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Quarterly Report on European Electricity Markets

Market Observatory for Energy

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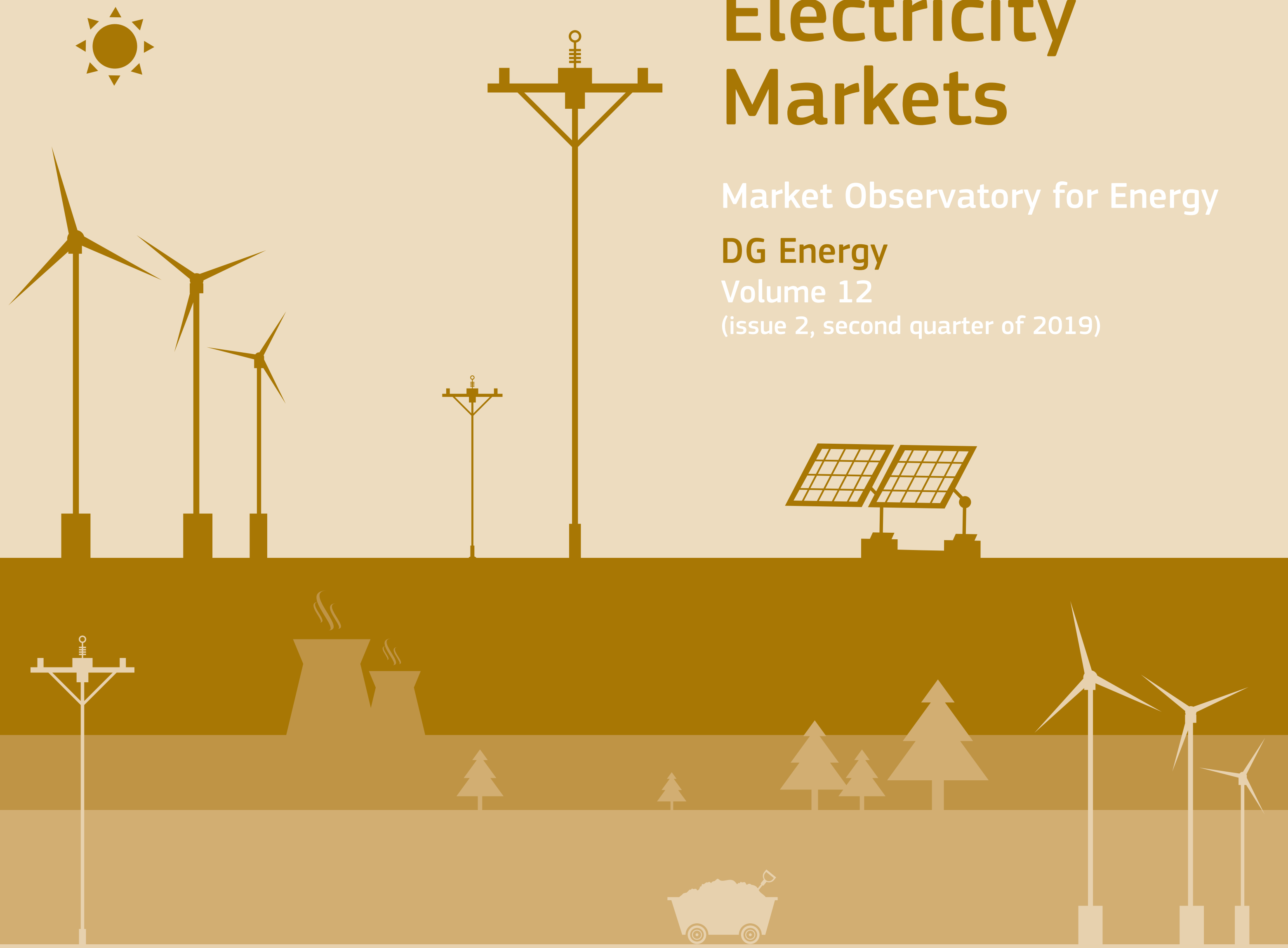

Energy

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CONTENT

HIGHLIGHTS OF THE REPORT

- **Intensive coal-to-gas switching, which gathered pace in the electricity market at the beginning of this year, continued across the EU in Q2 2019 as gas prices headed to multi-year lows thanks to plentiful pipeline supplies and record LNG deliveries and as coal was heavily disadvantaged by rising CO2 prices. In some countries lignite-to-gas switching occurred as well.**

- **While EU-wide coal- and lignite-based electricity generation in Q2 2019 declined by 16% (or 17 TWh) year-on-year, gas-fired power production jumped by 39% (or 34 TWh), displacing coal and mitigating very weak hydro output in Southern Europe. In June, coal and lignite reached their lowest share in the EU power mix on record - 13%.**

- **As a result of its reduced use, thermal coal imports from outside of the EU in Q2 2019 fell by 22% year-on-year to 20.2 Mt, the lowest amount on record. Several retirements of coal units in Western Europe were announced or brought forward in the reference quarter.**

- **The price of emission allowances rose by 20% in the second quarter, braking multi-year highs on its way up. The withdrawal of allowances into the Market Stability Reserve, reduced supply stemming from UK volumes being blocked from entering the market and increased interest of wider investor community influenced price developments. Events surrounding the Brexit issue continued to be a significant factor as well.**

- **The share of renewable energy in the EU power mix reached 35.1% in the reference quarter. This was lower than the 36.6% share from Q2 2018 and was mainly influenced by poor hydro generation. Total combined output of solar, wind and biomass generation in the reference quarter increased by 7.5% year-on-year to 145 TWh.**

- **Wholesale electricity prices fell in most EU markets in Q2 2019 thanks to lower energy commodity prices and increasing renewable output. The European Power Benchmark declined by 19% compared to the previous quarter.**

- **A very rare event of decoupling of several West European day-ahead markets occurred on June 7, distorting cross-border flows and influencing wholesale prices from London to Bratislava that day. The episode, which brought extreme volatility to some markets, demonstrated the possible effects of software failure at one of Europe's most important exchanges.**

- **The varied pace of renewable capacity expansion across the EU, rising CO2 prices, which impact different markets and generation mixes unevenly, and insufficient interconnection capacities were driving up divergence in regional and zonal wholesale prices in Q2 2019. This trend, together with several critical grid situations which occurred in the reference quarter, points to the need for increased investment in strengthening network resilience and expanding cross-border capacities.**

- **The average retail electricity prices for industry in Q2 2019 increased by 0.6% compared to the last quarter. In the case of median households, the largest year-on-year price rises were assessed in Cyprus (+19%), the UK (+15%), Lithuania (+15%), and Finland (+14%), whereas the biggest year-on-year price falls were estimated for Greece (-8%), Denmark and Poland (both -7%)**

EXECUTIVE SUMMARY

- EU-wide electricity consumption in the EU rose by 0.7% year-on-year to 753 TWh in Q2 2019 as increases in some member states slightly outweighed falls in others. Power consumption went up in France (+3.9%), Spain (+2.8%) and Poland (+1%), while decreases were registered in Germany (-1.4%), the UK (-0.8%), and Italy (-0.2%). All three latter mentioned countries experienced negative or zero economic growth in the reference quarter.

- Spot gas prices, measured by the TTF contract, weakened by 37% during the reference period amid stable pipeline flows from Russia, plentiful LNG supply and high storage levels. The TTF contract finished the quarter at 9.30 €/MWh which was 55% lower than at the same time last year and a 10-year low (see Q2 2019 report on EU gas markets for more details). Spot coal prices, represented by the CIF ARA contract, followed a similar path, falling by almost 21% during Q2 2019 and finishing the quarter at 42.18 €/Mt, the lowest level since Q1 2016. High stocks at the Dutch terminals, low demand from generators and falling gas prices (a direct competitor fuel in the European electricity production) continued to depress the market.

- The emission allowance market moved significantly higher, with average spot prices rising by 20% during the reference period. This put further pressure on carbon-intensive generation capacities, especially in the coal-fired sector. At 25.44 €/t, the average price of one allowance in Q2 2019 was more than 75% higher than the average price in the same quarter a year ago (14.50 €/t). Increased trading activity on the secondary market suggests that the carbon market has attracted the attention of a wider pool of participants.

- Rising CO2 prices continued to materially affect electricity production as less CO2-intensive gas generation gained prominence, reaching 18.4% share in the overall EU power mix in Q2 2019 (compared to 13.2% in Q2 2018), at the expense of hard coal and lignite generation, which saw its combined share reduced to 13.9% in the reference quarter (from 16.6% in Q2 2018). In some cases a combination of extremely low gas prices, higher renewable availability (which pushed down power prices) and heightened carbon costs started to seriously undermine the economics of some lignite units, leading to measurable lignite-to-gas switching. The share of lignite in the EU power mix fell to 7.9% in Q2 2019 (from 9.4% in Q2 2018). In Q2 2019 the estimated EU import bill for thermal coal reached €1.7 billion, 22% lower compared to Q2 2018. The amount of imported thermal coal in the reference quarter went down to 20.2 Mt, the lowest quarterly figure on record. The significant fall in coal imports reflects intensive coal-to-gas switching and a decreasing role of coal in the EU generation mix. The largest share of extra-EU thermal coal imports (65%) came from Russia.

- The combined share of hydro, biomass, wind and solar in the EU generation mix reached 35.1% in Q2 2019 (down from 36.6% in Q2 2018). This compares with 21.0% renewable energy share in the power generation of the United States and 23.3% renewable share in the Chinese power mix during the same quarter. The trend of a gradually rising share of renewable generation in the EU was temporarily derailed in Q2 2019 by weak hydro output which declined by 18% compared to Q2 2018. The main drivers were severe droughts in Spain and Portugal and lower reservoir and precipitation levels in France and Italy. The share of hydro generation thus reached 13.2% in Q2 2019, compared to 16.1% in the same quarter last year. In contrast, wind-powered generation recorded a strong second quarter of 2019, gaining a 12.4% share in the overall mix (up from 11.1% in Q2 2018) and becoming the biggest contributor to renewable generation growth. The share of solar generation, at 6.1% (not including some rooftop PV installations), remained unchanged compared to the previous Q2.

- The pan-EU average of wholesale baseload prices reached 43.3 €/MWh in the reference quarter, down 1% in a year-on-year comparison. Matched against the value from Q1 2019, the wholesale benchmark fell by 11.5%. In Q2 2019 the lowest prices could be found Sweden (33.4 €/MWh) thanks to ample local hydro reservoir levels and high generation levels of its fast-growing wind fleet. Wholesale prices in Greece and Poland, in contrast, rose close to 60 €/MWh as high CO2 prices weighed down on their carbon-intensive generation mixes.

- The Central Western European region continued to dominate as the export powerhouse of the continent, having plentiful and diverse generation capacities, competitive prices and a central position suitable to supply all the other regions. Monthly net export flows were relatively stable, adding up to 21.7 TWh for the whole reference quarter (+3% compared to Q2 2018). Italy remained by far the largest importer of electricity in Q2 2019, receiving 8.9 TWh of net inflows. The Nordic region emerged as a net exporter only in the second half of the reference quarter thanks to surging Swedish renewable generation. The position of the Baltic region worsened during the reference quarter as it imported an amount equivalent to roughly 73% of domestically generated electricity (compared to 45% in Q2 2018). Overall gross imports from countries outside the single market fell by 16% year-on-year in 2Q 2019.

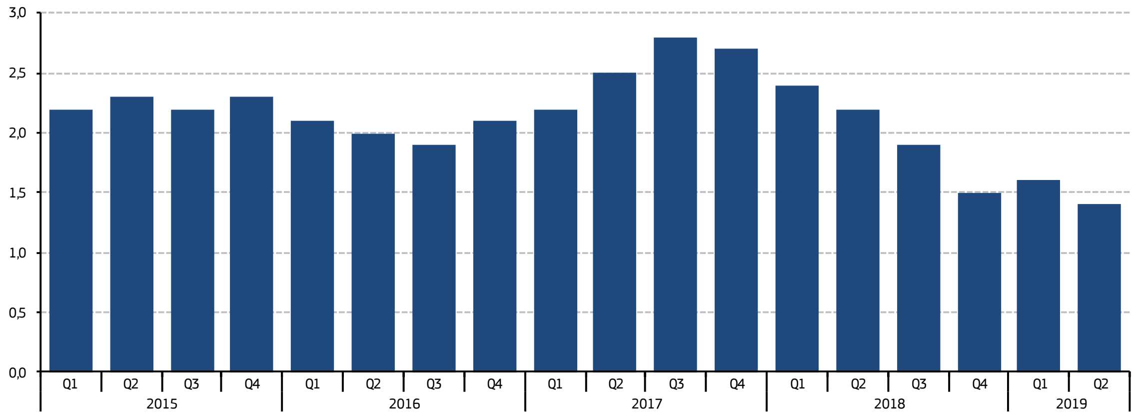
- In June 2019, Germany (31.0 c€/kWh) reported the highest median household price for electricity consumers, overtaking Belgium (30.0 c€/kWh). Industrial consumers with large annual consumption, including most energy intensive users, paid the highest prices in the UK (13.0 c€/kWh) followed by Slovakia and Ireland. The lowest prices in the category were reported by Luxembourg (3.7 c€/kWh) followed by Sweden and Finland.

1 Electricity market fundamentals

1.1 Demand side factors

- **Figure 1** shows that the pace of economic growth in the European Union continued to slow down in the second quarter of 2019 compared to previous quarters. According to an estimate published by Eurostat, seasonally adjusted GDP in the EU-28 expanded by 1.4% year-on-year between April and June 2019, which compares to 2.2% achieved in Q2 2018.
- According to the approximated data of the European Network of Transmission System Operators (ENTSO-E), EU-wide consumption of electricity rose by 0.7% year-on-year to 753 TWh in Q2 2019 as increases in some member states slightly outweighed falls in others. Of the major economies, power consumption went up in France (+3.9%), Spain (+2.8%) and Poland (+1%), while decreases were registered in Germany (-1.4%), the UK (-0.8%), and Italy (-0.2%). All three latter mentioned countries experienced negative or zero economic growth in the reference quarter. Overall stagnation of industrial activity in the EU was dragging the consumption levels lower, whereas households tended to increase their power offtake in Q2 2019.

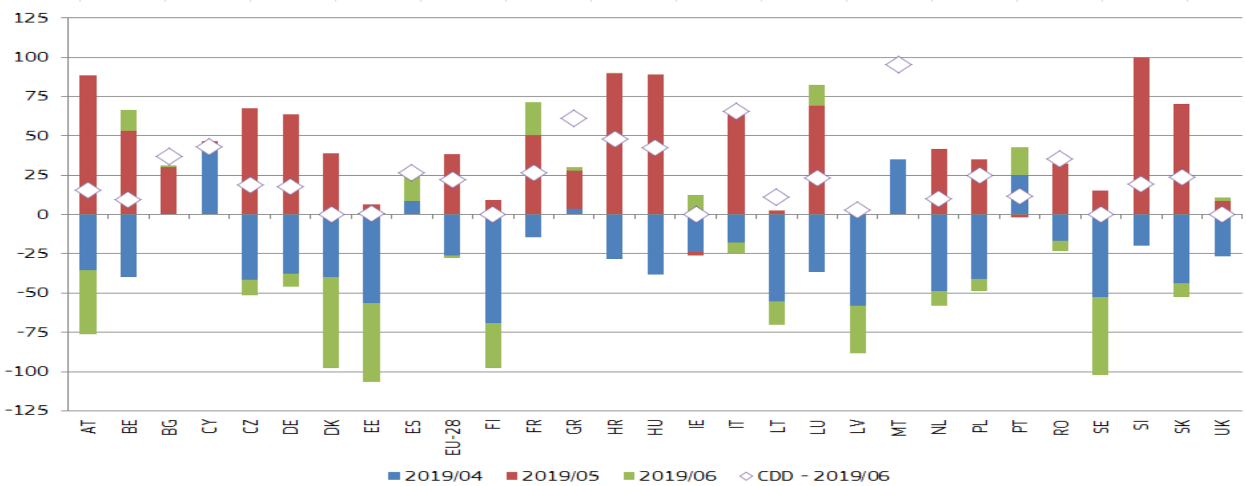
Figure 1 – EU 28 GDP annual change (%)



Source: Eurostat

- **Figure 2** illustrates the monthly deviation of actual Heating Degree Days (HDDs) from the long-term average in Q2 2019. On EU-28 average, the quarter had 10 HDDs above average (which translates to 0.1 °C colder than average per day) due to colder weather in May which was partly offset by a generally warmer April. In June, when heating degree days are less relevant, cooling needs are reflected in cooling degree days (CDDs). In some European countries (Malta, Italy, Greece, Spain, Hungary, Croatia, Cyprus, etc.) June was warmer than usual, which might have resulted in an increase in domestic electricity consumption for cooling needs, also impacting gas-fired electricity generation.

Figure 2 - Deviation of actual heating degree days and cooling degree days from the long-term average, in April-June 2019



Source: JRC.
The colder the weather, the higher the number of HDDs. The warmer the weather, the higher the number of CDDs.

1.2 Supply side factors

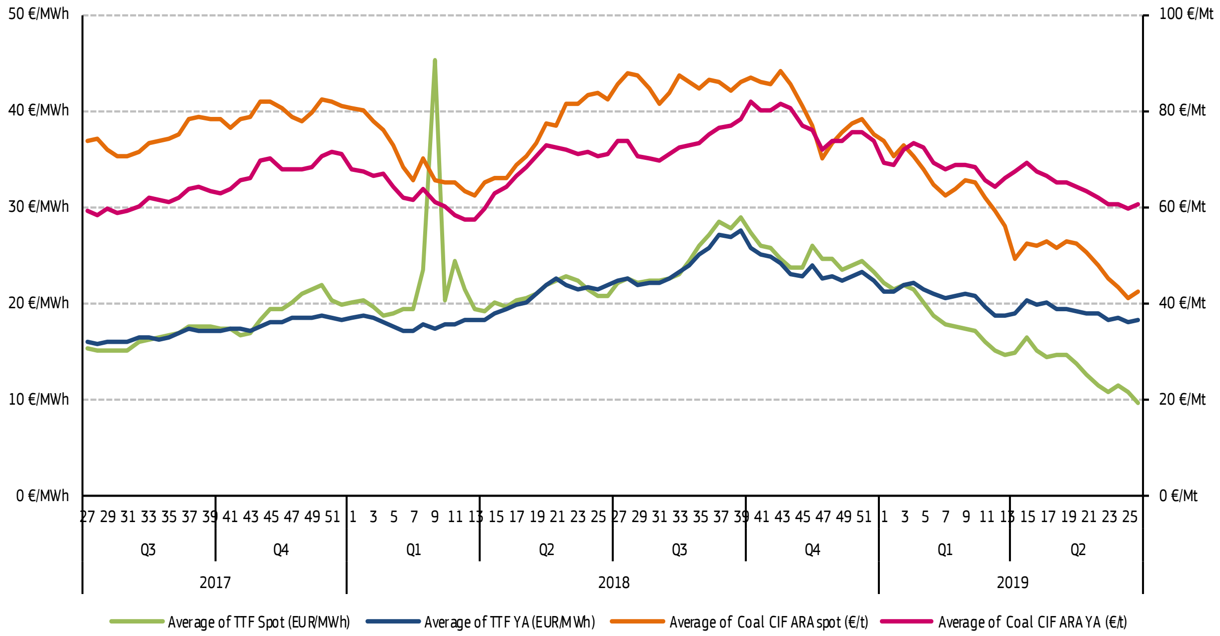
- **Figure 3** reports on the developments in European coal and gas prices which both continued in their slide during the reference period, after reaching a peak at the beginning of Q4 2018. Spot prices of both commodities registered steeper falls, increasing their distance from year-ahead prices and intensifying their contango position. This suggests market participants expect the supply-demand dynamic to change in the next year for both commodities.

- Spot gas prices showed some gains at the beginning of the reference quarter, amid curtailed pipeline flows from Norway and colder temperatures. But the upswing did not last long and after a calmer period spot contracts started to fall again in the middle of May on the back of weakening demand, high pipeline flows from Russia, plentiful LNG supply and high storage levels. Overall, the TTF spot contract weakened by 37% during the reference period, finishing the quarter at 9.30 €/MWh, which was 55% lower than at the same time last year and a 10-year low. Not even a 39% year-on-year increase in gas-fired power generation (roughly 7bn cubic meters of additional gas burn), registered in the reference quarter, could change the downward trend.

- Spot coal prices, represented by the CIF ARA contract, followed a similar path as gas, falling by almost 21% during Q2 2019 and finishing the quarter at 42.18 €/Mt, the lowest level since Q1 2016. High stocks at the Dutch terminals, low demand from generators and falling gas prices (a direct competitor fuel in the European electricity production) continued to depress the market. Contributing to the oversupply of coal in Europe was weak Asian demand, especially in China where growth in power consumption has slowed recently and increased output of other generation sources has disproportionately hit coal demand.

- Year-ahead gas prices, by contrast, decreased only by 4% during the second quarter of 2019, arriving at 17.93 €/MWh at the end of the period, clouding the prospect for coal-to-gas switching in the next year. Year-ahead coal prices declined by 9% during the reference period, responding to rising futures prices of emission allowances and falling gas futures contracts.

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



Source: S&P Global Platts

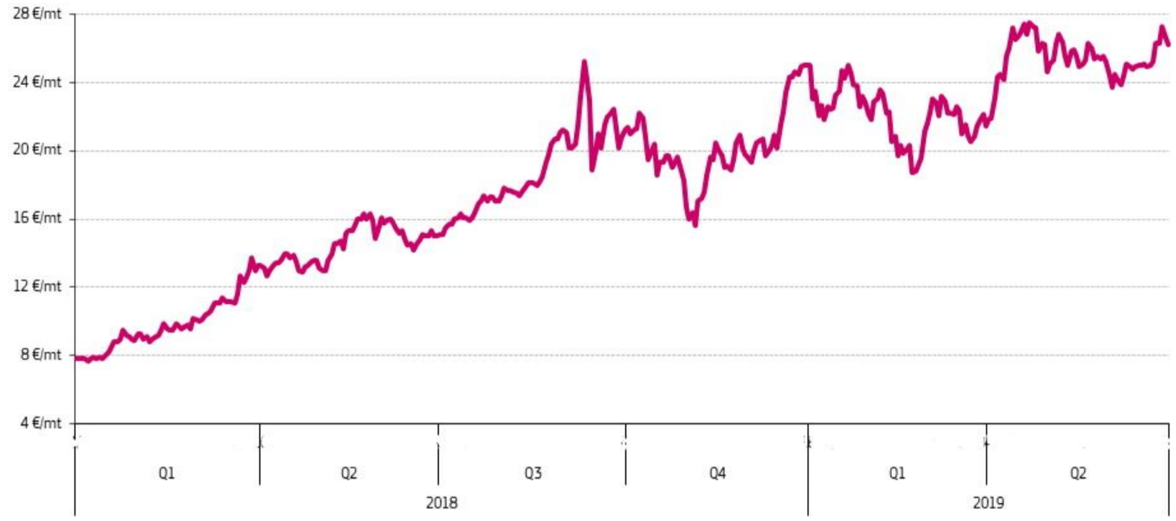
- The emission allowance market, shown in **Figure 4,** posted significant price gains in Q2 2019, moving from roughly 22 €/t at the beginning of the quarter to levels above 26 €/t at the end. Prices began to climb up right from the start of the quarter amidst firming spot gas prices (which benefit coal-fired generation and, hence, increase demand for CO2 permits). Another factor driving up the price was an increasing chance of a negotiated settlement between the EU and the UK, which implied more predictability about the UK's future participation in the EU ETS and, by extension, more certainty about the short term supply-demand equilibrium in the market. The upward trend culminated in the middle of April, after the European Council agreed to postpone the Brexit deadline until October 31 this year. The CO2 spot price surpassed 27 €/t in the aftermath, reaching the highest level since first auctions started in November 2008. Hedging demand among utilities also helped push prices higher, as coal-fired output continued to be competitive against gas-fired generation in some countries on the forward curve. Another factor supporting demand for allowances towards the end of April was the approaching April 30 deadline for companies to surrender their allowances to match their verified emissions in 2018, which spurred some last-minute compliance buying. May saw the spot prices climbing down from record highs on some profit-taking, softer demand and weaker gas prices. In June, allowance prices stabilized above the 24 €/t level and climbed above 26 €/t towards the end of the quarter, taking support from rising power prices.

- Overall, the CO2 spot price rose by 20% throughout the reference period, putting further pressure on carbon-intensive generation capacities, especially in the coal-fired sector. At 25.44 €/t, the average price of one allowance in Q2 2019 was more than 75% higher than the average price in the same quarter a year ago (14.50 €/t). Increased trading activity on the secondary market suggests that the carbon market has attracted attention of a wider pool of participants than in the previous years. Anecdotal evidence also points to an increased interest among hedge funds.

- The British government has said it will halt its participation in the EU ETS in the event of a no-deal Brexit. This could result in a supply overhang of carbon allowances accumulated over the last years by some participants who could see no need to retain them anymore. In Q2 2019, as in the previous quarter, both the free allocation and auctioning of emissions allowances by the UK government was suspended. The resumption of auctioning and free allocation is expected after a deal will have been reached between the EU and the UK. Meanwhile, the reduced supply of allowances stemming from the significant UK volumes blocked from entering the market puts upward pressure on prices.

- Supply from auctions in Q2 2019 was also reduced by the Market Stability Reserve (MSR), activated this year for the first time to deal with the structural surplus of allowances in the market. The total auction volumes in the first 8 months of 2019 year have been reduced by nearly 265 million allowances, corresponding to 16% of the total number of allowances in circulation calculated in May 2018. This first MSR feed was calculated on the basis of the rate of 24% of the surplus applying over a 12-month period, corresponding to 16% for the actual 8-month period from January to August 2019. From September 2019 to August 2020 the number of allowances placed in the reserve (and thus not entering the market through auctions) will amount to approximately 397 million. This corresponds to 24% of the total number of allowances in circulation calculated in May 2019. The withdrawal of allowances and their placement in the reserve will continue as long as their total number in circulation exceeds a pre-defined threshold (833 million allowances).

Figure 4 – Evolution of emission allowance spot prices from Q1 2018



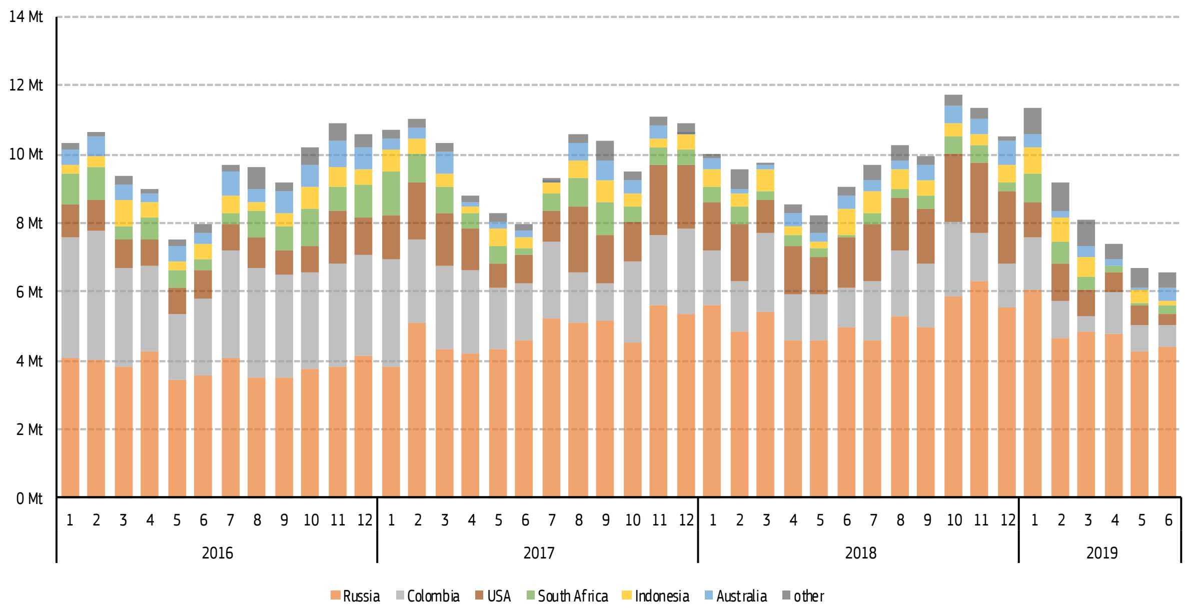
Source: S&P Global Platts

- **Figure 5** reports on extra-EU thermal coal import sources and monthly amounts of imports of the commodity into the EU. Provisional Eurostat data show that in the second quarter of 2019 thermal coal imports from outside the EU reached 20.2 Mt, the lowest quarterly amount on record. The volume of imported coal in the reference quarter came 22% lower compared to the same quarter of 2018 (25.8 Mt) and more than 19% lower compared to Q2 2017 (25.0 Mt), which reflects a gradually decreasing role of the fuel in the EU generation mix (see **Figure 9**) and adverse conditions for coal-fired generation in the quarter (see **Figure 12**). In Q2 2019 the estimated EU import bill for thermal coal amounted to €1.7 billion, 22% lower compared to Q2 2018, mirroring the year-on-year decline in imported volumes in the reference quarter.

- The largest share of extra-EU thermal coal imports in the reference quarter came from Russia, accounting for nearly two thirds (65%) of the total. Russia has noticeably strengthened its position in the European thermal coal market lately. Russian suppliers steadily increased their share in the last couple of years, building it up from 40% of all imports in 2016 to 48% a year later and 52% in 2018, mainly at the expense of their Colombian and US competitors. This development can be explained partly by favourable shipment costs and rouble/euro exchange rate, partly by increasing production in Russia (which reached a record of 433 Mt in 2018, surpassing the Soviet maximum from 1988) and also partly by deliberate efforts of Russian exporters to expand their presence in the European market, especially in Germany. The second most important thermal coal import source was Colombia, although its share fell from 15% in Q2 2018 to 13% in the reference period. The United States was the third most important thermal coal trading partner of the EU in the reference period, accounting for 7% of all imports (down from 15% a year erlier). South Africa and Australia both accounted for 3% of EU's thermal coal imports in the reference period, while the Indonesian share amounted to 2.4%.

- The decline in thermal coal shipments in the reference period could be observed in all major EU import markets. Deliveries to German and Dutch terminals (calculated together as many German plants are supplied via Dutch ports) fell by 5% year-on-year to 9.1 Mt, even as utilities restocked coal plants in southern Germany to avoid transportation bottlenecks experienced in the second half of 2018 due to low Rhine levels, and as contango on the forward curve (see **Figure 3**) created a strong incentive to store coal to capitalize on the difference between weak spot prices and higher-priced forward contracts. Polish thermal coal imports decreased by a third year-on-year to 2.4 Mt in Q2 2019, while imports to Italy (1.9 Mt), Spain (1.9 Mt) and France (1.3 Mt) registered similar slides. The most dramatic drop in thermal coal deliveries (by 63 % year-on-year to 0.4 Mt) was recorded by British terminals where in April almost no new deliveries took place.

Figure 5 – Extra-EU thermal coal import sources and monthly imported quantities in the EU-28



Source: Eurostat.

2 European wholesale markets

2.1 European wholesale electricity markets and their international comparison

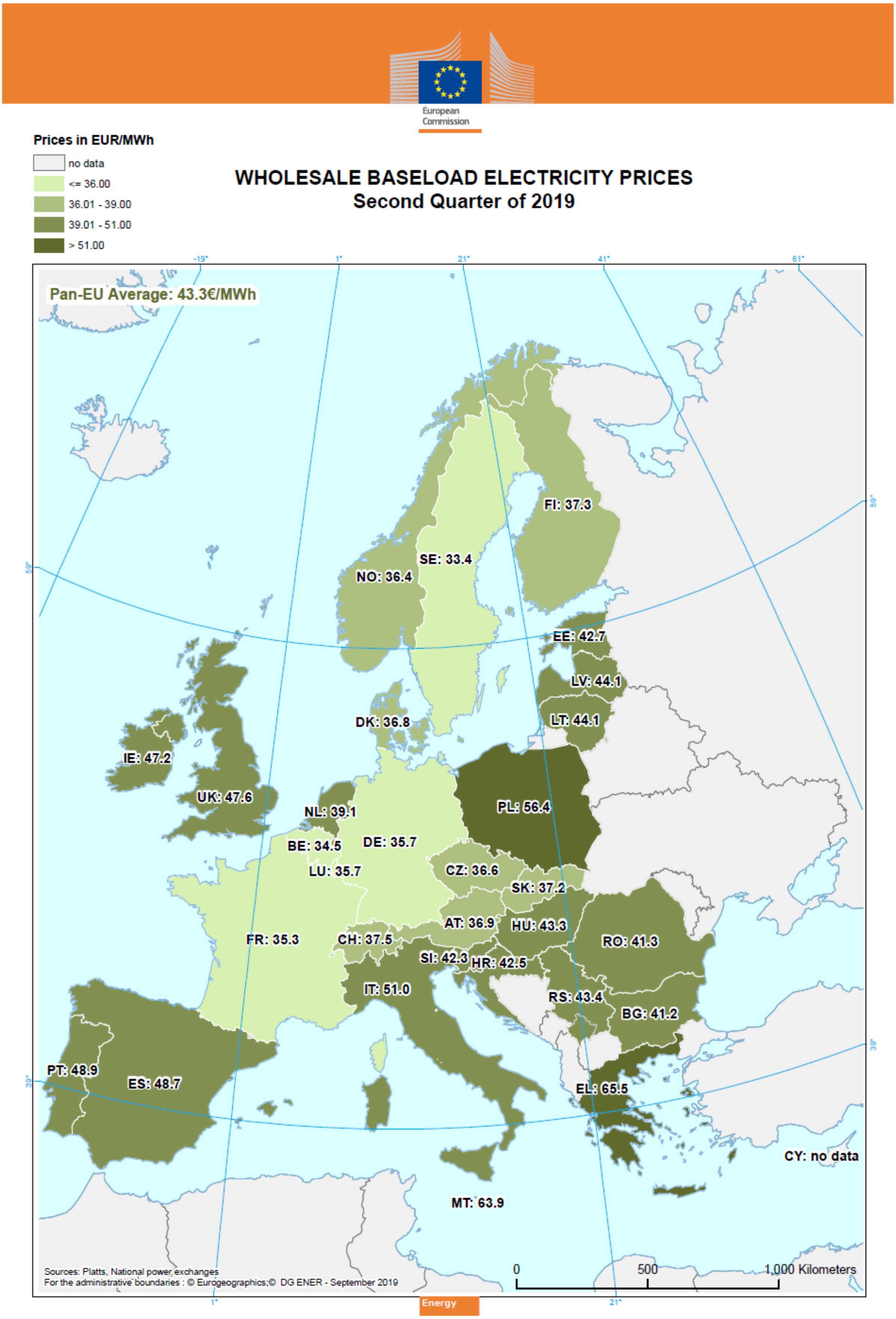
- The next map shows, that significant differences in average wholesale electricity prices across Europe persisted and even grew in the second quarter of 2019, with Greek baseload contract reaching double its Swedish peer. The difference between the most expensive and cheapest market stretched to more than 32 €/MWh, one of the highest on record. The growing divergence could be partly explained by the effect of rapidly expanding renewable capacity in some countries or bidding zones and also by the effect of a significantly strengthened CO2 price which impacts different markets and zones unevenly, depending on the local generation mix. This trend, coupled with several critical grid situations which occurred in the reference quarter, points to the need for increased investment in strengthening network resilience and expanding cross-border capacities.

- The highest average wholesale electricity prices in Q2 2019 could be observed in Greece (65.5 €/MWh), Malta (63.9 €/MWh), Poland (56.4 €/MWh), and Italy (51.0 €/MWh), all of which are either traditionally significant importers of electricity and/or have limited cross-border transmission capacities or (in the case of Poland) face increased production costs due to high CO2 prices on its carbon-intensive generation mix. The lowest quarterly wholesale prices were recorded in Sweden (33.4 €/MWh) which benefited from ample hydro reservoir levels and a record output from its fast-growing wind fleet.

- The pan-EU average of wholesale baseload prices reached 43.3 €/MWh in the reference quarter, down 1% in a year-on-year comparison. Compared to Q1 2019, the wholesale benchmark fell by 11.5% on the back of lower fuel prices, growing renewable penetration and tepid demand growth.

- In terms of price developments in individual markets, the biggest year-on-year price swings in the upward direction took place in Bulgaria (+22%), Greece (+17%) and Poland (+14%), whereas the largest falls could be observed in Belgium (-22%), the UK (-21%) and the Netherlands (-15%).

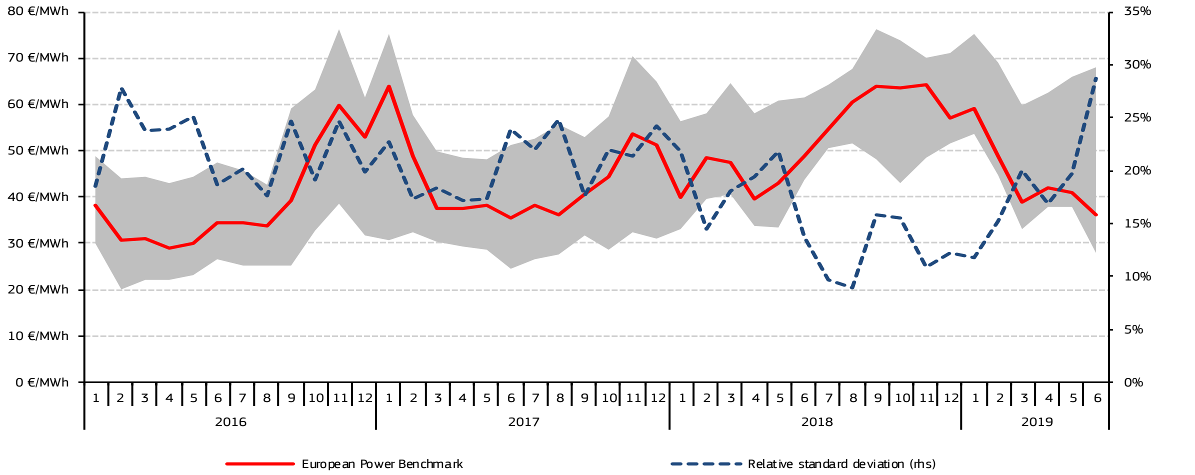
Figure 6 – Comparison of average wholesale baseload electricity prices, second quarter of 2019



Source: European wholesale power exchanges, government agencies and intermediaries

- **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 band and the relative standard deviation metric show that after reaching the highest degree of convergence on record in Q3 2018, wholesale prices across different regional markets in Europe began to diverge again at the start of 2019. This trend continued in Q2 2019 despite a short break in March and April. In June the divergence reached high levels last seen in 2015, as prices in Northern and Western Europe fell (in some cases significantly) on the back of surging renewable output, while southern EU markets, affected by underperforming hydro output, registered smaller decreases, with Greek prices rising throughout the reference period.

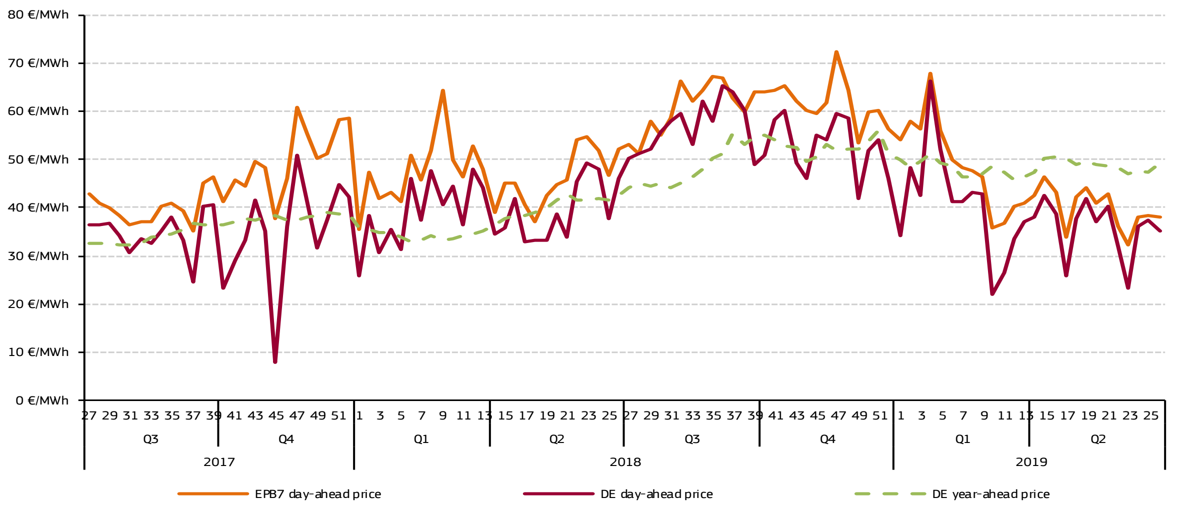
Figure 7 – The evolution of the lowest and the highest regional wholesale electricity prices in the EU and the relative standard deviation of the regional prices



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, as well as German day-ahead baseload and year-ahead contracts in the reference period. Germany serves as a point of reference, having one of the most liquid markets in Europe with available forward curve price quotations. Both day-ahead EPB and German day-ahead baseload contracts show the impact of decreasing fuel prices (coal and gas) for marginal power plants, increasing renewable penetration and limited demand growth in the reference quarter. German prices, however, show larger volatility owing to a big influence of fluctuating wind and solar generation in the market and also due to the fact that the EPB is a composite index representing a wide pool of individual markets. Year-ahead German electricity prices registered a 6% increase in Q2 2019, moving in the same range between 46 and 51 €/MWh as in the previous quarter and deepening the gap between the forward curve and spot prices, in line with the developments in the primary fuels market (see **Figure 3**).

Figure 8 – Weekly evolution of day-ahead and year-ahead German electricity prices



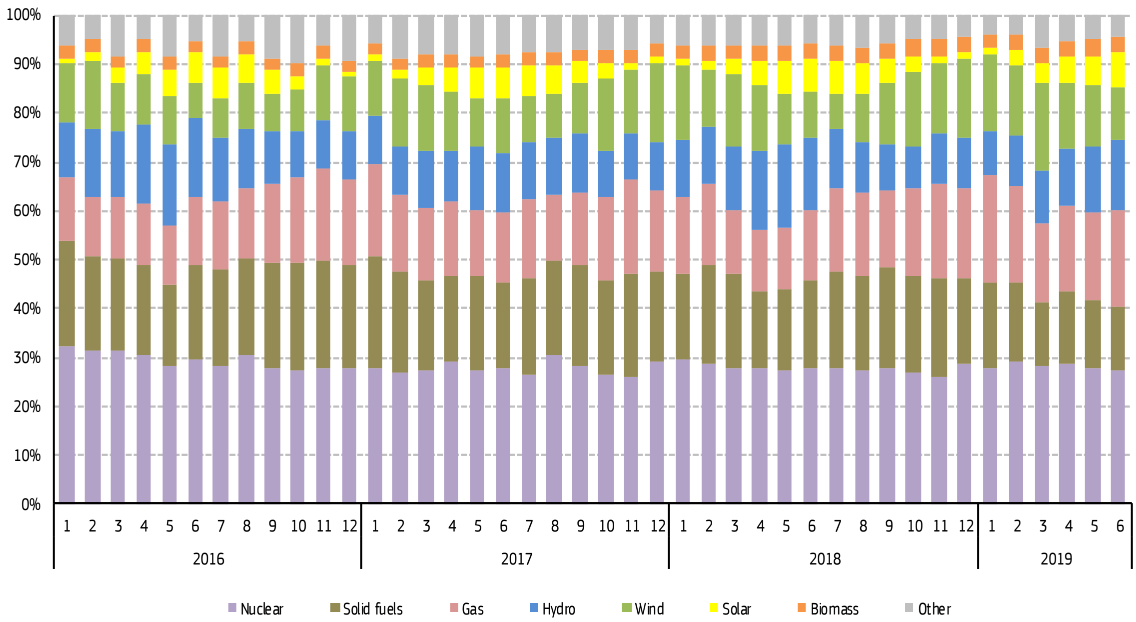
Source: S&P Global Platts and DG ENER EPB7 - European Power Benchmark (in €/MWh) is the replacement of the S&P Global Platts PEP since January 2017.

- **Figure 9** shows the evolution of the electricity generation mix in the EU-28. The dominant theme influencing the structure of the mix in the reference quarter was a growing role of gas which managed to increase its share at the expense of coal and also as a replacement for weaker hydro generation. Compared to the same quarter of the previous year, in Q2 2019 the share of fossil fuels increased from 30% to 32%, while the share of renewables (hydro, biomass, wind and solar) declined from 36.6% to 35.1% owing to a sharp drop in hydro generation which was relatively high in Q2 2018. The share of nuclear generation went slightly up - from 27.6% to 28.0% year-on year, as higher production in Spain, Belgium and France more than compensated for a lower output of the British nuclear fleet.

- Restricted demand growth throughout the quarter limited the potential for fossil fuel generation. Within the fossil fuels complex, the effect of high CO2 prices and coal-to-gas switching was visible. Less CO2-intensive gas generation dominated in nearly all countries with switching potential and reached 18.4% share in the overall mix in Q2 2019 (compared to 13.2% in Q2 2018 and 12.9% in Q2 2016). In absolute terms, gas-fired plants increased their output by 34 TWh year-on-year in the reference quarter which was the largest gain of all generation sources. Hard coal and lignite generation, on the other hand, saw its combined share reduced to 13.9% in the reference quarter (from 16.6% in Q2 2018 and 18.3% in Q2 2016). In June 2019, when ample renewable availability and very low gas prices exerted particularly heavy pressure on coal's position in the merit order, the share of solid fuels in the mix dropped to the lowest level on record (13.0%).

- Between hard coal and lignite, the latter tends to display more resilience under the current circumstances, as lignite generation has lower marginal costs per unit of energy produced. However, anecdotal evidence suggests that a combination of extremely low gas prices, higher renewable availability (which pushed down power prices) and heightened carbon costs started to seriously undermine the economics of some lignite units as well. As in the previous quarter, both fuels faced declining shares in the mix in Q2 2019, but this time lignite bore the brunt of the pressure, especially in June when hydro production partly recovered, favourable weather underpinned good solar output and gas prices reached multi-year lows. Apart from these factors, lignite-based generation in Germany was curbed by increased maintenance and mining restrictions. In the case of hard coal, its share in Q2 2019 decreased to 6.0% from 7.2% in Q2 2018; while the share of lignite fell to 7.9% from 9.4% a year ago. In terms of production volumes, lignite suffered a year-on-year fall of 9 TWh (June accounted for more than 2/3 of that), whereas hard coal recorded a decline of 8 TWh in the reference quarter. The distinction between hard coal- and lignite-based generation is not visible in Figure 9.

Figure 9 – Monthly electricity generation mix in EU-28

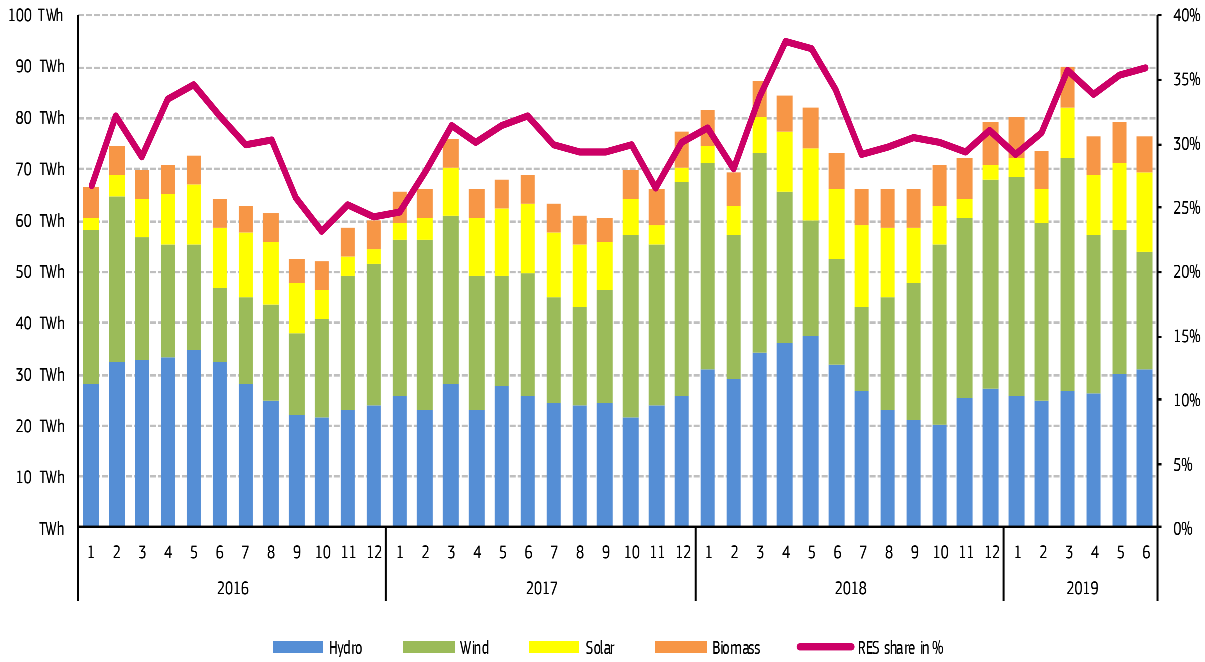


Source: ENTSO-E

- **Figure 10** depicts the evolution of the monthly renewable generation in the EU, alongside the share of renewables in the electricity generation mix. In Q2 2019 the trend of a gradually and continuously rising role of renewable generation was slowed down by weak hydro output which declined by 19 TWh (18%) compared to Q2 2018. The main factors were severe droughts in Spain and Portugal, where production fell by more than half year-on-year, and lower reservoir and precipitation levels in France and Italy, where output dropped by more than 25%. The share of hydro generation thus reached 13.2% in Q2 2019, compared to 16.1% in the same quarter last year.

- In contrast, wind-powered electricity generation recorded a strong second quarter of 2019 with a 9 TWh year-on-year jump in generation, reaching a 12.4% share in the overall mix and becoming, once again, the biggest contributer to renewable generation growth. The largest increases in wind output came from Germany, Spain, France and the UK. The share of solar generation reached 6.1%, the same as in previous Q2. The share of biomass stood at 3.4% in Q2 2019, a slight improvement on 3.3% in Q2 2018. Total combined output of solar, wind and biomass generation in the reference quarter increased by 7.5% year-on-year to 145 TWh (it reached 108 TWh in Q2 2015).
- The combined share of hydro, biomass, wind and solar in the EU generation reached 35.1% in Q2 2019 (compared to 36.6% in Q2 2018 and 33.5% in Q2 2016). This compares with 21.0% renewable energy share in the power generation of the United States and 23.3% renewable share in the Chinese power mix during the same quarter.[1]
- New wind installed capacity reached 4.3 GW in EU member states in the first half of 2019, only slightly higher than in the same period last year. Additional onshore wind installations totalled 2.4 GW (down from 3.1 GW in 1H 2018), while offshore additions rose to 1.9 GW (from 1.1 GW in 1H 2018). Countries leading the deployment of new onshore capacities the first half of 2019 were France (523 MW), Sweden (459 MW) and Germany (287 MW), while the best peformers in the offshore sector were the UK (931 MW), Denmark (374 MW) and Belgium (370 MW) which beat Germany (252 GW).[2]

Figure 10 – Monthly renewable electricity generation in the EU and the share of renewables in all electricity production



Source: ENTSO-E

1 Calculations based on the data from Energy Information Administration in the US and China Electricity Council. The Chinese figure does not contain burning of biomass.

[2] Acccording to data from WindEurope.

- **Figures 11 and 12** report on the profitability of gas-fired and coal-fired electricity generation by looking at the spread indicators on selected wholesale markets. In Q2 2019 gas increased its lead over its competitor compared to the previous quarter thanks to its decreasing prices and ever more expensive emission allowances.

- In the UK the effect of decreasing spot gas prices was almost neutralized by falling baseload and peakload contracts and rising CO2 prices, which nudged the clean-spark spreads only slightly higher than in the previous quarter. Clean dark spreads in the UK, on the other hand, moved deeper into the negative territory to record low levels due to rising carbon prices. As a result of its extremely low profitability, coal-fired generation was pushed to the margins of the UK market and its output reduced to nearly zero in May and June.

- German spark spreads received a boost from increasing average electricity prices in the first half Q2 2019. In the rest of the quarter, when power prices retreated somewhat, falling continental gas benchmarks pushed the spark spreads to record highs. This resulted in a gradually increasing profitability of gas-fired generation and positive margins across the entire efficiency spectrum. Meanwhile, as CO2 prices kept climbing up, dark spreads for average German coal plants sank deeper into the negative territory and were hovering close to break-even levels in the case of high-efficiency units. Thus, in June German gas plants came ahead of even the most efficient coal competitors on the merit order curve.

- However, a number of the higher efficiency coal plants proved less sensitive to respond and some coal units maintained production in view of the necessity to provide heat (the CHP plants). As a result, actual hard-coal generation in Q2 2019 in Germany was higher than what the dark spreads would suggest, decreasing by 23% year-on-year (or 2.5 TWh). Gas-fired generation over the same period increased by 62% (or 4 TWh) compared to Q2 2018, replacing also some lignite output which registered a 6.7 TWh year-on-year decline.

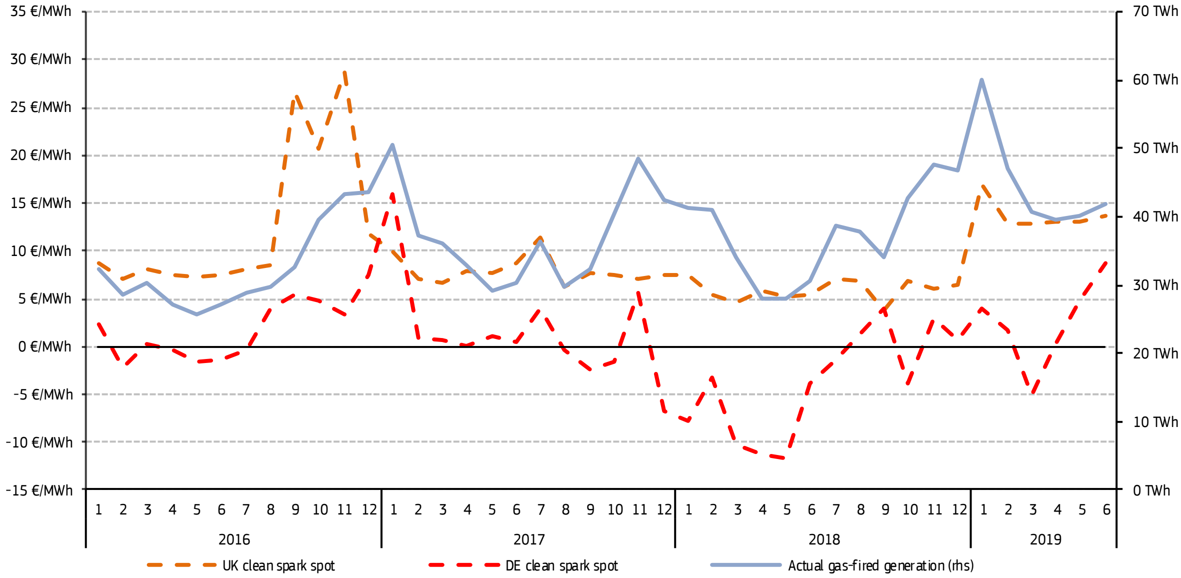
- In other countries with coal-to-gas switching potential, the effects of the divergence between spark and dark spreads were also pronounced in the reference period. In France, coal-fired output fell by 95% year-on-year to almost zero, while gas-fired generation expanded by 160% year-on-year (or 3.5 TWh), helping also to compensate for a very weak hydro performance. A similar scenario played out in drought-stricken Spain where gas stepped in to mitigate very low hydro generation and recorded 7 TWh of extra output compared to Q2 2018, at the expense of coal which lost 4 TWh year-on-year. The highest absolute increase in gas-fired generation took place in Italy (up 12 TWh year-on-year), where margins of gas-fired plants have traditionally been higher compared to Germany.

- In the EU as a whole, gas-fired generation reached 122 TWh in Q2 2019, the highest figure for a Q2 in at least 5 years and a 39% increase compared to the same quarter last year. Hard-coal generation, on the other hand, fell by 16% year-on-year to 40 TWh in the reference quarter. The driving forces behind this dynamic remained the same as in the previous quarter: extremely low gas prices, which reached a 10-year low in June 2019, and continuously rising CO2 prices, which hovered above 24 €/t during most of Q2 2019 and which put the much more CO2-intensive coal-fired generation at a big disadvantage to gas. The trend of increasing spark spreads was visible also along the forward curve, with German year-ahead clean spark spreads reaching highest levels in nine years. There could be some potential for further switching in Germany, which has sizable underutilized gas-fired capacity with the average load factor moving between 20% and 40%, depending on the plant type.[3] However, lower power demand in the summer, growing renewable output and the necessity to maintain CHP units running will hinder additional switching.

- Given the exhausted potential for additional coal-to-gas switching in some countries, further increases in carbon prices might start endangering the viability of gas generation assets there.

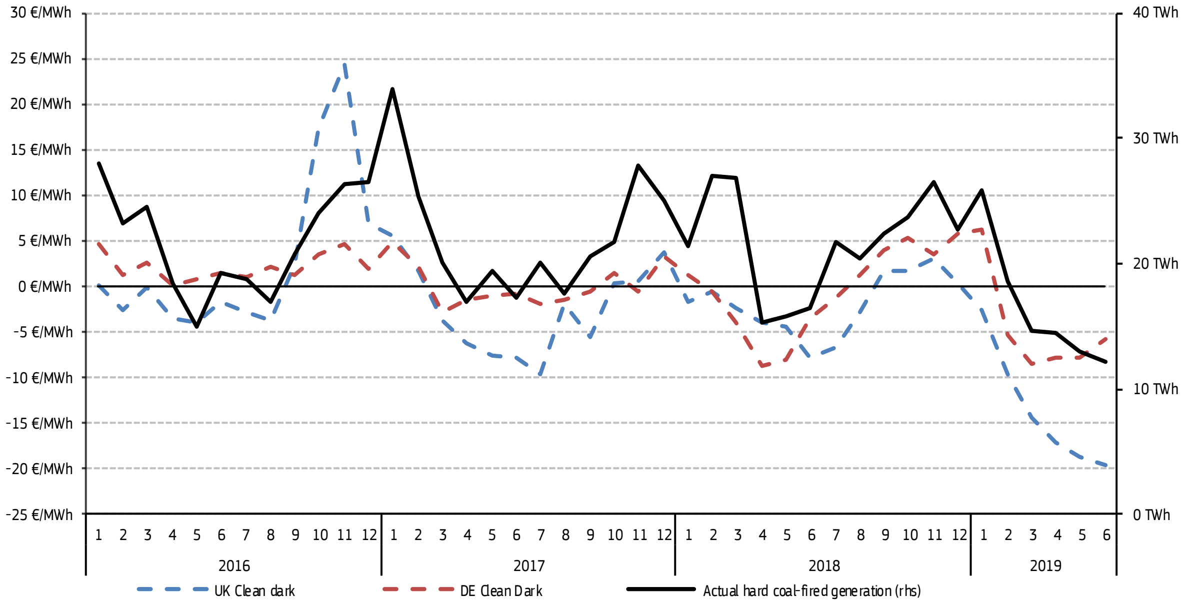
[3] Calculations by the German gas industry organisation Zukunft Erdgas.

Figure 11 – Evolution of clean spark spreads in the UK and Germany, and electricity generation from natural gas in the EU



Source: S&P Global Platts and ENTSO-E

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

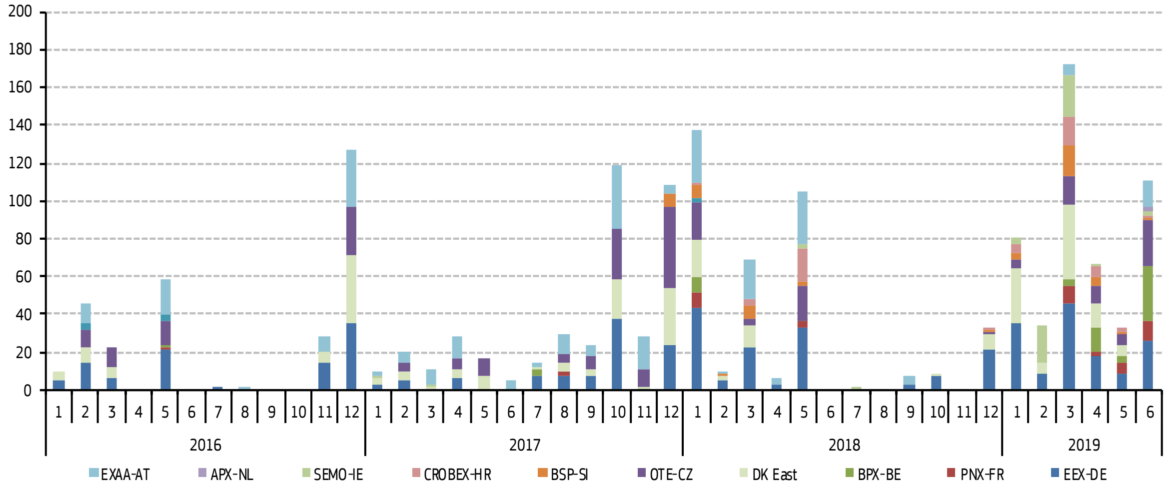


Source: S&P Global Platts and ENTSO-E

- **Figure 13** shows the monthly frequency of the occurrence of negative hourly wholesale electricity prices in selected EU markets. Negative hourly prices usually appear when demand for electricity is lower than expected and when variable renewable generation is abundant, combined with ongoing relatively non-flexible large baseload power generation (e.g.: nuclear). In such cases, conventional power plants begin to offer their output for a negative price in an effort to avoid switching the unit off and having to go through the costly and high-maintenance operation of restarting the facility when they are required again.
- The number of hours with negative wholesale prices in Q2 2019 was relatively high compared to the previous Q2 last year (+51% year-on-year), but lower than the last quarter (-27% compared to Q1 2019). Most of the falls into the negative territory occurred in June (111), specifically during June 8 when trading was heavily influenced not only by low weekend demand and good renewable availability, but also by a very rare event when markets in Western Europe decoupled owing to a technical failure during the day-ahead auction at the Epex Spot exchange (see **Figure 21**). As the Belgian market was most affected by the incident, it recorded the largest

number of negative hourly prices in June (28), surpassing even traditionally sub-zero-prone Germany (26). Another particularly high concentration of negative hourly prices occurred on Easter Monday in April.

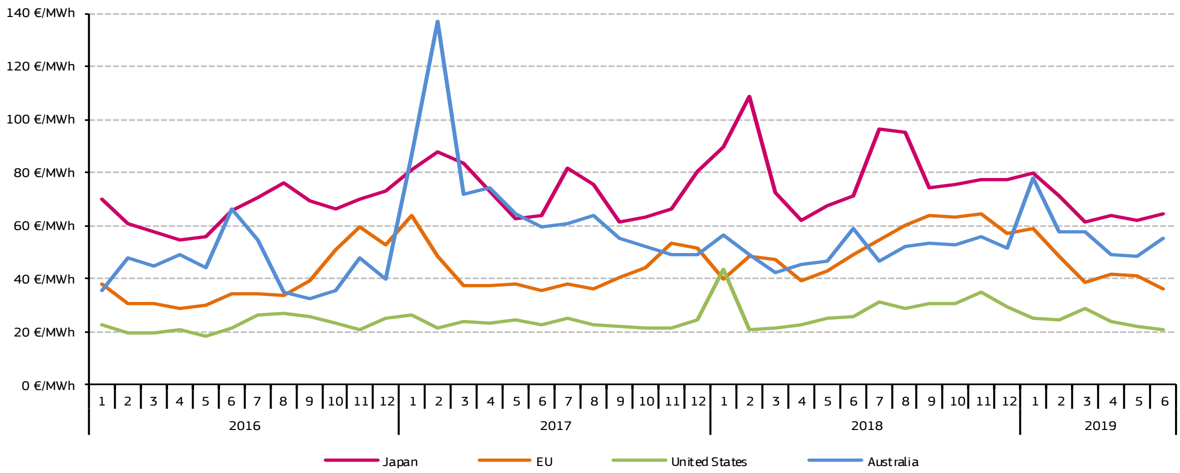
Figure 13 – Number of negative hourly wholesale prices on selected trading platforms



Source: Platts, European wholesale electricity markets

- **Figure 14** shows that in the second quarter of 2019 the gap between wholesale electricity prices in Europe and the US slightly widened compared to the end of the previous quarter as the US benchmark posted a steeper fall than its EU peer on the back of extremely low prices of the domestically produced US gas (which was on average 30-40% cheaper than gas supplied in Europe). Quarterly wholesale prices in the EU were 17.4 €/MWh higher than the US prices in the reference quarter on average, which compares with a 19.2 €/MWh price differential a year ago.
- Wholesale electricity prices in Australia fell under 50 €/MWh during the first two months of Q2 2019 and rose above 55 €/MWh in June, as the high winter season in the Southern Hemisphere propped up demand. Monthly average wholesale prices in Japan, meanwhile, remained broadly unchanged during the reference period, moving between 62 and 64 €/MWh.

Figure 14 – Comparison of the monthly average wholesale electricity prices in Europe, US, Japan and Australia



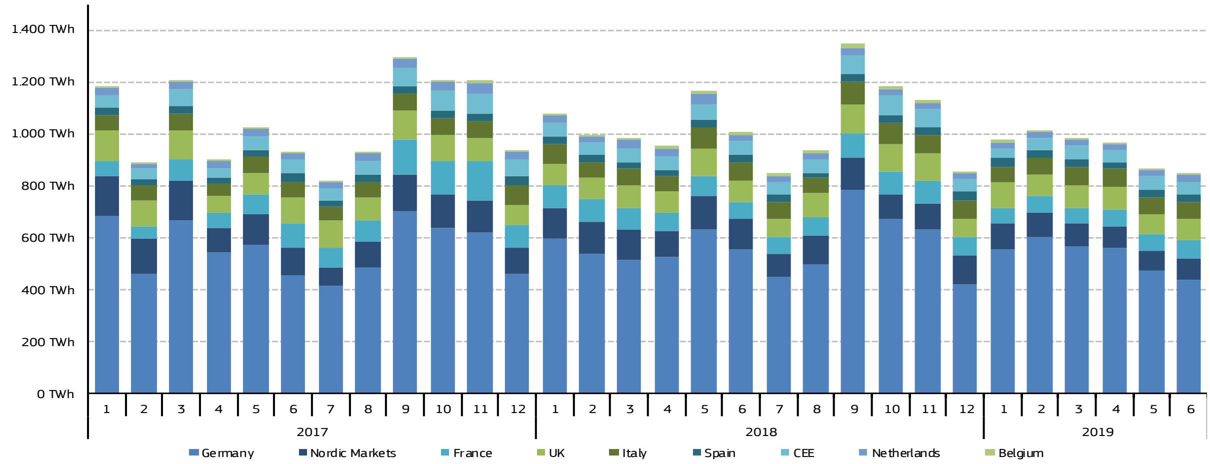
Source: European Power Benchmark, JPEX (Japan), AEMO (Australia) and the average of PJM West and ERCOT regional wholesale markets in the United States

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 2019 the highest trade volumes could be observed in the German market, followed by the UK, which overtook the combined volumes of Nordic markets by a slight margin. Italy and France came fourth and fifth respectively.

- Traded volume of electricity shows a high degree of seasonality, with activity usually slowing towards the summer months and picking up again after the holiday season. However, in the second quarter of 2019, the total quarterly traded volume of electricity showed a noticeable 14% decrease to 2,683 TWh compared to the same quarter last year in which the total volume reached 3,123 TWh.

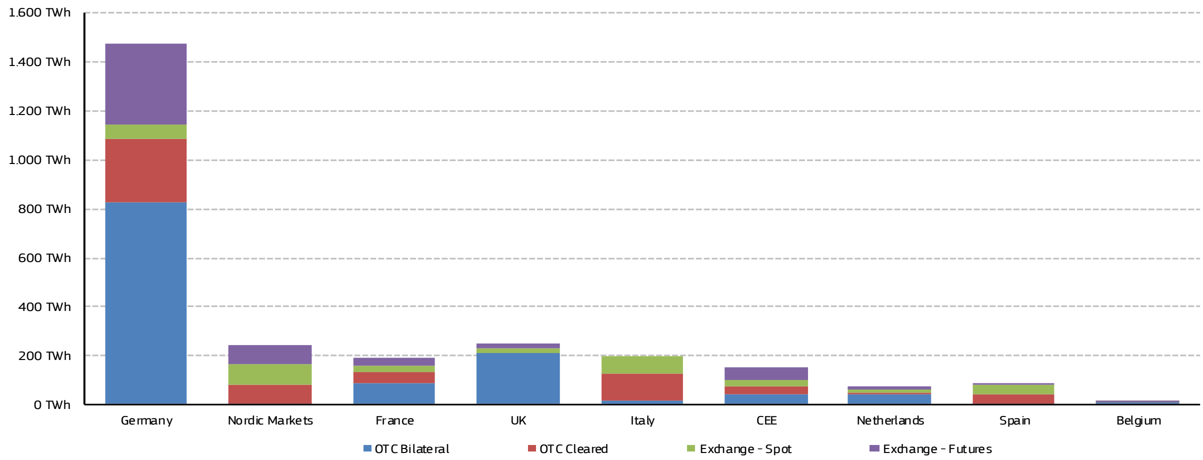
Figure 15 – Monthly traded volume of electricity on the most liquid European markets



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 2019 all markets, except for Spain, reported year-on-year declines in activity, with Belgium (-49%) and the Nordics (-29%) showing the largest relative losses. The decrease in trading volumes compared to Q2 2018 in the German market (-14%) was in line with the overall average during the reference quarter. More modest year-on-year declines were reported from France (-11%), Italy (-10%) and the United Kingdom (-6%). Spanish power market, on the other hand, saw a 5% increase in trading activity in Q2 2019 compared to the same quarter last year.
- In different segments of power market trading the volume dynamic was mixed. The fall in total trading activity in Q2 2019 in the reference quarter was driven mainly by a lower interest in over-the-counter (OTC) trading, which registered a 20% drop year-on-year, while the volume of exchange-executed contracts increased by 1% year-on-year. Consequently, the share of exchange-executed trade increased from 28% to 33% between the second quarter of 2018 and 2019. The slight year-on-year rise of exchange-traded activity was driven mainly by the German futures market, where traded volumes jumped by 56 TWh, and to a smaller extent by the Spanish market (+3 TWh), whereas the other markets reported a combined decrease of 53 TWh traded on exchanges in Q2 2019. The shift from OTC to exchange-executed trading comes as more and more small producers enter the market and for reasons of convenience meet at a central marketplace rather than trade bilaterally. The use of a clearing centre also reduces financial and counterparty risks.

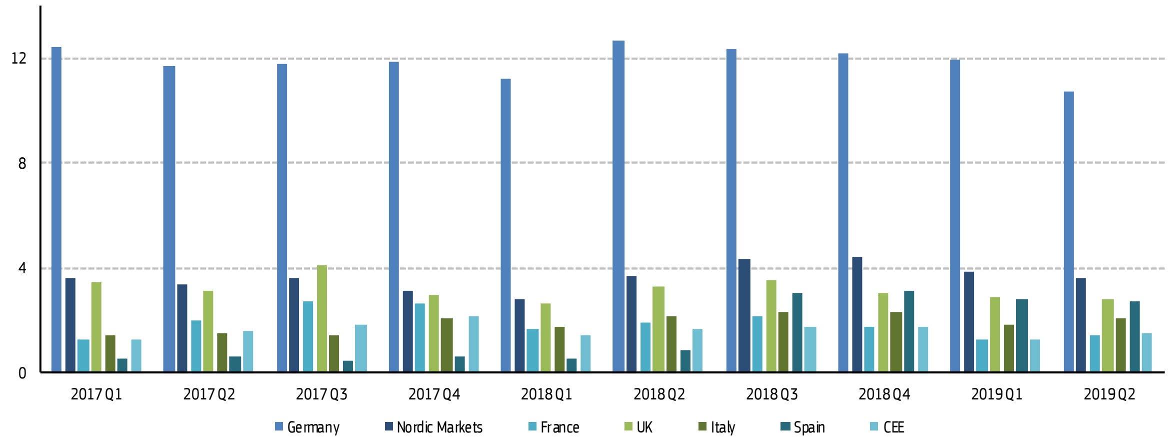
Figure 16 – Comparison of electricity traded volumes in selected day-ahead, forward and OTC markets, second quarter of 2019



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

- Market liquidity can be measured by the churn rate which is calculated as 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. In other words, the churn rate measures how many times a unit of electricity is traded before it is finally consumed.
- **Figure 17** shows the evolution of the quarterly regional churn rates from early 2017 to the end of the reference period. Germany remained by far the most liquid market in Europe, with churn rates 3 to 7 times higher than in other regional markets in Q2 2019. Compared to the same period of the previous year, market liquidity measurably decreased in Germany (as the churn rate went down from 12.7 in Q2 2018 to 10.7 in Q2 2019) and the UK (from 3.7 to 2.8 in Q2 2019), whereas Spain registered a significant increase in liquidity (from 0.9 to 2.7). Compared to the previous quarter, churn rates increased in France, Italy and the CEE region. The other markets recorded a fall in liquidity.

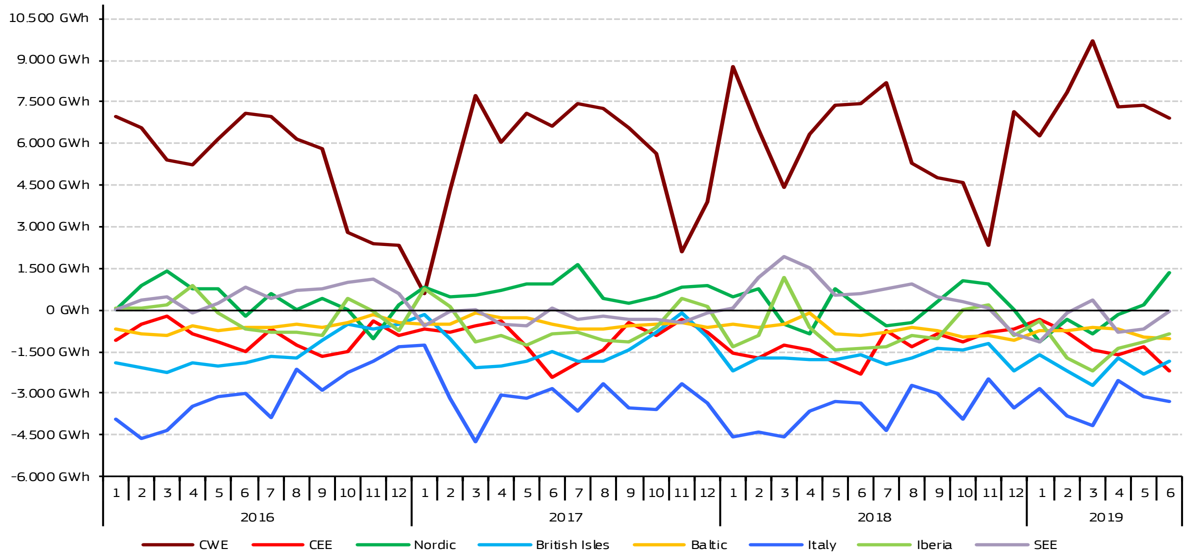
Figure 17 – Quarterly churn rates on selected European wholesale electricity markets



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

- **Figure 18** reports on the regional cross-border flows of electricity in Q2 2019. The CWE region continued to dominate as the export powerhouse of the continent, having plentiful and diverse generation capacities, competitive prices and a central position suitable to supply all the other regions. Monthly net export flows were relatively stable adding up to 21.7 TWh for the whole reference quarter (+3% compared to Q2 2018). Strong renewable generation and a good performance of the French and Belgian nuclear fleet contributed to this result.
- Italy remained by far the largest importer of electricity in Q2 2019, receiving 8.9 TWh of net inflows, mainly from Switzerland and France and, to a lesser extent, Slovenia. A minor fraction of this volume was shipped to Malta and additional 0.6 TWh were exported to Greece. Compared to Q2 2018 the net import volume decreased by 13% on the back of falling demand and record domestic gas-fired generation. The second largest importer region, the British Isles, increased its net purchases in Q2 2019 to 5.9 TWh (+13% year-on-year) amid low output of its nuclear fleet suffering from outages. The CEE region saw net imports decrease by 9% year-on-year to 5.1 TWh thanks to good utilisation rates of local nuclear units, strong hydro generation in Slovakia and despite growing demand.
- South Eastern Europe shifted from being a net exporter in the previous Q2 to importing 1.6 TWh in Q2 2019, as uneven hydro generation and high carbon emissions costs for local lignite units drove power prices too high to be competitive in neighbouring markets. The Nordic region emerged as a net exporter only in the second half of the reference quarter thanks to surging Swedish renewable generation. The net position of the Iberian Peninsula (-3.4 TWh) remained unchanged in the reference quarter compared to Q2 2018.

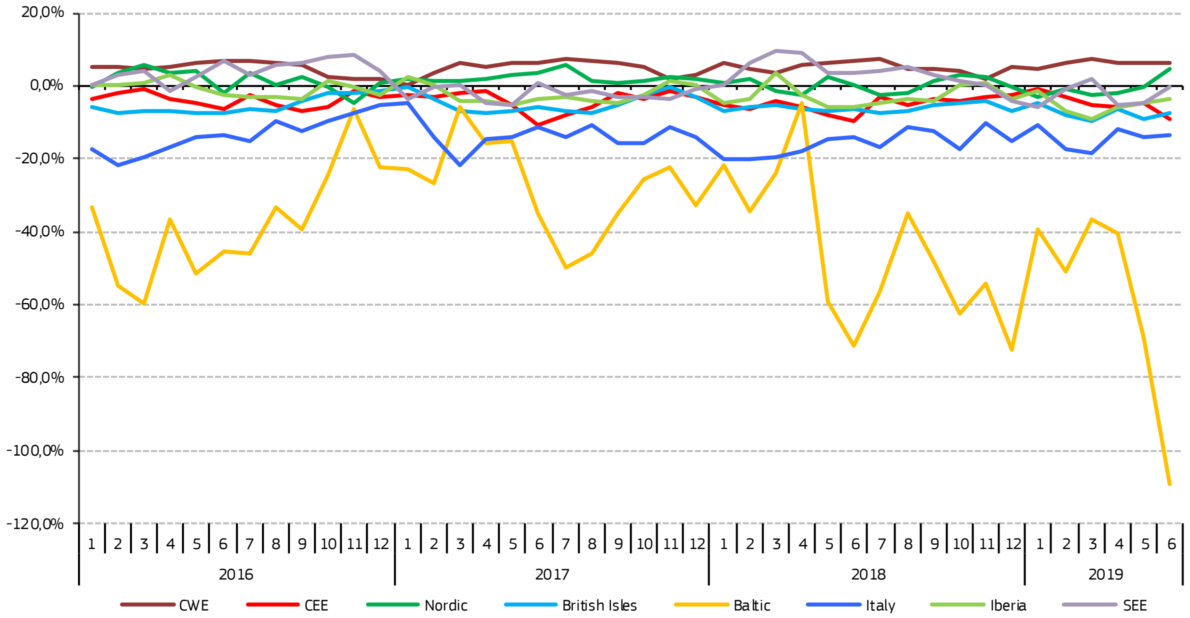
Figure 18 – EU cross border monthly physical flows by region



Key to country distribution in regions: CWE (AT, DE, BE, NL, FR, CH), CEE (CZ, HU, PL, SK, SI, HR), Nordic (DK, SE, FI, NO), Baltic (LT, LV, EE), Iberia (ES, PT), SEE (BG, GR, RO, RS, BA, ME, MK, AL), British Isles (UK, IE), Apennine Peninsula (IT, MT). Source: ENTSO-E, TSOs

- **Figure 19** compares net cross border flows to regional power generation to give a better comparative perspective on the flows and their size. Positive values indicate a net exporter. In Q2 2019 the position of the Baltic region continued to worsen as it imported an amount equivalent to roughly 73% of domestically generated electricity (compared to 45% in Q2 2018). In June, for the first time ever, more electricity was imported than produced locally. High shares of imports indicate difficulties facing domestic generation assets or more favourable price conditions in the neighbouring areas. High CO2 prices, which negatively affect the competitiveness of fossil-based power plants in the Baltic region, played a crucial role in the developments there (see **Figure 29**).
- In terms of relative shares, Italy retained the position of the second biggest importer relative to its production. For other regions the net cross border position was less than 10% compared to domestic production. It is noteworthy that outflows from the CWE region, which is a significant exporter in absolute terms, are not large in relation to its total production. In Q2 2019 the net exports were equal to 6.5% of local generation.

Figure 19 – The ratio of the net electricity exporter position and the domestic generation in the regions



Key to country distribution in regions: CWE (AT, DE, BE, NL, FR, CH), CEE (CZ, HU, PL, SK, SI, HR), Nordic (DK, SE, FI, NO), Baltic (LT, LV, EE), Iberia (ES, PT), SEE (BG, GR, RO, RS, BA, ME, MK, AL), British Isles (UK, IE), Apennine Peninsula (IT, MT). The -100% level means the same amount of electricity is imported as produced domestically. Source: ENTSO-E, TSOs, Eurostat, DG ENER calculations

3 Regional wholesale markets

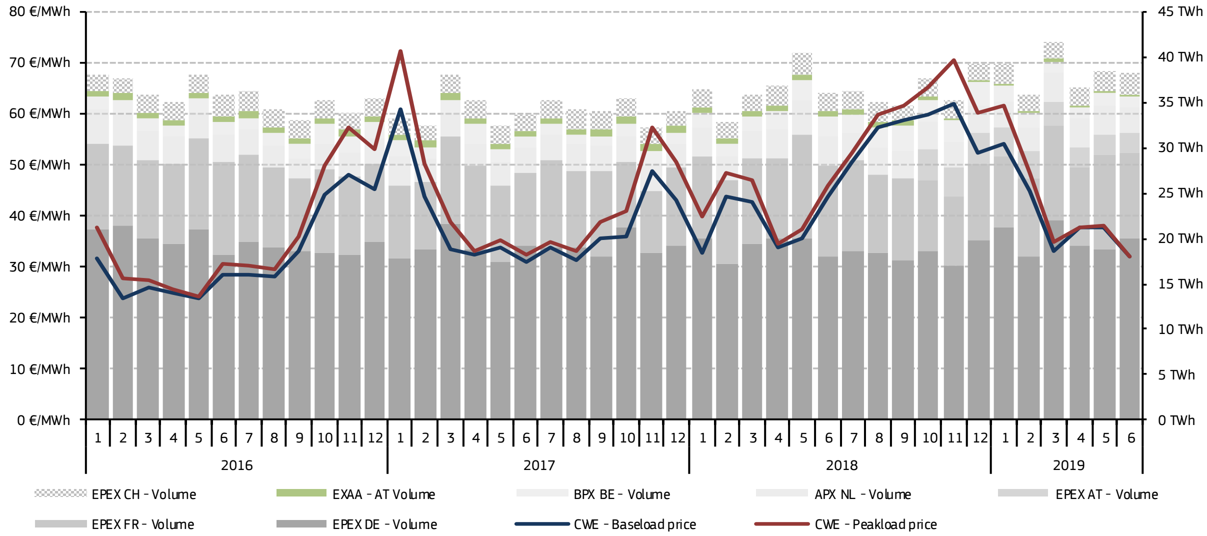
3.1 Central Western Europe (Austria, Belgium, France, Germany, the Netherlands, Switzerland)

- In April 2019 the monthly average baseload electricity prices in the CWE region rose to 38 €/MWh from 33 €/MWh in the previous month as CO2 and fuel prices climbed up, wind availability retreated from very strong March levels and solar generation only occasionally filled the gap (**Figure 20**). The established supply-demand balance endured in May, leaving the monthly average unchanged. June saw falling gas and coal prices together with record solar output across the region push the average baseload price down to 32 €/MWh, despite a short heatwave at the end of the quarter. Average peakload prices moved in tandem with their baseload peers, with negligible difference between the two, as is usually the case in Q2, thanks to ample solar generation.

- Due to its growing capacity, solar generation's rising importance in the CWE region was on display in Q2 2019, especially in June when the summer arrived with full force. In Germany June was the first month in which PV panels provided the biggest source of power, as output rose 21% year-on-year to 7.16 TWh thanks to more than 2 GW of new installations added in the first half of the year and plentiful sunshine. The peak was reached on June 29 at 33 GW – a new hourly record. At that point, between 13:00 and 14:00, solar energy covered more than half of German consumption.[4]

- June also saw a number of exceptional grid situations in Germany that led to a significant undersupply of the system and spilled over to neighbouring countries. Large deficits in power feed-in in the grid lead to a notable drops in frequency in the European network. This resulted in an increased need for balancing energy which in the critical periods averaged more than 6 GW. As the German TSOs had contracted only half of that on the balancing market, further measures had to be taken to procure additional capacity in order to offset the imbalance between production and consumption. The situation could only by calmed down with the support of neighbouring TSOs.

Figure 20 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Central Western Europe



Source: Platts, EPEX

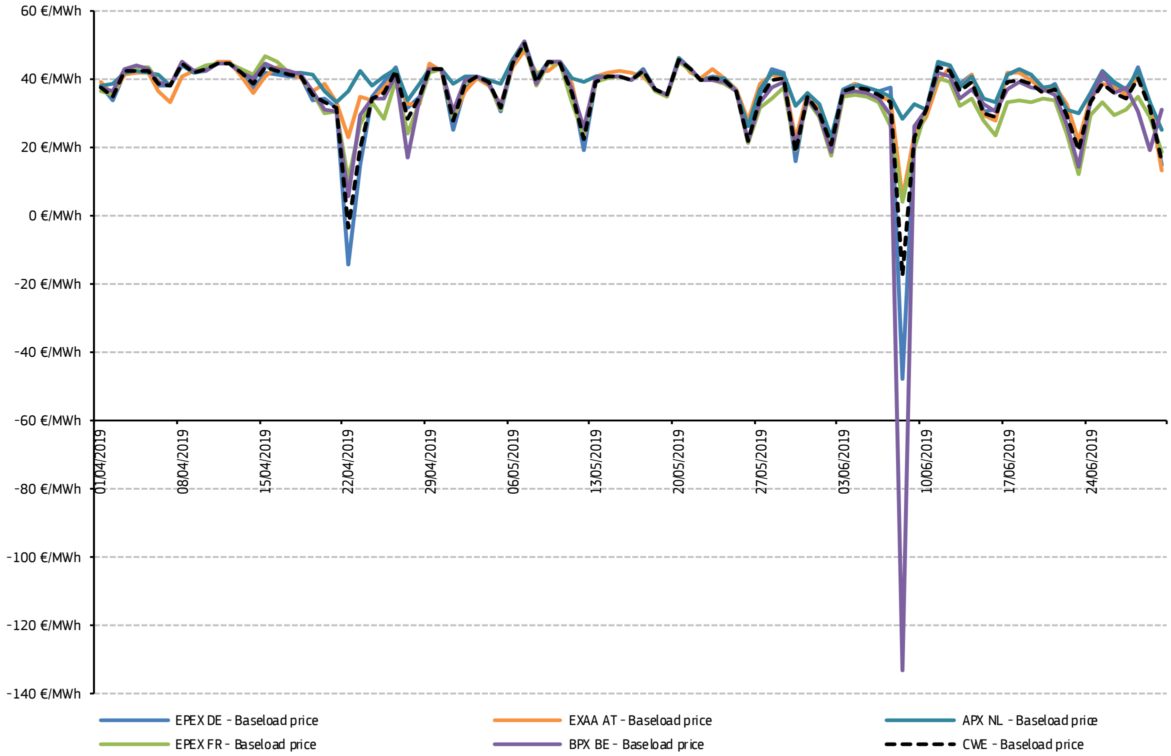
- **Figure 21** shows the average regional day-ahead prices in the reference quarter. Most of the time prices moved around 40 €/MWh, with a few dips caused by increased renewable availability and/or low demand. During Easter Monday hourly prices in Germany, France, Belgium and Switzerland ventured into the negative territory as soaring wind- and solar-powered generation met with weak holiday demand. Germany saw the biggest fall, registering negative prices all day. More volatility appeared from the second half of May due to large swings in wind

[4] *Based on data from ENTSO-E and Frauenhofer ISE.*

generation in Germany. In France, increased nuclear, renewable and gas-fired output compensated for reduced hydro availability and strong demand. Chilly weather boosted French power load by some 2 GW to the highest level of May heating demand in seven years.

- In the last month of the quarter a cascade of events that started with a technical glitch during the Epex Spot day-ahead auction on Friday, June 7, rocked the regional markets. After two unsuccessful attempts to carry out the auction at central level, the Dutch, Belgian, French, German, Austrian and British markets decoupled and, as a fall-back procedure, local auctions were organised instead with cross-border capacities at several links allocated explicitly through shadow auctions. This distorted cross-border flows and affected wholesale prices. The most extreme impact was felt in Belgium, where the first local auction rendered a price above 2000 €/MWh, attracting large inflows from France and the Netherlands. When it later emerged that the results were based on an incomplete order book and a second auction took place, the excess power load in the system combined with good wind and solar forecast and low weekend demand to push the prices deep in the negative territory (-133.6 €/MWh). Meanwhile, good renewable output and holiday consumption levels exerted similar pressure on the day-ahead prices in Germany which sank to -47.6 €/MWh on average, the lowest level since Q2 2018. The episode demonstrated the benefits of market coupling and the possible effects of IT failure at one of Europe's most important exchanges.
- In the second half of June, prices in France moved noticeably lower than the rest of the region on the back of improved hydro output and strong wind and solar generation which handily covered demand peaks during the heatwave at the end of the quarter.
- During the reference quarter, the price premium of the Austrian day-ahead market over its German peer decreased significantly (to 0.94 €/MWh compared to 4.12 €/MWh in Q1 2019 on a daily average basis), even turning negative on 37 out of 91 days of the quarter as good wind generation and healthy hydro stocks in Austria kept a lid on local contracts and high CO2 prices increased production costs of the German coal fleet. In fact, June was the first month in five years in which Germany imported more electricity than it exported, signalling wider effects of more expensive emission allowances on the generation base in the CWE region. In another sign of changing conditions on the market, the closure of a 357 MW hard coal unit at Dürnrohr, Austria, was brought forward by six years to this autumn. The plant is one of two remaining coal units in the country. The other, a 250 MW unit at Mellach, is scheduled for retirement next year.

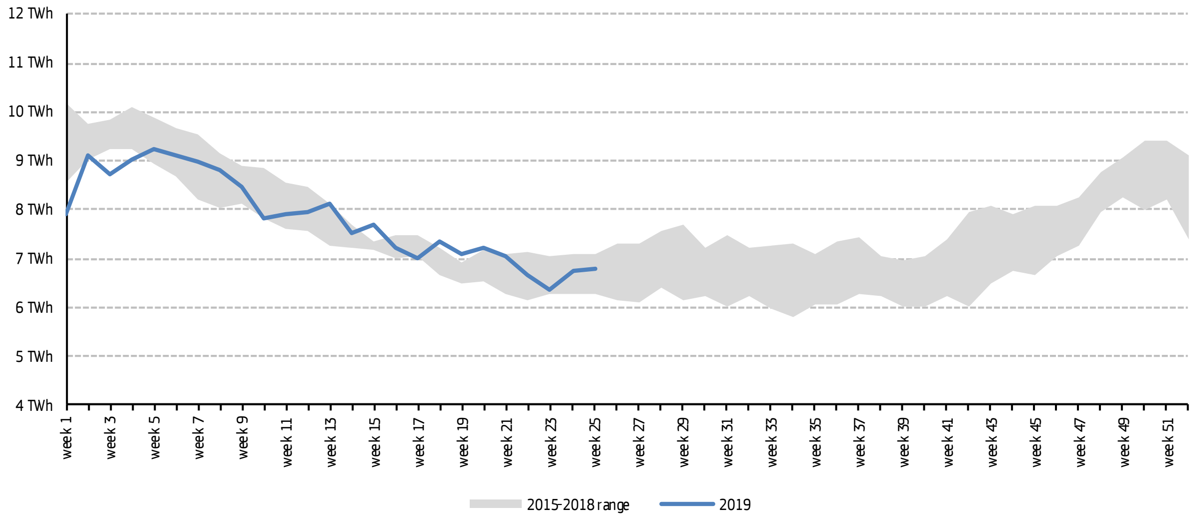
Figure 21 – Daily average wholesale power prices in the CWE region in Q2 2019



Source: Platts.

- As shown in **Figure 22** the French nuclear generation was strong in Q2 2019, increasing by 2.3% compared to the same quarter last year and helping to compensate for weak hydro output amid increased demand. Nuclear load peaked in early April at 49 GW during a short-lived cold snap. At weekends in June, on the other hand, the load fell to as low as 26-27 GW, demonstrating increased flexibility of the nuclear fleet and its ability to adapt to lower demand and avoid negative pricing. Seven out of the total of 58 French reactors are planned to undergo extended overhauls this year, six of which were ongoing during the reference quarter. In Belgium, nuclear-powered generation increased notably by 40% in Q2 2019 compared to the same quarter last year as Tihange 3 and Doel 1 and 2 reactors returned to operation earlier in the year. Net electricity imports in Belgium decreased significantly as a result compared to previous year.

Figure 22 – The weekly amount of generated nuclear electricity in France

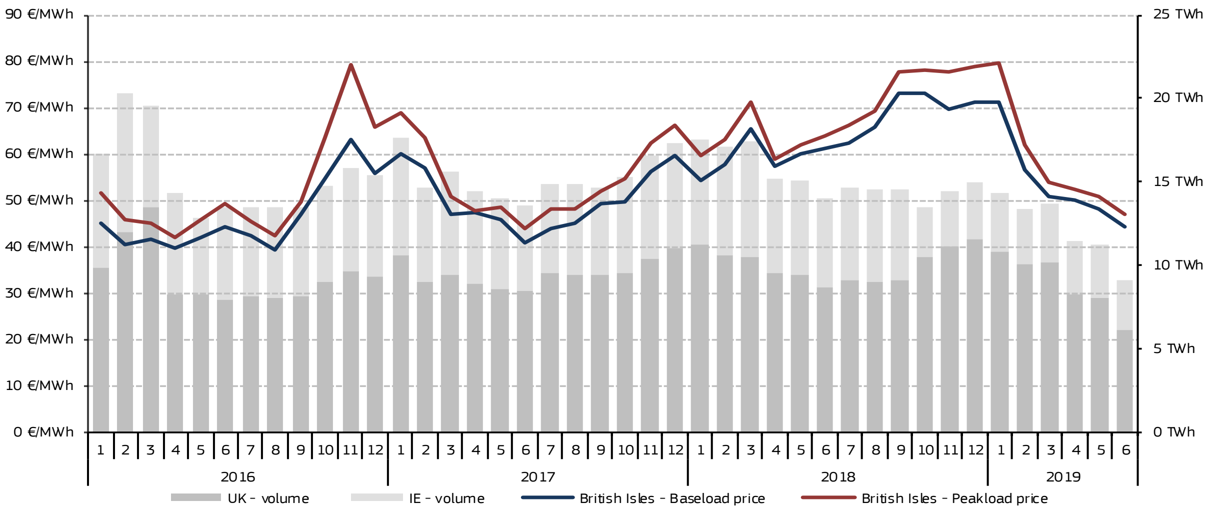


Source: ENTSO-E

3.2 British Isles (UK, Ireland)

- **Figure 23** informs about the monthly volumes and prices on the day-ahead markets in the United Kingdom and Ireland. In the reference quarter both baseload and peakload prices continued in their decline that started at the beginning of the year, pushed down by falling gas prices, good wind generation and feeble demand. Average monthly baseload prices went down by 14%, while average monthly peakload prices fell by 15% during the quarter. Compared to Q2 2018, the average baseload price declined by 21% in the reference quarter.
- Trading day-ahead activity was record low in both markets, especially towards the end of the reference period. Compared to the same quarter last year, overall volumes fell by 28% in Q2 2019.

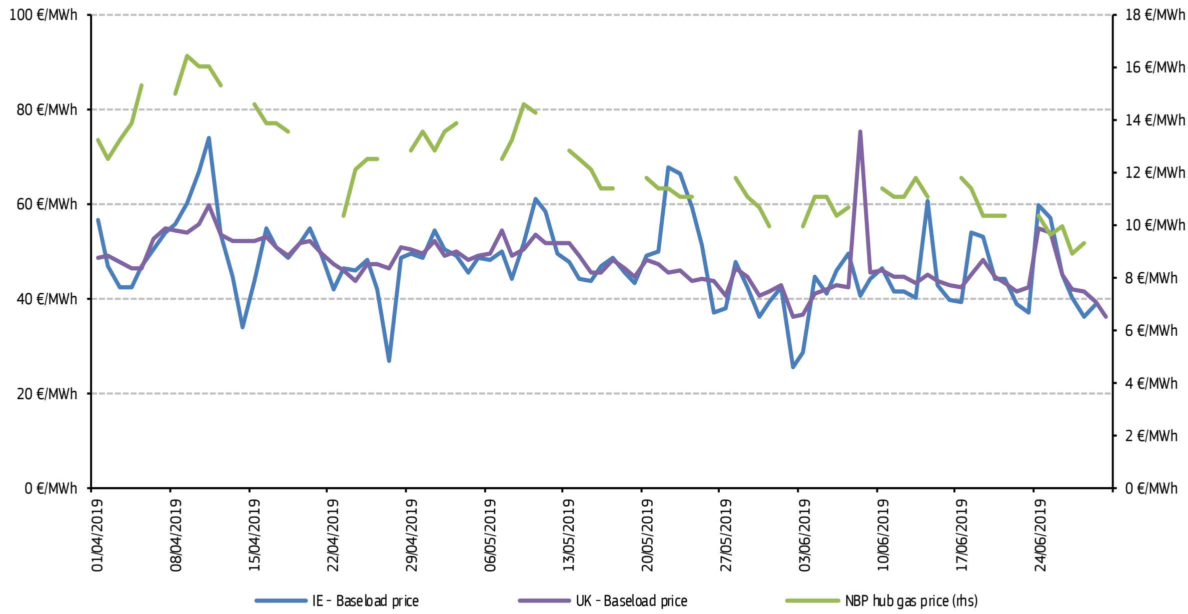
Figure 23 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in the UK and Ireland



Source: Nordpool N2EX, SEMO, Utility Regulator

- **Figure 24** shows that in Q2 2019 day-ahead baseload electricity prices in the UK (N2EX) and on the island of Ireland (ISEM) responded to falling demand and followed the general trend of decreasing prices of gas, which is the fuel that tends to set marginal electricity generation costs in both countries. The UK contract mostly stayed between 40 and 55 €/MWh, occasionally dropping below the band thanks to good wind availability. The price spike from June 8 was caused by the technical glitch on the Epex Spot exchange (see **Figure 21**) which suddenly cut the UK market from the rest of the continent and reduced power inflows. Interestingly, UK's usual premium to the Dutch and French markets disappeared at times of high British wind generation and low demand during Q2 2019 and triggered reverse flows on the IFA and BritNed interconnectors.
- Prices on the all-island Irish market generally followed the UK contract, albeit with larger volatility due to fluctuations in wind generation which constitutes a more important part of the Irish power mix compared the UK, covering around 30-35% of consumption. New installations and good weather conditions contributed to a 21% year-on-year rise in the Irish wind (onshore) output during the quarter. Coal-based generation, on the other hand, suffered from negative clean dark spreads, falling by 87% year-on-year.

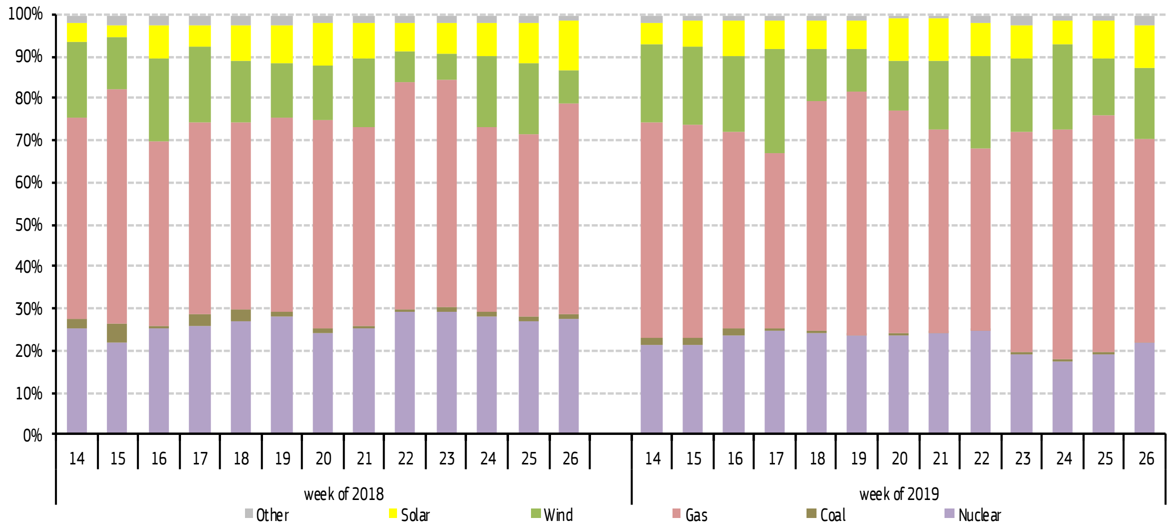
Figure 24 – Daily average baseload electricity prices in the UK and Ireland



Source: Nordpool N2EX, SEMO

- **Figure 25** compares the weekly evolution of the electricity generation mix in the UK between the reference quarter and the quarter a year before. Due to rising CO2 prices (higher than on the continent due to the carbon price support mechanism) and very competitive gas prices, coal-fired generation was almost completely priced out of the market in the second half of Q2 2019. May also witnessed the UK's longest period without coal generation since the 1880s, at 18 days and 6 hours. Extremely adverse conditions for coal in the UK are reflected in several early retirements of coal-fired power plants announced there this year and also in the fact that no coal capacities were successful in the T-1 capacity auction which took place in June to cover the 2019/2020 winter period.
- In the reference period the share of nuclear generation in the UK's electricity mix decreased to 21% compared to 25% in the same quarter last year due to extended outages. The lower availability of the British nuclear fleet accounted for 2/3 of the 7% year-on-year fall in the UK generation in Q2 2019. The share of wind generation rose from 13% in Q2 2018 to 16% in the reference quarter, on the back of growing offshore generation which registered a 35% year-on-year surge. Within the fossil fuel segment, the share of coal decreased from 1.6% to barely visible 0.6%, whereas gas increased its share from 45% to 47% year-on-year, cementing its position as the dominant source of supply, balancing out the fluctuations in wind and solar availability. The share of solar generation remained unchanged at 7% in Q2 2019.

Figure 25 – Weekly evolution of the electricity generation mix in the UK in Q2 of 2018 and 2019

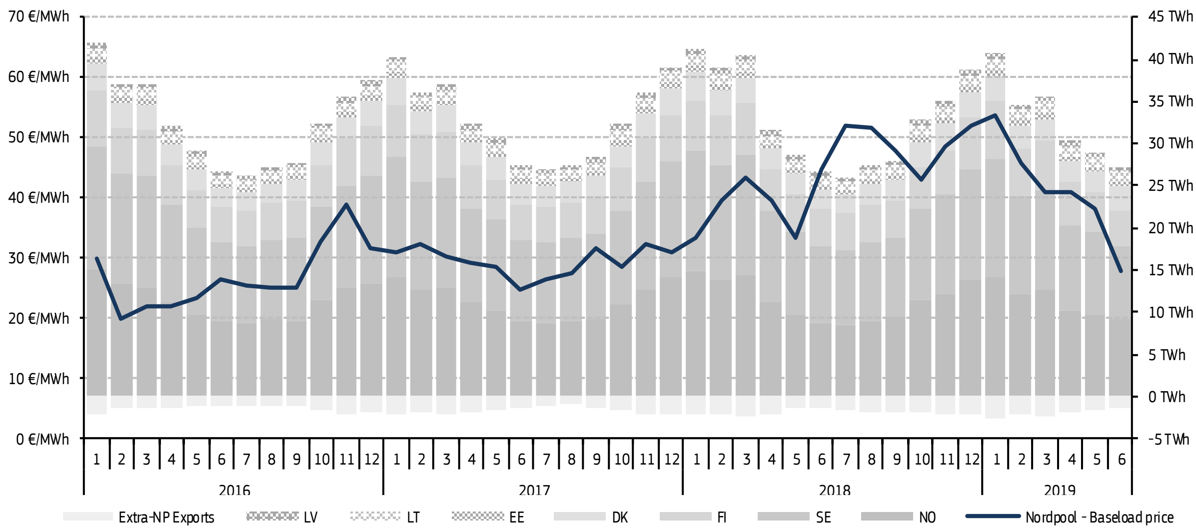


Source: ENTSO-E

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

- High precipitation levels, relatively warm weather and increasing renewable penetration in Northern Europe saw the Nord Pool average monthly wholesale price gradually decline throughout the reference quarter, moving from 41 €/MWh at the beginning to 28 €/MWh at the end of the period, as shown in **Figure 26.** In June system base-load prices were pushed down by ample wind, nuclear and hydro availability in Sweden and rarely stayed above 33 €/MWh. Thus, the region returned to more usual price levels seen before last year's extreme drought set in and influenced the market for many months.

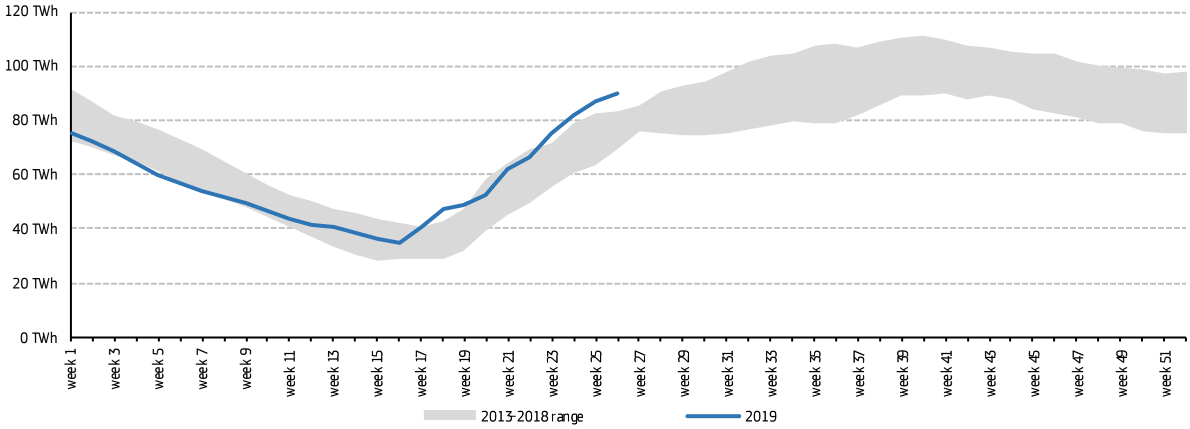
Figure 26 – Monthly electricity exchange traded volumes of and the average day-ahead wholesale prices in Northern Europe



Source: Nord Pool spot market

- **Figure 27** shows the weekly evolution of the combined hydro reservoir levels in the Nordic region (Norway, Sweden and Finland) in 2019 compared to previous six years. During the reference quarter hydro stocks in the region steadily increased at an above-average pace compared to the benchmark as heavy rains and low power demand in May and in June lifted reservoirs to record levels. Overall hydro generation in the region, however, was underwhelming during Q2 2019, dragged down by Norway's 5% year-on-year decline (1.3 TWh in absolute terms) which could not be compensated by Sweden's 5% year-on-year increase (0.7 TWh). Norwegian hydro generation was hindered mainly by a significant fall of exports to Sweden where sufficient renewable availability and stable nuclear generation kept prices comparatively low. Prospects for Norwegian electricity exports might improve with the start-up of a 1400 MW link to Germany planned for the next year. Another interconnector of the same capacity to the UK is scheduled for completion in 2021.

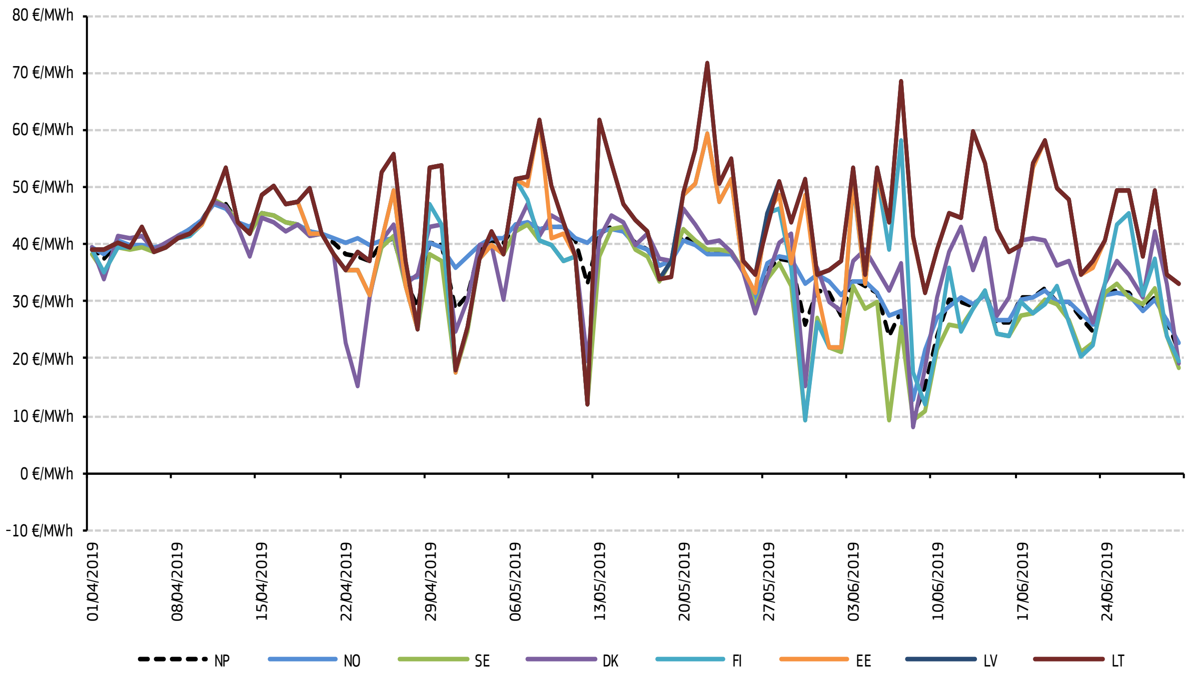
Figure 27 – Nordic hydro reservoir levels in 2019, compared to the range of 2013-2018



Source: Nordpool spot market

- **Figure 28** shows that average daily prices across Northern Europe remained relatively well-aligned in April 2019. In May and June, however, more divergence across individual markets started to appear as interconnectors couldn't fully make up for uneven generation and consumption patterns. On one hand, there were occasional price dips driven by Danish and Swedish wind generation surges. On the other hand, long-lasting price premiums began to form in the Baltic markets, with Finland sometimes joining in, mainly as a result of weakening domestic generation and lower import availability. In June, Denmark experienced prices above system average as well, as its wind farms slightly underperformed and its coal-fired capacities came under pressure of high CO2 prices. All in all, daily average prices in Q2 2019 could climb as high as 70 €/MWh in Latvia or Estonia and fall to less than 10 €/MWh in Denmark or Sweden within a short space of time.

Figure 28 – Daily average regional prices and the system price in the Nordic region

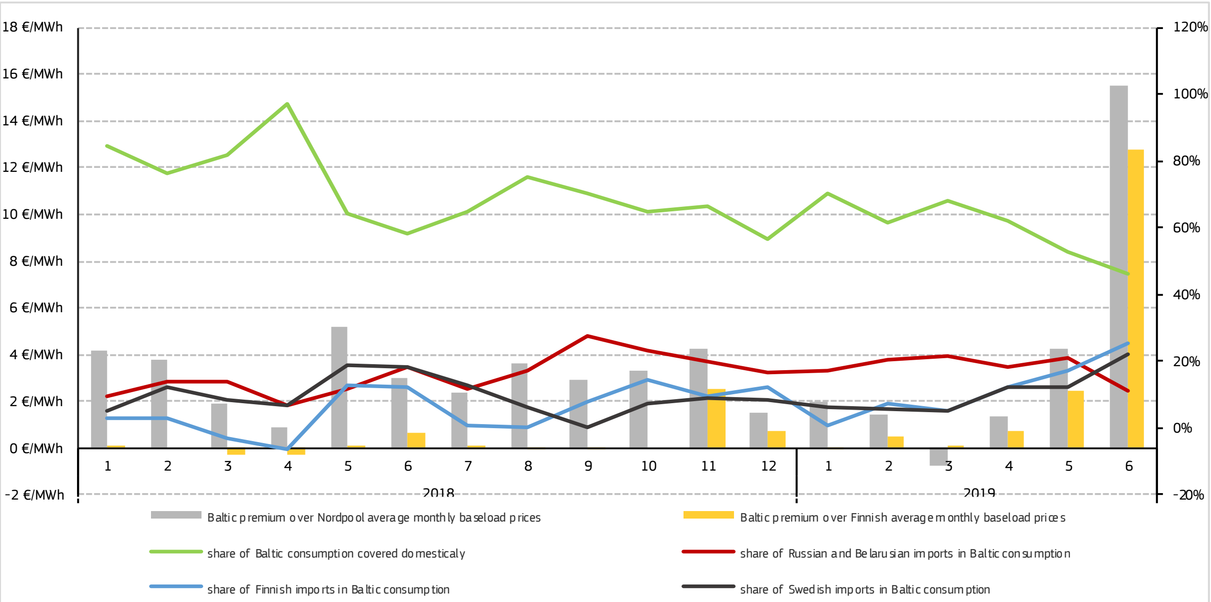


Source: Nord Pool spot market

- During most of the reference period Northern Europe remained a net electricity importer, as was the case in the previous quarter. In April and May its wholesale electricity prices were generally higher there than in some countries in Central and Western Europe. A reversal came only in May when the Nordic region, after four months, re-emerged as a net exporter. The main driving force behind the production surge was Sweden with 8.3 TWh net surplus balance in the whole reference quarter, up 25% compared to Q2 2018, on the back of good wind and hydro output. The growth in Swedish wind-powered generation was strongly assisted by a rapid capacity build-up in the sector. Last year 200 (onshore) turbines with more than 700 MW of combined capacity were added, increasing the total capacity to 7.4 GW. In 2019 new installations should bring additional 2.2 GW online, putting the size of the Swedish wind potential close to that of Italy.

- Contributing to the net importer position of the observed region were again flows from the Russian and Belarusian market to Finland and the Baltics which reached 2.9 TWh (on a net basis), down 15% compared to Q1 2019, but up 12% compared to the same quarter last year. Unlike in Q1 2019, however, these extra-EU imports were not able to fully compensate for decreases in Baltic generation which faced strong headwinds stemming from high carbon prices. In June, when the Belarusian imports slowed to a trickle and Baltic generation sank further, the Baltic baseload prices disconnected from the rest of the Nord Pool market and built significant premiums over the Nord Pool system price as well as the neighbouring Finnish market.
- **Figure 29** illuminates the situation in greater detail. The Baltic power output experienced such a fall in June that more than half the combined consumption of Lithuania, Latvia and Estonia had to be covered by imports. As electricity imports from Belarus also decreased, flows via Finnish and Swedish interconnectors were ramped up. The 15.5 €/MWh monthly average Baltic premium over the Nord Pool system price, recorded in June, was the highest since Q2 2015. The 12.8 €/MWh Baltic premium over the Finnish baseload price, recorded in June, was a six-year maximum. During some hours in May and June prices on the day-ahead market in the Baltic countries touched 200 €/MWh.
- The worsening ability of the Baltic countries to cover their consumption with domestic capacities was caused mainly by a sharp reduction in Estonian generation volumes, which fell by 62% year-on-year in June and couldn't be compensated by increases in Latvia and Lithuania. Shale oil power plants in Estonia, which usually account for 80-90% of the country's power output, have been losing competitiveness due to heightened CO2 prices and have been pushed to the margins of the electricity market. As a result, Estonian shale-oil-based generation in June dropped to one fifth of its volume in the same month last year.

Figure 29 – Price differentials between the Baltic region and Nord Pool and Finland compared to evolving shares of domestic and import coverage of the Baltic consumption



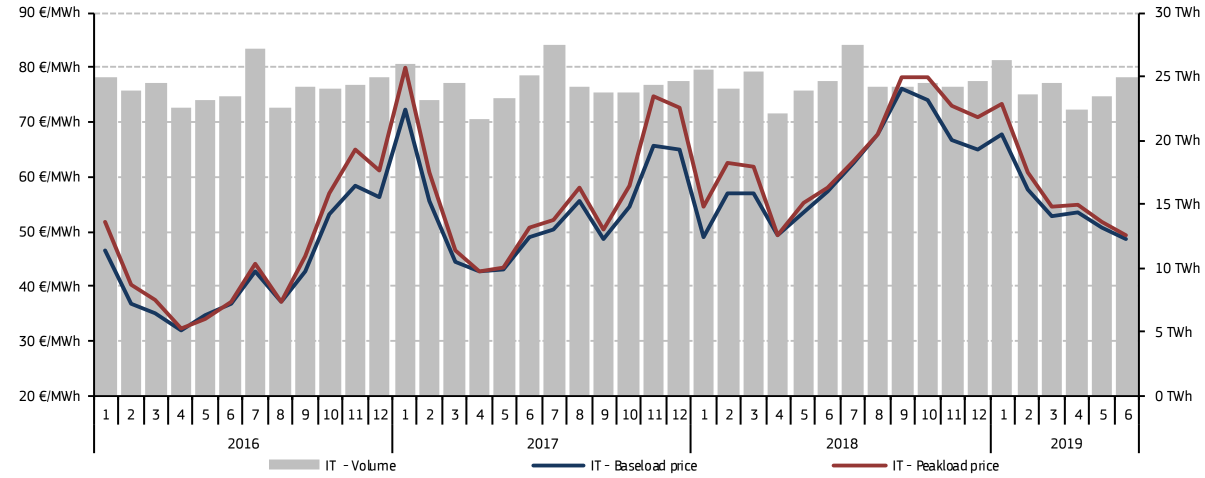
Source: Nord Pool, Litgrid, Fingrid.

3.4 Apennine Peninsula (Italy, Malta)

- The Italian monthly average baseload and peakload electricity prices (**Figure 30**) decreased in the second quarter of 2019, in line with falling gas contracts and with the rest of European wholesale markets. The baseload electricity price went down from 53.4 €/MWh in April to 48.6 €/MWh in June 2019 and was 8% lower at the end of the reference quarter compared to March 2019. The peakload electricity contract closely followed its baseload peer, finishing the quarter within a 1 €/MWh distance from it, as usual during this time of the year. Compared to Q2 2018, the average baseload price declined by 4% in the reference quarter.
- On May 20, the network in northern Italy experienced a critical situation due to a transmission curtailment on a link from Switzerland. Load shedding was averted by triggering interruptible supply contracts of large energy consumers in the Northern zone for 45 minutes. The curtailment was a result of greater than expected flows from Switzerland to Germany and unplanned load shifts within the Swiss zone that lead to an overload of parts of the Swiss grid.

- Several Italian power generators announced plans in Q2 2019 to convert a significant amount of coal-fired capacity to gas or build entirely new CCGT units. The move coincides with the planned launch of a local capacity market this year and comes in advance of a coal phase-out scheduled for 2025.

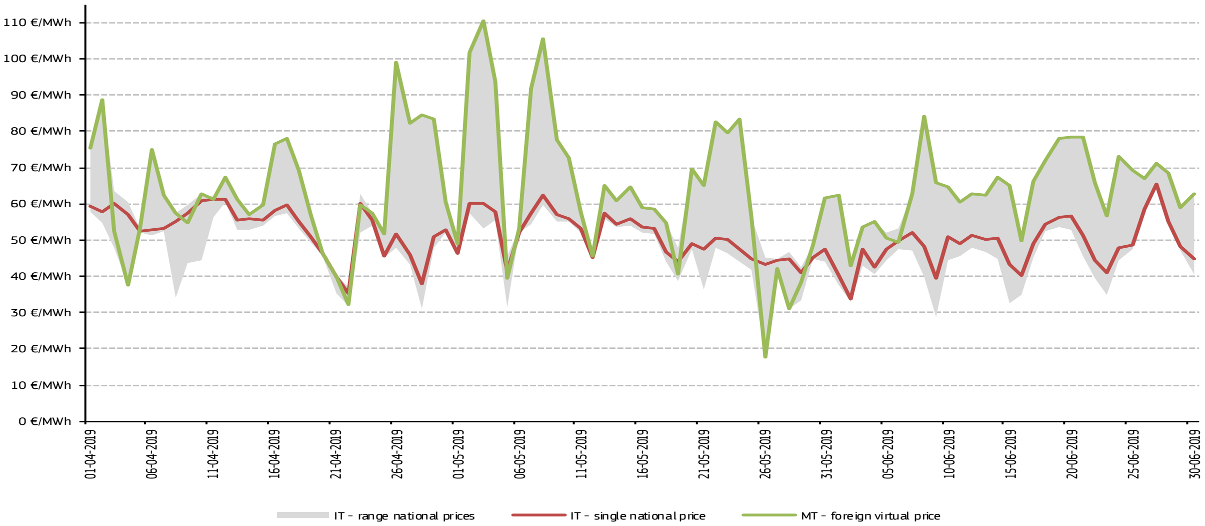
Figure 30 – Monthly electricity exchange traded volumes and average day-ahead wholesale prices in Italy



Source: GME (IPEX)

- **Figure 31** shows the daily evolution of the national average price and the range of the regional price areas in the Italian market. In the second quarter of 2019 the national average price moved mostly in a band between 40 and 60 €/MWh. In April, a temporary increase in gas prices, colder weather, low hydro reservoirs and limited interconnector capacity pushed baseload contracts towards the upper end of the spectrum and, for the first time in 11 years, even above March levels. The only exception was Easter holidays when low demand caused a dip in prices. A wet spell in the second part of May improved hydro production and eased some of the supply constraints which, combined with falling gas prices and good wind output, brought spot prices under 50 €/MWh. In June, improving hydro picture was gradually overshadowed by increased cooling demand caused by record high temperatures, with prices culminating on June 27 at the height of the heatwave.
- The Italian Power Exchange provides data on foreign price zones such as Malta, in addition to individual regional markets in Italy. The island is a net electricity importer from Italy (through Sicily) and thereby daily prices from the Italian power exchange influence the Maltese wholesale electricity market. As visible in **Figure 31**, prices in the Maltese zone in most cases form the upper boundary of the whole spectrum of Italian regional electricity prices. Price spikes at the end of April and the beginning of May were caused by unplanned plant outages and low wind output in neighbouring Sicily and reduced flows from the mainland.

Figure 31 – Daily average wholesale electricity prices in the Italian market, within the range of different area prices

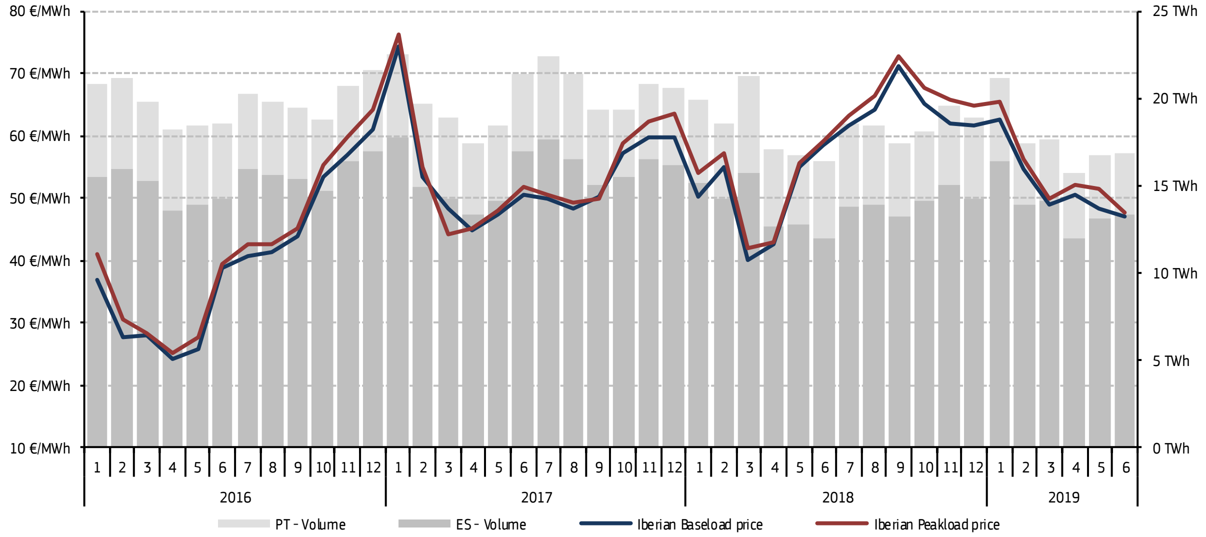


Source: GME (IPEX)

3.5 Iberian Peninsula (Spain and Portugal)

- **Figure 32** reports on the monthly average wholesale baseload and peakload contracts in Spain and Portugal. In April prices went slightly up month-on-month amid unplanned nuclear outages in Spain and low hydro output. During the rest of the reference period both baseload and peakload contracts declined thanks to lower gas prices and good wind and solar generation, finishing the quarter close from each other at around 47.5 €/MWh. Compared to Q2 2018, the average baseload price declined by 7% in the reference quarter. Compared to the previous quarter, the average baseload contract was down 12% in Q2 2019.

Figure 32 – Monthly electricity exchange traded volumes and average day-ahead prices in the Iberian Peninsula



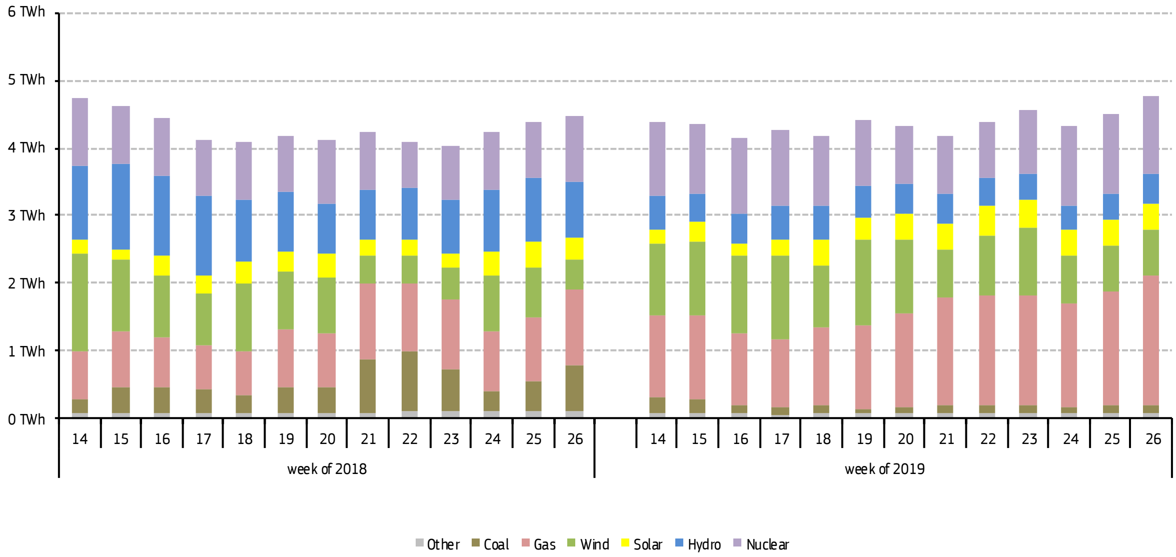
Source: Platts, OMEL, DGEG

- **Figure 33** displays the evolution of the weekly electricity generation mix in Spain during the second quarter of 2019, as well as during the same period of the previous year. The combined share of renewable electricity sources (hydro, wind, solar and biomass) reached roughly 40% on average throughout the period, the same as in the previous quarter, but 7 percentage points down compared to Q2 2018 on the back of a 50% fall in hydro generation. The share of wind-powered generation in Q2 2019, on the other hand, rose from 18% to 22%, while the share of solar increased from 6% to 8% year-on-year.

- The combined share of coal, lignite and gas in the mix went up from 30% in Q2 2018 to 35% during Q2 2019. This was driven by a significant boost in gas-fired generation which stepped in to make up for missing hydro output and increased its share from 20% to 32% year-on-year. Coal plants, in contrast, suffered under adverse market conditions and saw their share reduced from 10% to 3% year-on-year, as coal-to-gas switching intensified. Lignite-fired generation ceased completely in the reference quarter. The year-on-year improvement in competitiveness of hub-based gas in Spain was also helped by the removal of a tax on gas used by CCGT and cogeneration units last October.

- The share of nuclear energy in Spain's energy mix, at 23%, was 3 percentage points higher during the reference period than in Q2 2018 despite some unplanned outages.

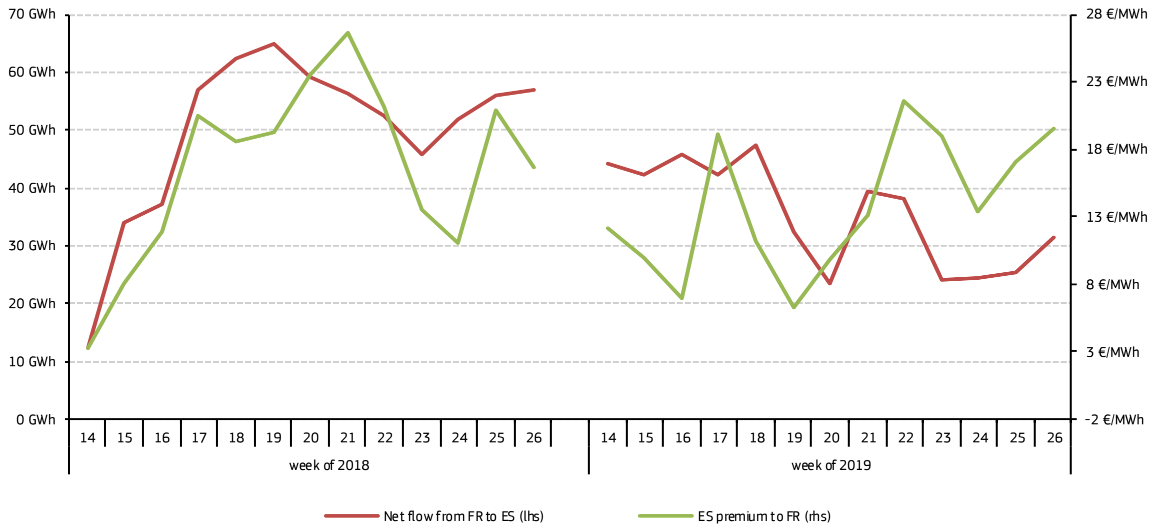
Figure 33 – Weekly evolution of the electricity generation mix in Spain in Q2 of 2018 and 2019



Source: ENTSO-E

- **Figure 34** shows that the premium of Spanish day-ahead prices over their French peers averaged 13.8 €/MWh in the reference period, down 17% from 16.6 €/MWh in Q2 2018, on the back of a significant year-on-year fall in French hydro generation. However, total net French exports to Spain registered a sharper fall in Q2 2019, decreasing by 29% year-on-year to 461 TWh as the capacity of the link between the two countries was curtailed since the second half of the reference quarter (according to data from Joint Allocation Office).
- Imports of electricity from Morocco to Spain, which increased markedly in Q1 2019 to 0.6 TWh and turned Spain into a net importer vis-à-vis its southern neighbour, went down to 0.3 TWh in the reference quarter. Compared to the total size of the Spanish market, the imports from Moroccan generation capacities (which are not covered by EU ETS obligations) remain relatively insignificant, amounting to less than half a percentage point of consumption in Q2 2019. The 1.4 GW Spain-Morocco link is the only direct interconnector between Africa and Europe at the moment. A recently signed memorandum of understanding between the two governments proposes another link which would boost the capacity to 2.1 GW by 2026. Morocco and Portugal are set to construct an undersea electricity cable connecting them with a capacity of 1GW. Italy and Tunisia signed an agreement in April to proceed with a proposed 600 MW link between Sicily and Cap Bon peninsula on the Tunisian coast.

Figure 34 – Weekly electricity flows between France and Spain and price differentials between the two markets

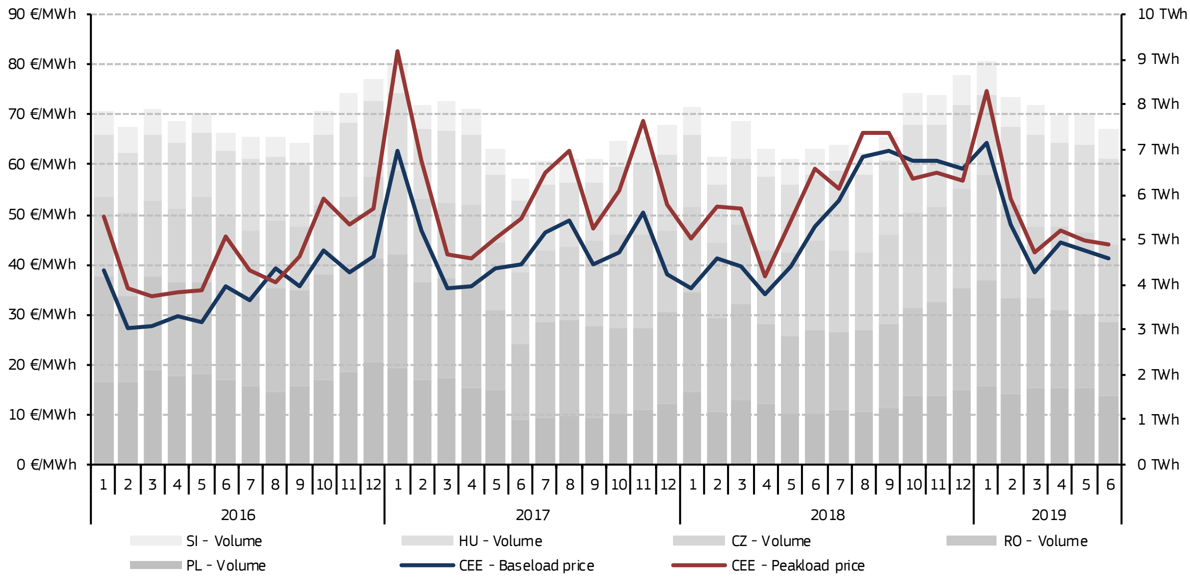


Source: ENTSO-E, OMEL, Platts

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

- **Figure 35** shows that average monthly prices for baseload and peakload power in Central Eastern Europe have followed a similar trajectory as other European regions in the second quarter of 2019, first rising by 16% month-on-moth in April amidst increases in CO2 and gas prices and import capacity reductions, and consequently falling on the back of easing supply constraints and lower input prices. However, contrary to the CWE region, UK, Italy or Spain, the average monthly CEE baseload prices finished the reference quarter higher than where they were in March, above 41 €/MWh. Generally lower renewable penetration in the region could be one of the explanations. Peakload prices followed their baseload peers, keeping their premium under 3 €/MWh.
- When compared to the previous Q2 the average baseload price in the reference quarter went up 6% to 42.9 €/MWh. Compared to Q1 2019, however, the average monthly price in the reference quarter fell by 15%.
- The region remained a net importer of electricity in the reference quarter, but to a lower extent than in Q2 2018, with net inflows reaching 5.1 TWh in Q2 2019. Germany, Austria and Ukraine were the largest sources of inflows.

Figure 35 – Monthly electricity exchange traded volumes and average day-ahead prices in Central Eastern Europe (CEE)

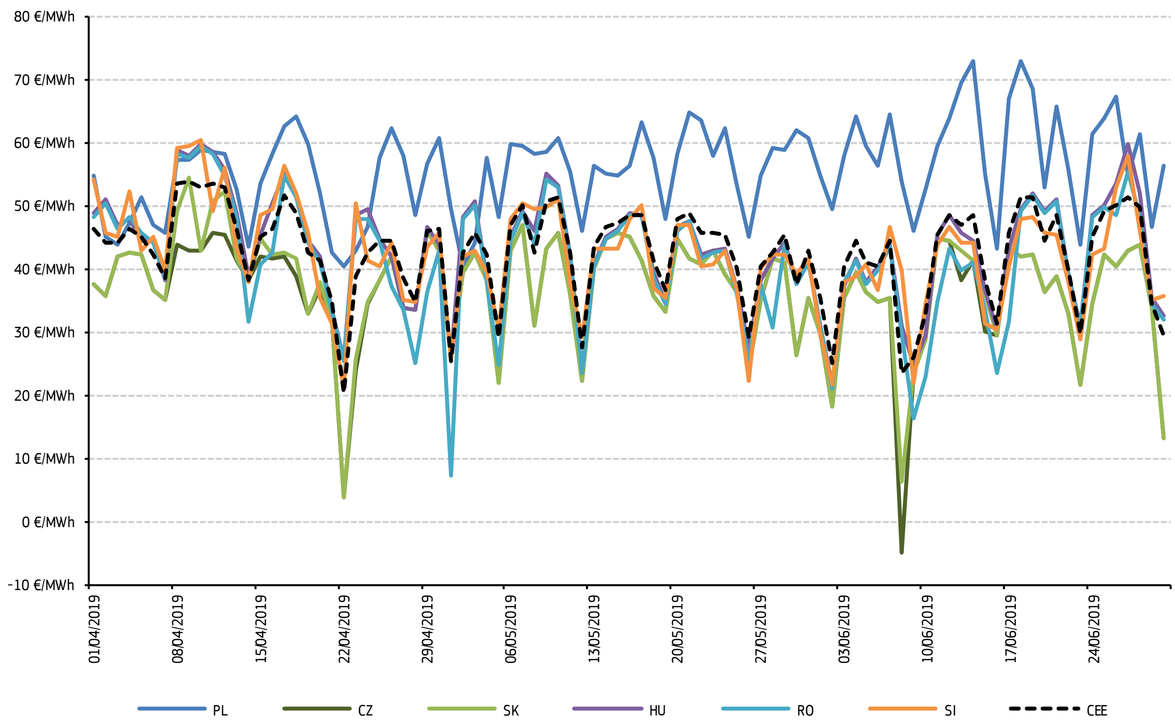


Source: Regional power exchanges, Central and Eastern Europe (CEE)
CEE: PL, CZ, SK, HU, RO, SI

- **Figure 36** reports that daily average wholesale prices in the CEE region during the reference quarter were relatively well correlated, with the exception of Poland which built a premium over the other markets that grew with each month of the quarter (from 9 €/MWh on average in April to 13 €/MWh in May to 18 €/MWh in June). The expanding gap could be explained by high CO2 prices, which due to the specifics of the local power mix affect the Polish market disproportionately more than the rest of the region. Limited cross-border capacity curbed additionally by maintenances, unimpressive wind performance, and rising demand could have played their part too.
- With the exception of Poland, average daily prices in the region mostly moved between 20 and 50 €/MWh in the reference quarter. The larger price dip from April 22, which was most pronounced in Czechia and Slovakia, relates to low Easter holiday demand which was met by ample renewable output. The other significant price fall, from June 8, was the result of the decoupling of Western European markets (see **Figure 21**) which combined with a sunny and windy weekend and spilled over from Germany mainly to Czechia and Slovakia, causing local hourly prices to go negative for several hours (see **Figure 13**). On the other side of the price spectrum, wholesale contracts breached the 70 €/MWh barrier in Poland on several occasions in the middle of June as heatwaves drove local power demand to new records. The impact was contained thanks to the raised import capacity at the Czech and German links, increasing PV penetration and the start-up of two 900 MW coal-fired units at Opole.
- Nuclear generation, which generally constitutes a third of the combined power mix of Czechia, Slovakia, Hungary, Romania and Slovenia, was up 4% year-on-year, broadly in line with a 3.2% increase in total generation during Q2 2019. High precipitation levels in the Danube basin in May and June helped hydro output in Slovakia and Romania increase by 45% and 16% respectively in Q2 2019 compared to Q2 2018. Some coal-to-gas and lignite-to-gas switching took place in Poland, Czechia, Slovakia and Hungary. Gas-fired generation in the four coun-

tries in Q2 2019 rose by 1.8 TWh year-on-year, whereas the combined coal and lignite output fell by 1.5 TWh year-on-year. Romania was an exception in this regard, registering a 0.5 TWh year-on-year fall in gas generation in the reference quarter, which had to be partly covered by increased imports from Ukraine. Hungarian imports of Ukrainian electricity in Q2 2019, at 1.2 TWh, were little changed from last year's Q2. At the end of May, Hungary saw imports meeting as much as 50% of total consumption as maintenance and unplanned outages at the Paks nuclear plant and Matra lignite plant limited domestic generation. The impact on wholesale prices was negligible, though, due to ample interconnection capacity and large flows from neighbouring markets.

Figure 36 – Daily average wholesale power prices in the CEE region



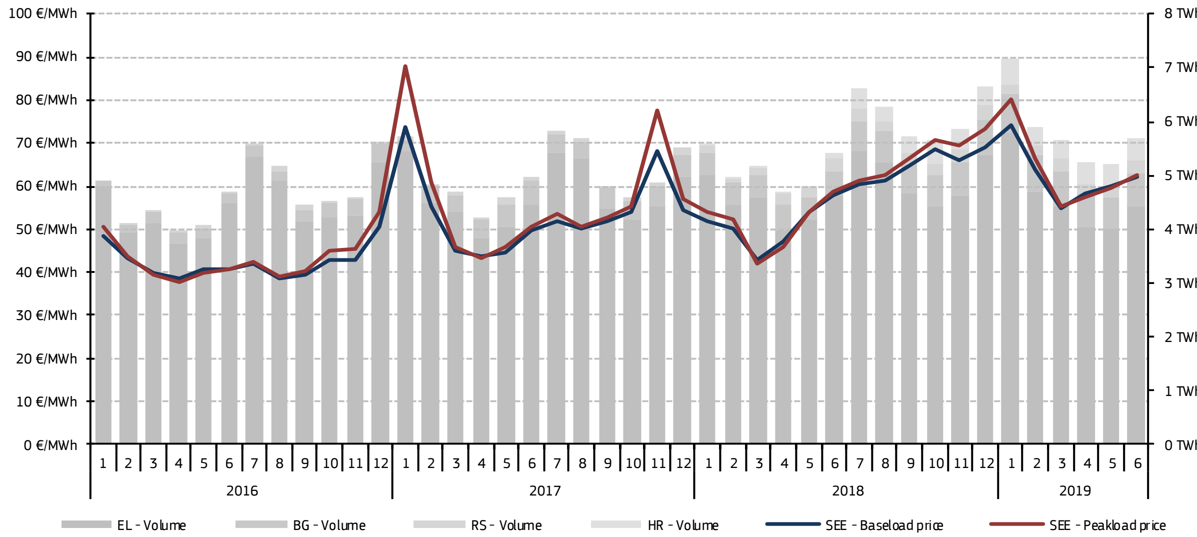
Source: Regional power exchanges, Central and Eastern Europe (CEE)
CEE: PL, CZ, SK, HU, RO, SI

3.7 South Eastern Europe (Bulgaria, Croatia, Greece and Serbia)

- **Figure 37** shows that wholesale markets in the SEE region took a different path than the rest of the continent in Q2 2019, with baseload and peakload contracts rising throughout the reference period. From its trough in March at 55 €/MWh, the average monthly baseload price climbed to 62 €/MWh in June. The increase in April spread universally across all four markets on the back of rising fuel and CO2 prices and low hydro generation, but in May and June it was exclusively driven by Greece which suffered from reduced lignite generation and had to ramp up imports. Since the regional prices index is volume-weighted and Greece has by far the largest and most liquid market, it singlehandedly swayed the regional trend, even though Bulgaria, Croatia and Serbia registered decreases in their average monthly prices in May and June thanks to improving hydro conditions. The regional baseload contract in the whole of Q2 2019 reached 60.1 €/MWh on average, up 13% compared to Q2 2018.
- The average Greek monthly peakload price stayed under its baseload peer throughout the reference quarter, with the discount moving between 1 and 2 €/MWh. The rest of the region saw the more traditional peakload price premiums in the range of 2-6 €/MWh.
- As in the previous quarter, day-ahead Greek electricity wholesale prices were decoupled from the rest of the region, as shown in **Figure 38**, and stayed 16-24 €/MWh higher on average than in neighbouring markets in Q2 2019. High CO2 prices and relatively uncompetitive supply contracts weighed down the output of Greek lignite plants (-0.6 TWh year-on-year), while their gas-fired competitors boosted generation by 0.5 TWh thanks to low input costs. The diverging fortunes of gas- and lignite-fired generators are reflected in the planned investments in new capacity. Five applications for new gas units with a combined capacity of 3460 MW were recently submitted to the Greek regulator. Day-ahead prices in the rest of the region displayed a relatively high level of convergence in Q2 2019, with Bulgaria registering more volatility.

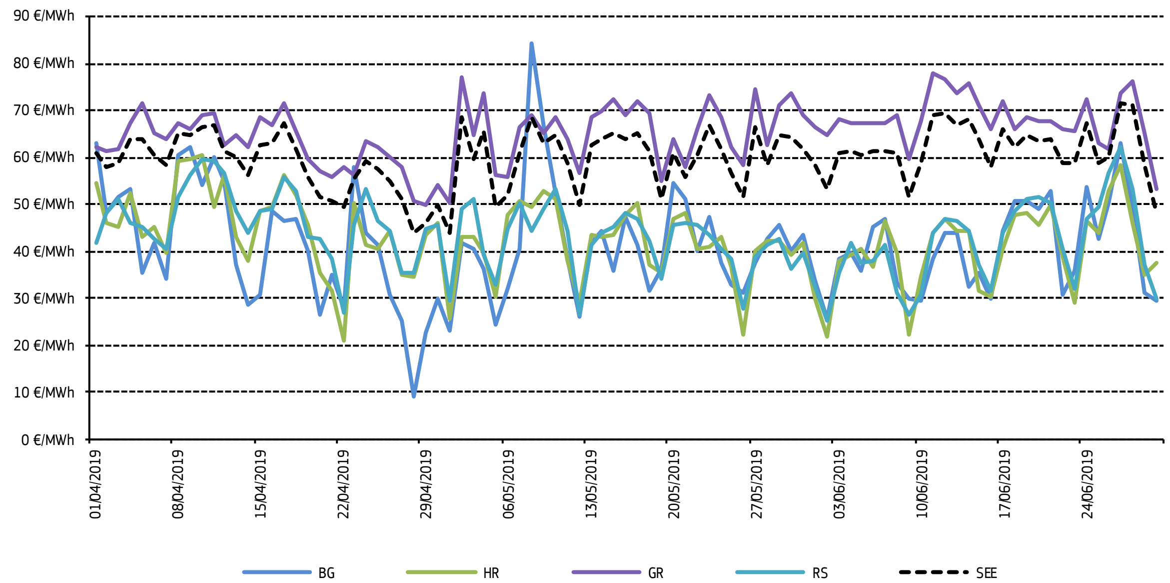
- Changes of the Bulgarian regulatory framework in the reference quarter have removed fees for the export and import of electricity, incentivizing more cross-border trading activity and creating opportunities for market coupling with neighbouring countries and increased price convergence across the region. In another major legislative change, the mandatory participation of larger renewable generators on the liberalized market was introduced. This effectively brought 750 MW of renewable capacity to the free market and is expected to improve competition and liquidity on the local power exchange. It also means that weather patterns will start to influence Bulgaria's spot prices more than before.
- The average Bulgarian baseload electricity price in Q2 2019 increased by 22% year-on-year to 41.2 €/MWh. A similar 17% rise occurred in Greece where the average baseload contract reached 65.5 €/MWh. The average Serbian baseload price rose by 8% year-on-year to 43.4 €/MWh, while the conditions on the Croatian market stayed unchanged at 42.5 €/MWh in the reference quarter.
- Bulgaria is traditionally a net exporter of electricity. In Q2 of 2019, a volume of 0.7 TWh was transferred from Bulgaria to Greece (up from 0.5 TWh in Q2 2018) and 0.3 TWh from Bulgaria to Serbia (unchanged year-on-year). Some additional volumes from Bulgaria flowed to Greece via North Macedonia and Turkey.

Figure 37 – Monthly traded volumes and prices in South-Eastern Europe (SEE)



Source: IBEX, LAGIE, OPCOM, SEEPEX

Figure 38 – Comparison of daily average day-ahead prices in Bulgaria, Croatia, Greece and Serbia



Source: IBEX, LAGIE, SEEPEX, CROPEX

4 Retail markets

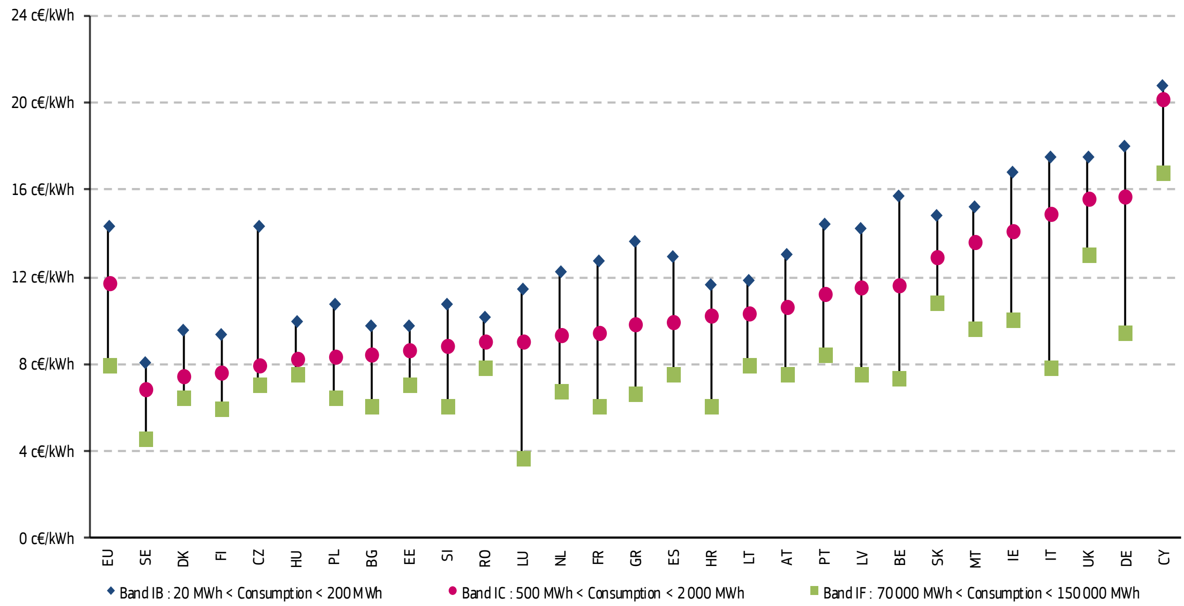
4.1 Retail electricity prices in the EU

- **Figures 39 and 40** display estimated [retail prices]() in June 2019 in the 28 EU Member States for industrial customers and households. Prices are displayed 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 MWh).

- Median industrial consumers (band IB) paid the highest prices in Germany (18.0 c€/kWh), Italy and UK (both 17.4 c€/kWh), followed by Ireland and Belgium (16.8 and 15.7 c€/kWh, respectively), apart from the non-interconnected island system of Cyprus. The lowest prices were assessed to be in Sweden (8.0 c€/kWh) and Finland (9.3 c€/kWh). 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 (13.0 c€/kWh) followed by Slovakia, Ireland and Germany. Luxembourg (3.7 c€/kWh) had the lowest prices, followed by Sweden and Finland. The ratio of the highest to lowest price for large industrial consumers was around 3:1 for this consumer type (excluding Cyprus).

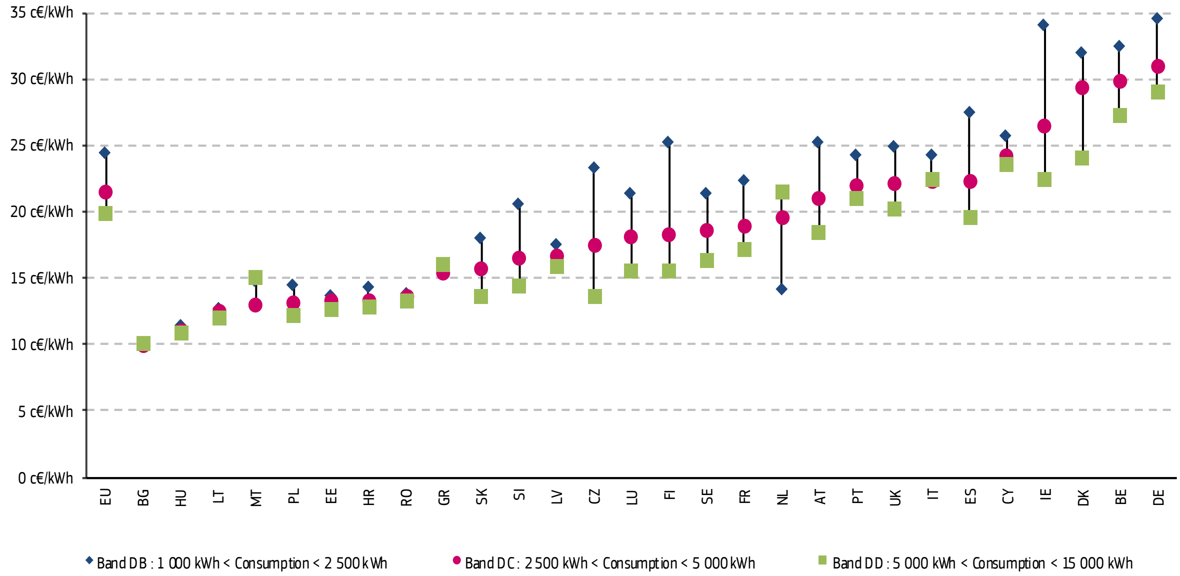
- In June 2019 Germany (31.0 c€/kWh) was assessed as having the highest median household (band DC) price for electricity consumers, having overtaken Belgium (30.0 c€/kWh), and with Denmark (29.5 c€/kWh) taking the third place. The lowest price was calculated for Bulgaria (10.1 c€/kWh). Household electricity prices are 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 the largest to smallest price is higher for this consumer class, exceeding 3:1.

Figure 39 – Industrial electricity prices, June 2019 – without VAT and recoverable taxes



Source: Eurostat, DG ENER

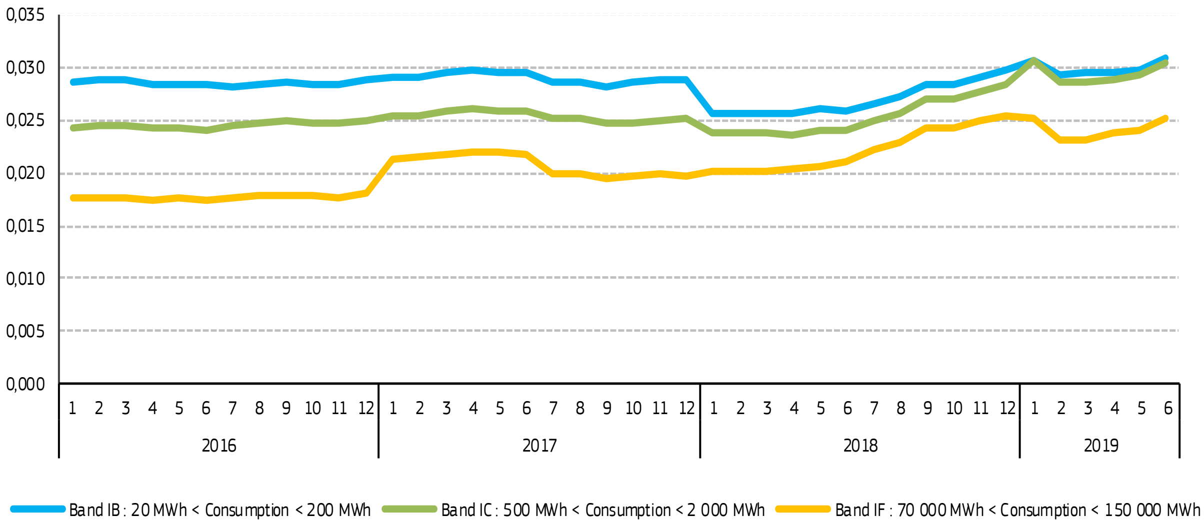
Figure 40 – Household electricity prices, June 2019 – all taxes included



Source: Eurostat, DG ENER

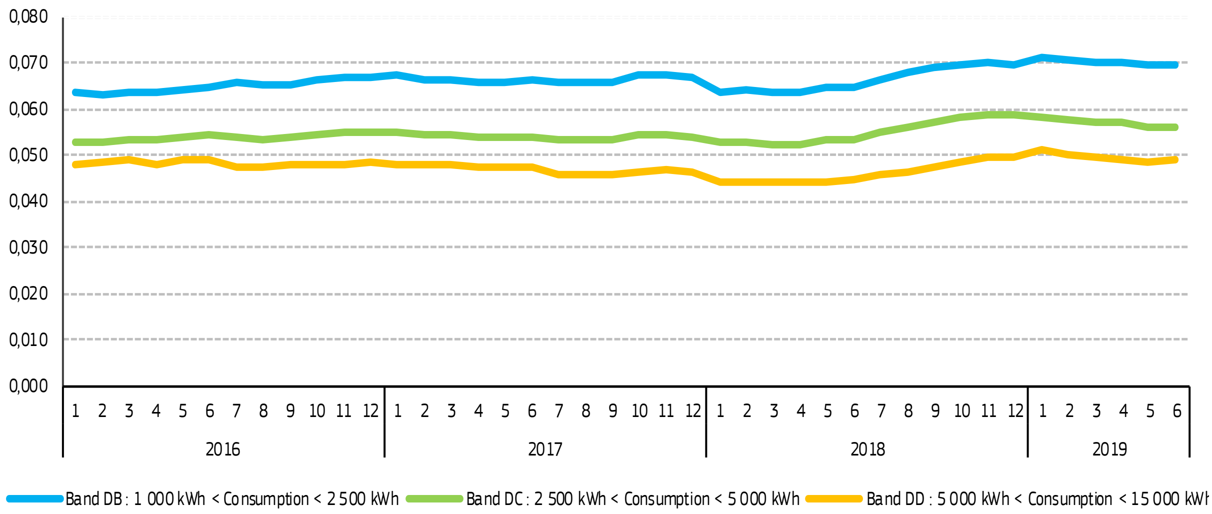
- **Figures 41 and 42** display the convergence of retail prices across the EU over time, by depicting their standard deviation. After a brief pause at the start of 2019, end-user prices for all three levels of industrial consumption showed increasing divergence between April and June 2019, reaching record highs in all segments at the end of the reference quarter. In the case of smaller industrial consumers the divergence touched levels last seen in 2015. For medium-sized and large industrial companies customers the differences in power prices across Europe in Q2 2019 were the largest on record. The energy component, which was largely responsible for dispersion for all three levels of consumption, accounts for less than 40% of prices paid by industrial consumers with small and medium volume consumption. The increasing divergence of individual retail markets to a certain extent mirrors the developments in the respective wholesale markets (see **Figure 7**).
- The evolution of household price convergence was less volatile as such prices are more impacted by regulated elements (network charges, taxes and levies). The differences in prices for the small household consumption band remained broadly unchanged, while in the case of medium-sized and large households the divergence of prices slightly decreased during Q2 2019.

Figure 41 – Standard deviation of retail electricity prices in the EU Member for industrial consumers



Source: Eurostat, DG ENER

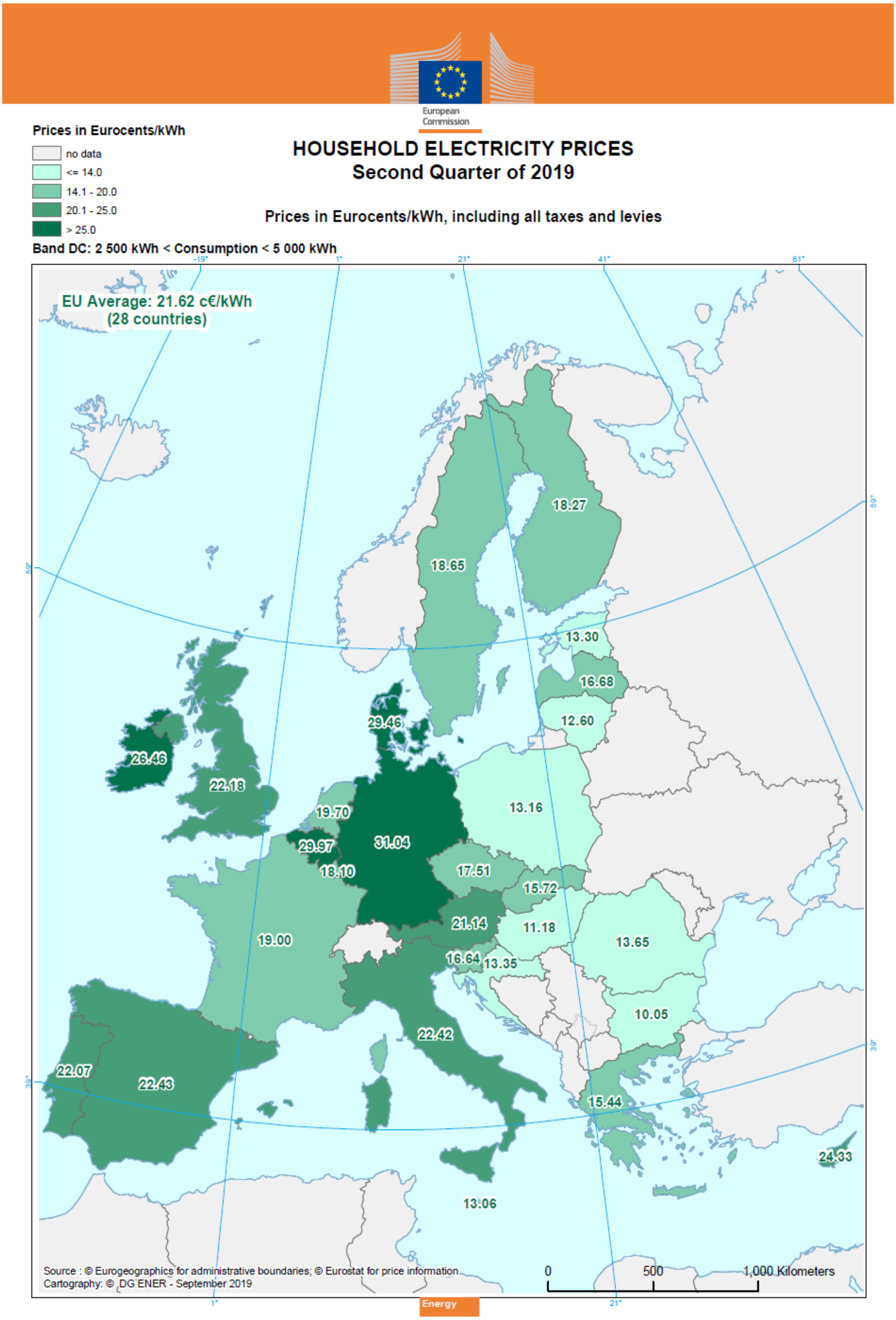
Figure 42 – Standard deviation of retail electricity prices in the EU Member States for household consumers



Source: Eurostat, DG ENER

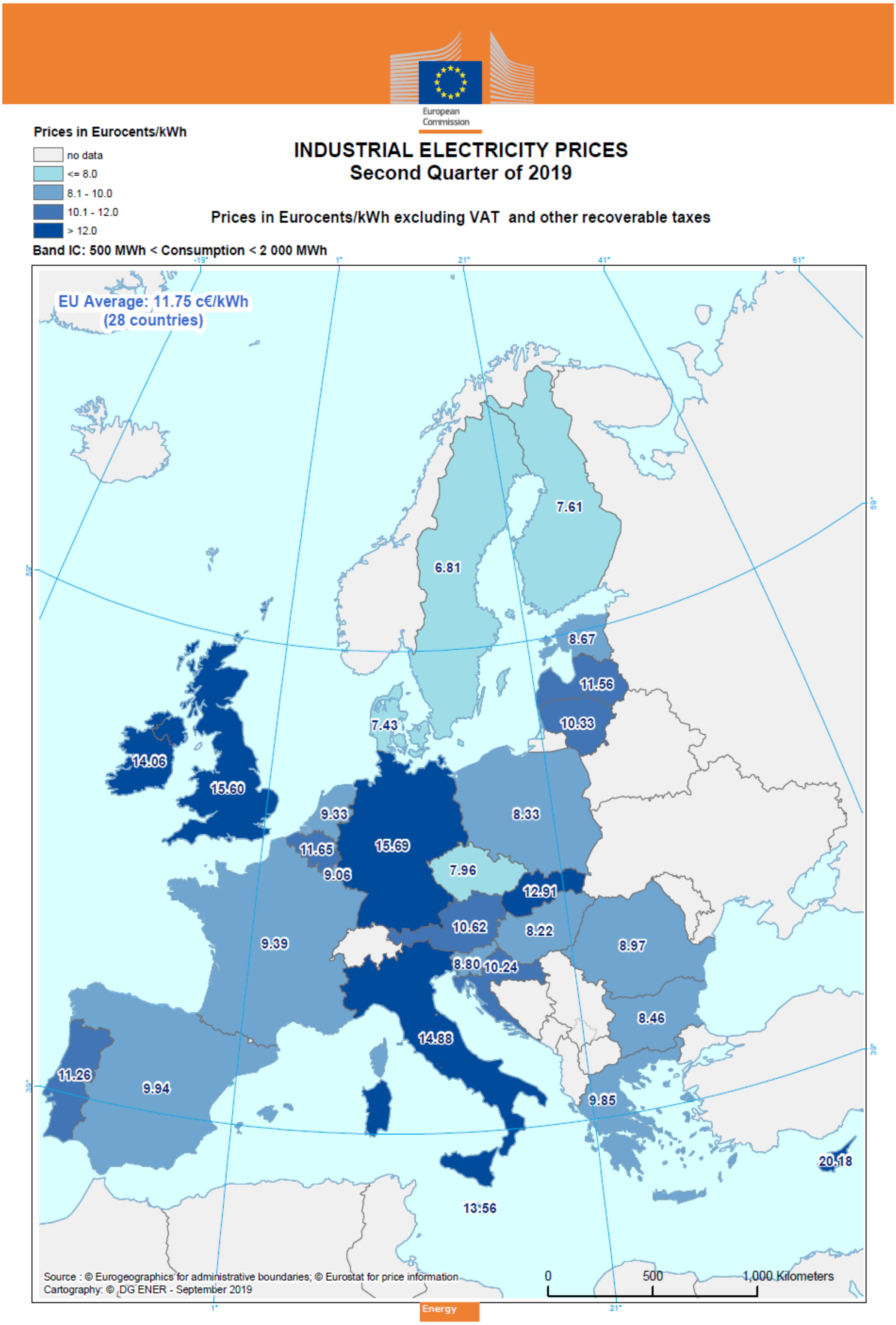
- **Figures 43 and 44** display estimated electricity prices paid by households and industrial customers in the EU, with medium level of annual electricity consumption in the last month of Q2 2019. In the case of household prices, Germany replaced Belgium at the top of the list, with Denmark occupying the third place. As in previous quarters, Bulgaria retained its position as the country with the cheapest household electricity prices. The average price in the EU stayed without significant changes compared to the situation in Q1 2019 and rose by 4.8% compared to Q2 2018. The largest year-on-year increases in the household category were assessed in Cyprus (+19%), the UK (+15%), Lithuania (+15%), and Finland (+14%). The biggest year-on-year falls were estimated for Greece (-8%), Denmark and Poland (both -7%).
- In the case of mid-sized industrial consumers, Finland reported the most competitive figure in Q2 2019, unchanged from the previous quarter, while Germany, the UK and Italy stood at the other end of the spectrum. The average retail price in the EU increased by 0.6% compared to Q1 2019 and by 2.6% compared to Q2 2018.
- The comparison of household and industrial consumers shows that the latter ones display a significantly lower retail price dispersion across the EU, which could be traced to the increased attention to cost competitiveness paid by the industry.

Figure 43– Household Electricity Prices, second quarter of 2019



Source : Data computed from Eurostat half-yearly retail electricity prices and consumer price indices

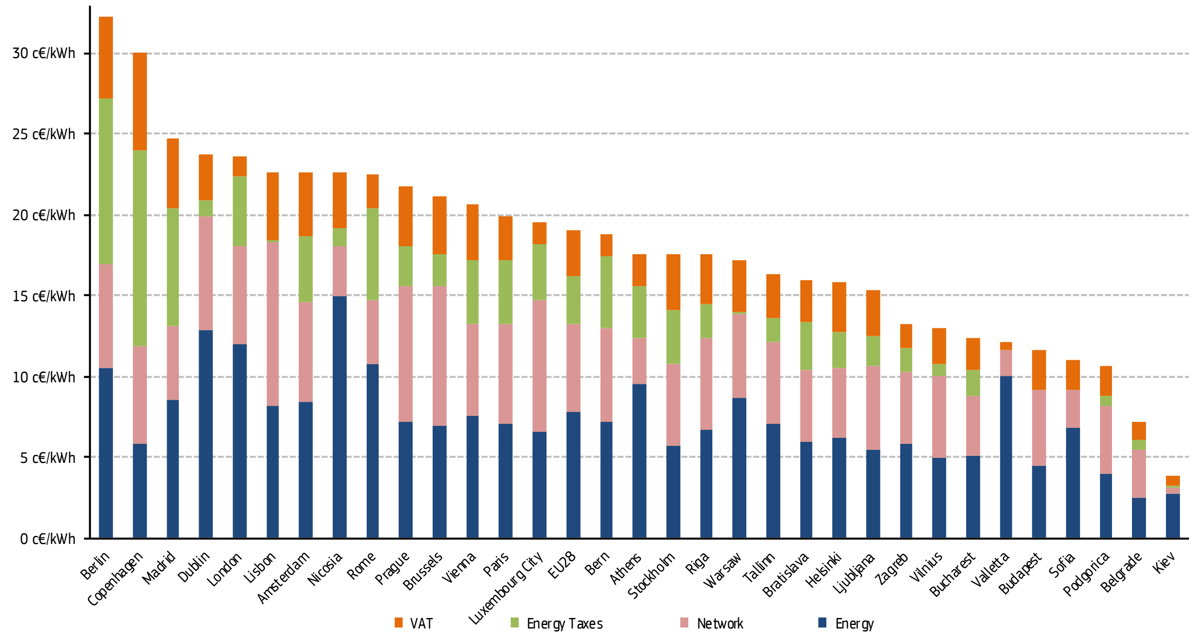
Figure 44 – Industrial Electricity Prices, second quarter of 2019



Source : Data computed from Eurostat half-yearly retail electricity prices and consumer price indices

- **Figure 45** shows retail electricity prices for representative household consumers in European capital cities and their composition divided into four categories (energy, network charges, energy taxes and the value added tax). In June 2019 the highest prices were observed in Berlin and Copenhagen (32.3 and 30.0 c€/kWh, respectively) where energy taxes accounted for approximately a third of the final bill. This corresponds to the Eurostat data analysed in **Figure 40**, apart from the position of Belgium. While on national average Belgium was the second most expensive country, Brussels was the eleventh most expensive member state capital with prices 29% lower than the rest of the country. The lowest prices of EU member states were recorded in Sofia and Budapest (11.1 c€/kWh and 11.7 c€/kWh, respectively). Non-member states in Europe's east tend to have the lowest prices. Thus, electricity for households in Kiev is generally eight times cheaper than in Berlin.
- The highest levels of the energy component were reported from Nicosia, Dublin and London (from 12-15 c€/kWh), cities surrounded by wholesale markets with relatively high prices compared to the EU average. The lowest levels of the energy component (4.5-6 c€/kWh) were recorded in capitals of countries with stronger forms of price regulation (Budapest, Bucharest, Bratislava) or with a high degree of renewable production (Copenhagen, Stockholm). The EU average in the reference quarter for the energy component was 7.9 c€/kWh.
- The highest network charges were recorded in Lisbon (10.17 c€/kWh) where, despite a significant cut compared to last year, they accounted for 45% of the total price and were measurably higher than the energy component. Relatively high network charges were also reported from Brussels, Prague and Luxembourg City (8-9 c€/kWh) where they accounted for around 40% of the total retail price. The lowest network fees were collected in Valletta (1.6 c€/kWh) and Sofia (2.4 c€/kWh). The EU average in the reference quarter was 5.4 c€/kWh.

Figure 45– The Household Energy Price Index (HEPI) in European capital cities in Eurocents per kWh June 2019

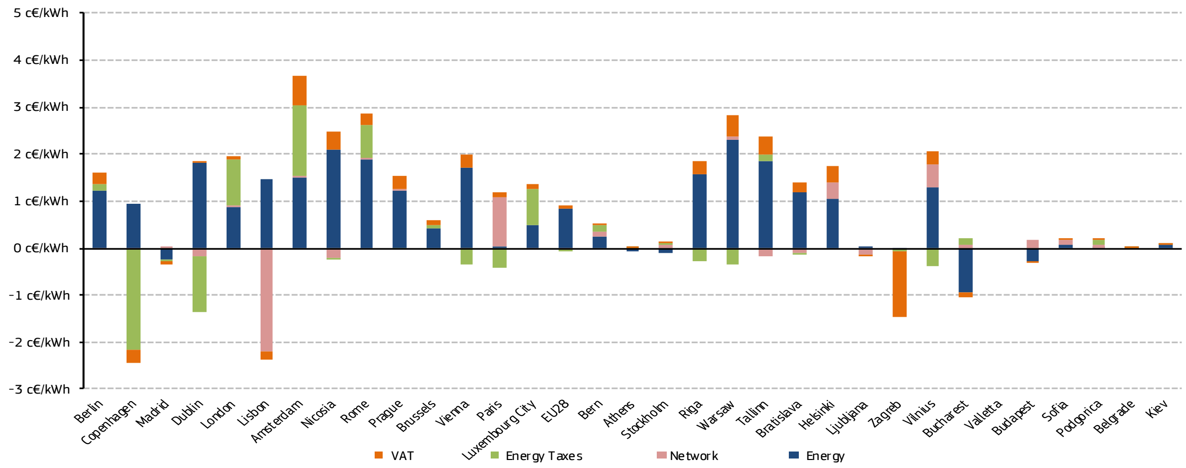


Source: Vaasaett

- Compared to the same month of the previous year, the largest price increases in June 2019 were observed in Amsterdam (+19%), followed by Warsaw (+17%) and Tallinn (+16%), as shown in **Figure 46**. In all three cities the energy component was the biggest contributor to rising prices, while in the case of the Dutch capital growing energy taxes and the VAT rate played their part too. Seven EU capitals reported prices lower than in the same month of the previous year, with Zagreb (-10%), Bucharest (-6%) and Copenhagen (-5%) posting the largest drops. The price fall in the Croatian capital was caused almost exclusively by a lowered VAT rate, whereas in the Romanian capital the decreasing energy component was the driving force. Retail prices in the Danish capital were pushed down by a substantial cut in energy taxes which compensated for an increase in the energy component.
- The energy component increased in all but six EU capitals from June 2018 to June 2019, with the highest rises registered in Warsaw, Nicosia, Rome, Tallinn and Dublin. Network charges remained broadly stable across the EU, with the exception of Portugal where a significant decrease drove the total retail price lower in spite of a more expensive energy component. Paris, on the other hand, experienced a substantial increase in network fees.

Measurable increases in network charges were also reported from Vilnius and Helsinki. Energy taxes decreased materially in Denmark and Ireland, while going up in the UK, the Netherlands, Luxembourg and Italy.

Figure 46 – Year-to-year change in electricity prices by cost components in the European capital cities comparing June 2019 with June 2018

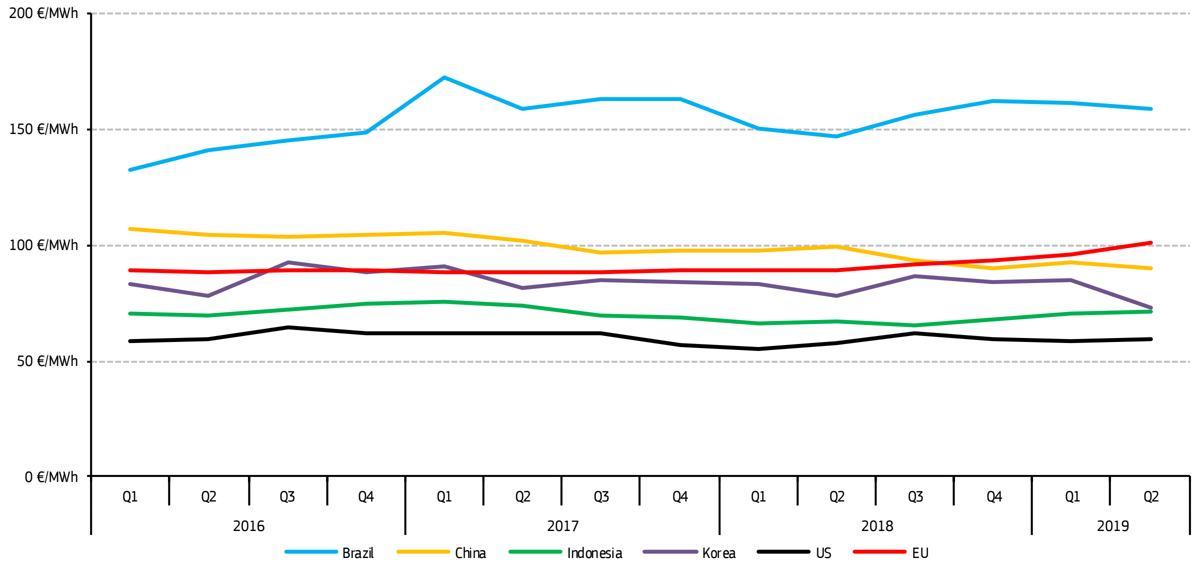


Source: Vaasaett

4.2 International comparison of retail electricity prices

- The following graph (**Figure 47**) displays industrial retail prices paid by consumers in the EU and in its major trading partners. Prices include VAT (with the exception of US prices) and other recoverable taxes for the purpose of comparability.
- Prices in the EU remained relatively high in Q2 2019, second only to prices in Brazil. Differences between wholesale electricity prices in the EU and the US are mirrored by differences between EU and US retail prices, with EU prices rising continually since 2017 and US prices on a mostly decreasing trajectory during the same period. The Chinese retail prices are also trending downwards. They fell under their EU peers in Q4 2018 and were 12% lower compared to the EU benchmark in Q2 2019.
- Retail prices for industry in Indonesia went up by 1% to 71.3 €/MWh in Q2 2019 compared to the previous quarter. Brazil, on the other hand, registered a 1% decline during the same period. South Korean retail industrial prices in Q2 2019 fell by 14% compared to Q2 2018, approaching their Indonesian peers.

Figure 47 – Retail electricity prices paid by industrial customers in the EU and its main trading partners



Source: Eurostat, IEA, CEIC, DG ENER computations

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.

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.

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.