- Wholesale electricity prices in the UK and Ireland started the second quarter of 2018 lower than they were in March: the average April 2018 baseload price in the UK stood at 58 €/MWh, while in Ireland it was 53 €/MWh. As of May however, the monthly averages showed a slight increase, and by June 2018 the UK and Irish monthly price averages respectively rose to 62 €/MWh and 57 €/MWh (see Figure 23). Looking at the daily averages, wholesale electricity prices in the UK varied between 54 €/MWh and 69 €/MWh, while in Ireland they fluctuated in a range of 43 €/MWh and 72 €/MWh.

- Wholesale electricity prices in the UK moved in parallel with increasing natural gas prices in the NBP hub in April and May 2018. As during this time the NBP hub price rose from 19 €/MWh to 23 €/MWh UK daily average price rose from 57 €/MWh to 68 €/MWh until the end of May. Then in June 2018 both the natural gas price and the wholesale electricity price went down (see Figure 24). Irish prices did not show so close co-movement with natural gas hub prices, as in this country other generation sources, such as wind and oil significantly impacted the marginal power generation costs.

- Wind and solar ensured more than one fifth of the UK’s electricity generation in the second quarter of 2018. However, as of the second half of May 2018, as Figure 25 shows, the share of wind fell back in the generation mix, leading to higher share of natural gas, which also contributed to the increase of the wholesale electricity price in the market. The role of coal remained limited in the UK power mix in Q2 2018, ensuring less than 2% of the total generation. It seems that the role of coal in UK generation has been reduced to seasonal character, it is only important during wintertime. In Ireland wind generation also retreated in May and June from the high April levels (when wind ensured around one third of the Irish generation mix), and the contribution of gas and oil increased in the power mix, driving up the wholesale prices in the country.

- During the whole Q2 2018 the UK retained its price premium over the continental markets (23 €/MWh over France and 16 €/MWh over Netherlands). Even with increasing renewable generation electricity import still remains a competitive alternative in the UK, as natural gas has a large share and it manages to set the marginal generation costs and the wholesale electricity price.
Figure 23 – Monthly electricity exchange traded volumes and average day-ahead wholesale baseload prices in the UK and Ireland

Source: Nordpool N2EX, SEMO

Figure 24 – Daily average baseload electricity prices in the UK and Ireland

Source: Nordpool N2EX, SEMO
3.3 Northern Europe (Denmark, Estonia, Finland, Latvia, Lithuania, Norway, Sweden)

- In April 2018 the monthly average wholesale electricity system baseload price in the Nordpoolspot market decreased from the March level, as harsh winter conditions were over and demand for heating related electricity went down. In this month the daily average price was 39 €/MWh, then in May it fell to 34 €/MWh and in June it turned up to 45 €/MWh, as it can be followed on Figure 25. The June average Nordpoolspot system price was the highest June monthly since 2011.

- The combined hydro reserve levels in April 2018 in Norway, Sweden and Finland were lower than in the preceding five years, but in May and June they started to increase and returned to the usual seasonal ranges. Interestingly, generation from hydro power did not follow the improving hydro reserve levels but remained very low compared to the last five years. Electricity production in Norway (of which more than 95% is ensured by hydro sources) can be followed on Figure 27, showing that especially in June the production was below the range of 2013-2017.

- In June 2018 hydro generation also fell back, both in month-on-month and year-on-year comparison in Sweden and Finland. In both countries increasing nuclear generation could partially compensate missing hydro power, however, as wind and biomass based generation also fell back across the region compared to the previous year, in order to satisfy domestic consumption needs, export of electricity had to be decreased in this month. The Nordic region, after high March prices, was still in net electricity importer position in April, in May it switched to net exporter but in June 2018 it became close to export-import equilibrium due to decreasing exports.

- The impact of low generation of competitive hydro power can also be followed on the chart showing the daily average regional prices (Figure 28) in the Nordpoolspot market region. Prices in the Baltic-states were prone to show sudden spikes in the second half of Q2 2018. For example, in Lithuania the local market price rose to 100 €/MWh on 16 May 2018. Albeit improving electricity interconnection capacities over the last few years, if the abundance of electricity supply in the Nordic market is lower than usual (e.g.: turning into net electricity importer), the eastern part of the Nordic region had normally a measurable price premium to the Nordpoolspot system price.
Figure 26 - Monthly electricity exchange traded volumes of and the average day-ahead wholesale prices in Northern Europe

Figure 27 – Weekly electricity generation in Norway in 2018, compared to the range of 2013 to 2017
3.4 Apennine Peninsula (Italy)

- The Italian wholesale baseload electricity price, (see Figure 29) showed a moderate increase over the second quarter of 2018: in April 2018 the monthly average baseload contract was 49 €/MWh, rising to 53 €/MWh in May and 57 €/MWh in June. However, this gradual increase practically meant a rebound to the average price of March, as in April with the onset of spring electricity demand and wholesale prices followed the usual seasonal decrease.

- Daily average wholesale electricity prices showed a high degree of stability in Q2 2018, ranging between 41 €/MWh and 61 €/MWh. In April the daily average prices followed a slightly decreasing trend, while from May they started to increase and rose until the end of the quarter.

- Hydro power generation in Italy rose significantly, by 60 % in the second quarter of 2018 in year-on-year comparison and ensured 27% of the Italian electricity generation mix in this quarter. Wind generation remained stable in year-on-year comparison, and both natural gas and solar production slightly decreased. Beside hydro only coal-fired generation managed to increase its share in Q2 2018, if compared to the previous year.

- Spot natural gas prices on the Italian PSV hub showed a slow but steady increase over time in Q2 2018, starting the quarter at 21 €/MWh and finishing it above 24 €/MWh. As it was presented in Chapter 1.2, coal prices also increased during this quarter, resulting in higher generation costs. However, as hydro generation underwent a significant increase, it mitigated the impact of increasing fossil fuel costs. Although average daily temperatures in June 2018 were higher than the seasonal average during most of the time, the wholesale market did not seem to be impacted by any incremental heating related demand for electricity.

- As Figure 30 shows, regional area prices in Italy remained well-aligned to the national system price during most of the time in Q2 2018, there were only few occasions, when in a given region the daily average price showed a sudden rise (for example on 10 May 2018 the Sicily area price reached 101 €/MWh, and in mid-June 2018 in some foreign virtual zones the area price was even higher). During the summer period prices in Italian island areas prone to show sudden spikes, pointing to the need for enhancing interconnections with mainland Italy.
In the second quarter of 2018 the monthly average wholesale baseload contracts in Spain and Portugal underwent a significant increase: while in April both the Spanish and Portuguese contract was below 43 €/MWh, in June 2018 they rose to 59 €/MWh. Meanwhile the peakload monthly average in Spain increased from 43 €/MWh to 59 €/MWh and in Portugal it went up from 46 €/MWh to 61 €/MWh, (see Figure 31).

Figure 32 shows the evolution of the weekly electricity generation mix in Spain. At the beginning of the second quarter of 2018 (week 14) the combined share of renewable energy sources, namely hydro, wind, solar and biomass, was nearly 60%, at the end of the quarter (week 26) the share of renewables fell to 38%, following the general trend of decreasing wind and hydro availability in Europe after the abundance in April 2018. The share of coal and gas went up from 19% to 39% between the first and the last week of Q2 2018. In Portugal the share of renewables in the electricity generation mix amounted to 81% in April 2018, while the share of coal and gas was 18%; in June these two shares were respectively 44% and 54%.

This significant shift towards fossil fuels in the Spanish and Portuguese generation mixes over the course of the second quarter of 2018 resulted in higher generation costs through the merit order effect, which gave an upward
support to the wholesale electricity price. It is worth recalling that in Q2 2018 both coal and gas prices increased in many European markets, resulting in an additional pressure on electricity generation costs from fossil fuel sources.

- Nuclear generation in Spain in the second quarter of 2018 fell by 13% in year-on-year comparison. This was a large extent due to simultaneous outages of several nuclear capacities (e.g.: the extended outage for refuelling purpose of Vandellos-2 nuclear reactor, started back in Q1 2018, from mid-April Almaraz-2 was taken offline and remained unavailable until the end of Q2 2018 and at the end of May Asco-2 went off the grid for a week). At the end of May 2018 nuclear availability fell to 4 GW, being 3 GW lower than the total available capacities in Spain.

- At the beginning of the second quarter of 2018, as Figure 33 shows, Spain switched back to net electricity importer position with France, after the end of cold weather in Western Europe and high wholesale electricity prices in March 2018. Due to the rapidly increasing Spanish wholesale prices, the Iberian market reached a premium of 16 €/MWh to France in June 2018.

Figure 31 - Monthly electricity exchange traded volumes and average day-ahead prices in the Iberian Peninsula

![Figure 31](image)

Source: Platts, OMEL

Figure 32 – Weekly evolution of the electricity generation mix in Spain in the second quarter of 2017 and 2018

![Figure 32](image)

Source: ENTSO-E
Figure 33 – Weekly electricity flows between France and Spain and price differentials between the two markets

Source: ENTSO-E, OMEL, Platts

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

- The regional average wholesale price contracts in Central and Eastern Europe (CEE) increased measurably between April and June 2018. The monthly regional average baseload price rose from 35 €/MWh to 49 €/MWh in this period, while the monthly peakload average went up from 39 €/MWh to 61 €/MWh, as Figure 34 shows. The regional weighted average of daily baseload price reached its trough on 1 May 2018 (Labour day) at 9 €/MWh (on this day the daily average price in Czech Republic and Slovakia fell below zero), and its peak (56 €/MWh) on 30 May 2018.

- Generally mild weather in April 2018 across Europe also impacted the CEE region and resulted in lower than usual heating needs and thus residential demand for electricity. In contrast, during the first three weeks of June 2018 at the beginning of the summer daily average temperatures in the countries of the region were higher by 2-8°C compared to the long term seasonal averages, resulting in increasing residential cooling demand and higher prices on the wholesale electricity markets, as Figure 35 shows. High temperatures and low river levels in Poland also put a limit on water cooling of power plants, resulting in reduction of electricity generation.

- On the generation side, nuclear availability in the Czech Republic and Slovakia was higher in Q2 2018 than a year before. However, in May 2018 in Hungary a nuclear reactor with nameplate capacity of 500 MW (belonging to the Paks Nuclear Power Plant) was taken offline and remained off the grid until the end of June 2018. In Poland in May and June there were several outages at the Belchatow lignite-fired power plant and in Hungary a gas-fired plant with 400 MW capacity, and a lignite-fired plant of 200 MW capacity was taken off the grid until the end of Q2 2018.

- Similarly to most of the European markets, wind power generation in the CEE region also decreased in June 2018 compared to the higher production in April and May. Hydro generation in Romania, albeit was higher in Q2 2018 in year-on-year comparison, decreased between April and June 2018. Decreasing wind and hydro generation, coupled with outages in the conventional thermal generation capacities in some countries of the region, resulted in increasing electricity generation costs, contributing to the increase in the wholesale market prices. Electricity imports from the Balkans, meaning competitive alternative for domestic generation in some countries of the CEE region (e.g.: Hungary) also showed a decreasing trend in Q2 2018.
3.7 South Eastern Europe (Bulgaria, Croatia, Greece and Serbia)

- Similarly to most of the European markets, wholesale electricity prices in the South-Eastern Europe (SEE) region increased in the second quarter of 2018. While in April the regional average baseload and peakload contracts stood at 49 €/MWh, in June 2018 both averages were above 60 €/MWh, as it can be followed on Figure 36. Baseload prices were the highest in Greece in the SEE region in Q2 2018, the quarterly average price in Bulgaria had a discount of 22 €/MWh, while in Serbia and Croatia prices were respectively by 15 €/MWh and 13 €/MWh below the Greek contracts.

- Looking at the daily average price contracts (see Figure 37), Greek prices showed a slow increase and were between 50 €/MWh and 60 €/MWh during most of the time the second quarter of 2018. In April and May 2018 baseload prices in Bulgaria, Croatia and Serbia remained well-aligned and followed an increasing trend, from the range of 20-30 €/MWh to 40-50 €/MWh. The steady increase in the regional prices at the beginning of the summer period was also supported by temperatures being several degrees higher than the long term daily averages, resulting in increasing residential consumption (cooling needs).
• In June 2018 Bulgarian prices decoupled from the other regional peers and showed a significant discount to Croatia and Serbia. These lower electricity prices might have been related to increasing nuclear power generation in Bulgaria, as beside domestic lignite-fired generation and hydro sources in the country nuclear can also ensure baseload electricity production with low generation costs. Low electricity prices resulted in increasing Bulgarian exports to the neighbouring countries, mainly to Greece, Serbia and to the Former Yugoslav Republic of Macedonia.

• On the other hand, electricity prices in Greece showed a modest increase, owing to increasing seasonal demand at the beginning of the summer, decreasing hydro generation and increasing gas-fired generation, resulting in higher electricity generation costs. Wind and solar electricity generation did not show big changes in Greece in Q2 2018, ensuring around one fourth of the domestic generation.

Figure 36 – Monthly traded volumes and prices in South-Eastern Europe

![Graph showing monthly traded volumes and prices](image1)

Source: LAGIE, IBEX

Figure 37 – Comparison of weekly average day-ahead prices in Bulgaria, Greece, Romania and Serbia

![Graph showing weekly average day-ahead prices](image2)

Source: IBEX, LAGIE, OPCOM, SEEPEX
Retail markets in the EU and outside Europe

- Figure 38 and Figure 39 show the monthly estimated retail electricity prices in June 2018 in the 28 EU Member States for industrial customers and households, for three different levels of annual electricity consumption for both consumer types (Eurostat bands IB, IC and IF for industrial customers and bands DB, DC and DD for households). In most cases it holds for both consumer types that the lower the consumption, the higher the price of one unit of electricity (per kWh).

- Retail prices paid by households include all taxes, levies, fees and charges. Prices paid by industrial customers exclude VAT and recoverable taxes. Monthly retail electricity prices are estimated by using Harmonised Consumer Price Indices (HICP) based on bi-annual retail energy price data from Eurostat.

- Median industrial consumers (band ID) paid the highest prices in Italy (14.64 Eurocents/kWh), Germany and Ireland (apart from the non-interconnected island systems of Malta and Cyprus). The lowest prices were reported by Sweden (6.12 Eurocents/kWh), Finland and the Czech Republic. The ratio of the largest to smallest reported price was above 2:1. Industrial consumers with large annual consumption (IF), including most energy intensive users, paid the highest prices in the United Kingdom (12.46 Eurocents/kWh), Slovakia and Italy. The smallest prices were reported by Luxembourg (4.04 Eurocents/kWh), Sweden and Finland. The ratio of the largest to smallest reported price was even bigger, around 3:1 for this consumer type.

- In June 2018 Denmark (31.19 Eurocents/kWh) reported the highest median household price for electricity consumers, followed by Germany, Belgium and Ireland, countries surpassing 30 Eurocents/kWh. The smallest prices were reported by Bulgaria (9.83 Eurocents/kWh). Household electricity prices are even more impacted by taxes and levies than their industrial counterparts. The variety and level of taxes and levies differs significantly from country to country, therefore the ratio of largest to smallest price was the highest for this consumer type at above 3:1.

Figure 38 – Estimated industrial retail electricity prices, June 2018 – without VAT and recoverable taxes

Source: Eurostat, DG ENER
Figure 39 - Estimated household retail electricity prices, June 2018 – all taxes included

Source: Eurostat, DG ENER

- Figure 40 and Figure 41 show the convergence of retail prices across the EU over time, by depicting their relative standard deviation. Prices for industrial consumers became more divergent in the second quarter of 2018 compared to the previous quarter of the same year, but converged significantly compared to the second quarter of 2017, indicating progress towards the completion of the single energy market. Price divergence for large industrial consumers (ID) also slightly increased in the second quarter of 2018 after a sharp fall in the beginning of the year.

- The evolution of household price convergence was less volatile. As noted above, household prices are more impacted by regulated elements (network charges, taxes and levies), while industrial price are more impacted by the energy component, which is the only component determined by market forces.

Figure 40 – Relative standard deviation of retail electricity prices in the EU Member for industrial consumers

Source: Eurostat, DG ENER
The two maps (Figure 42 and Figure 43) show the estimated quarterly average retail electricity prices paid by households and industrial customers, with medium level of annual electricity consumption.
Figure 42 - Electricity prices (inclusive of taxes) – Households – Estimated for the second quarter of 2018

Source: Data computed from Eurostat half-yearly retail electricity prices and consumer price indices.
Figure 43 – Electricity prices (without VAT and non-recoverable taxes) – Industrial consumers – Estimated for the second quarter of 2018

Excluding VAT (value added tax) and other recoverable taxes

Band ID: 500 MWh < Consumption < 2 000 MWh

Source: Data computed from Eurostat half-yearly retail electricity prices and consumer price indices
4.1 Retail electricity prices in the EU capital cities

- Figure 44 shows retail electricity prices recorded in European capital cities. In June 2018 the highest prices were observed in Copenhagen and Berlin (31.3 Eurocent/kWh and 30.8 Eurocent/kWh, respectively), much in line with the Eurostat data analysed before. The smallest prices were recorded in Sofia and Vilnius (10.8 Eurocent/kWh and 11.8 Eurocent/kWh respectively) among EU capitals. Compared to the same period of the previous year, the largest price increases are observed in the capitals of Estonia (+20%) and Romania (+19%). In Tallinn prices were driven by the increasing network charges, while in Bucharest the commodity price increased.

Figure 44 – The Household Energy Price Index (HEPI) in European capital cities - Electricity prices in June 2018, and changes in household electricity prices compared to June 2017

![Graph showing electricity prices in June 2018 and changes compared to June 2017](source: Vaasaett)

- Network charges contributed to price increases in several reporting countries while in Cyprus, Portugal and Romania the network component decreased by up to 1%.
- Taxes experienced the highest increases in Croatia, the Netherlands, Romania and the UK. In other countries, such as Austria, Estonia, Greece, Latvia, Luxembourg and Spain taxes decreased compared to the same month of the previous year. The amount of VAT, as an ad valorem tax, follows the aggregate evolution of all other price elements.
- Based on the evolution of the network component, countries form two distinct groups. In the first one the network component remained largely constant compared the same month of the previous year. In the other group, including Estonia, the United Kingdom, Latvia, and Luxembourg the network component increased by up to 2%. Some countries, including Cyprus, Portugal and Romania reported network components lower than in the same month of the previous year.
4.2 International comparison of retail electricity prices

- Figure 46 displays industrial retail prices paid by consumers in the EU and in its major trading partner countries. Prices in the EU remained relatively high, second only to prices in Japan. Differences between wholesale electricity prices in the EU and the US are mirrored by differences between EU and US retail prices. In the case of Japan the decreasing price premium to EU wholesale electricity benchmark can also be tracked in the retail market.

- The evolution of Korean prices remained fairly constant and similar to the evolution of the EU benchmark. The premium of the EU average to Turkish and Mexican prices decreased, as Turkish and Mexican prices increased at a higher rate than its EU counterpart. Over the last few quarters retail electricity prices in China were close to their EU peers.

Source: Eurostat, IEA, CEIC, DG ENER computations
5 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.

European Power Benchmark (EPB7) is a replacement of the former Platt’s PEP index discontinued at the end of 2016, computed as weighted average of seven major European markets’ (Belgium, France, Germany, Netherlands, Spain, Switzerland, United Kingdom) day-ahead contracts.

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.

Long-term average for HDD and CDD comparisons: In the case of both cooling and heating degree days, actual temperature conditions are expressed as the deviation from the long-term temperature values (average of 1975-2016) in a given period.

Monthly estimated retail electricity prices: Twice-yearly Eurostat retail electricity price data and the electricity component of the monthly Harmonised Index for Consumer Prices (HICP) for each EU Member States to estimate monthly electricity retail prices for each consumption band. The estimated quarterly average retail electricity prices on the maps for households and industrial customers are computed as the simple arithmetic mean of the three months in each quarter.

Relative standard deviation is the ratio of standard deviation (measuring the dispersion within a statistical set of values from the mean) and the mean (statistical average) of the given set of values. It measures in percentage how the data points of the dataset are close to the mean (the higher is the standard deviation, the higher is the dispersion). 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.
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.