European Commission

Quarterly Report on European Electricity Markets

with focus on energy storage and 2019 wholesale prices

Market Observatory for Energy

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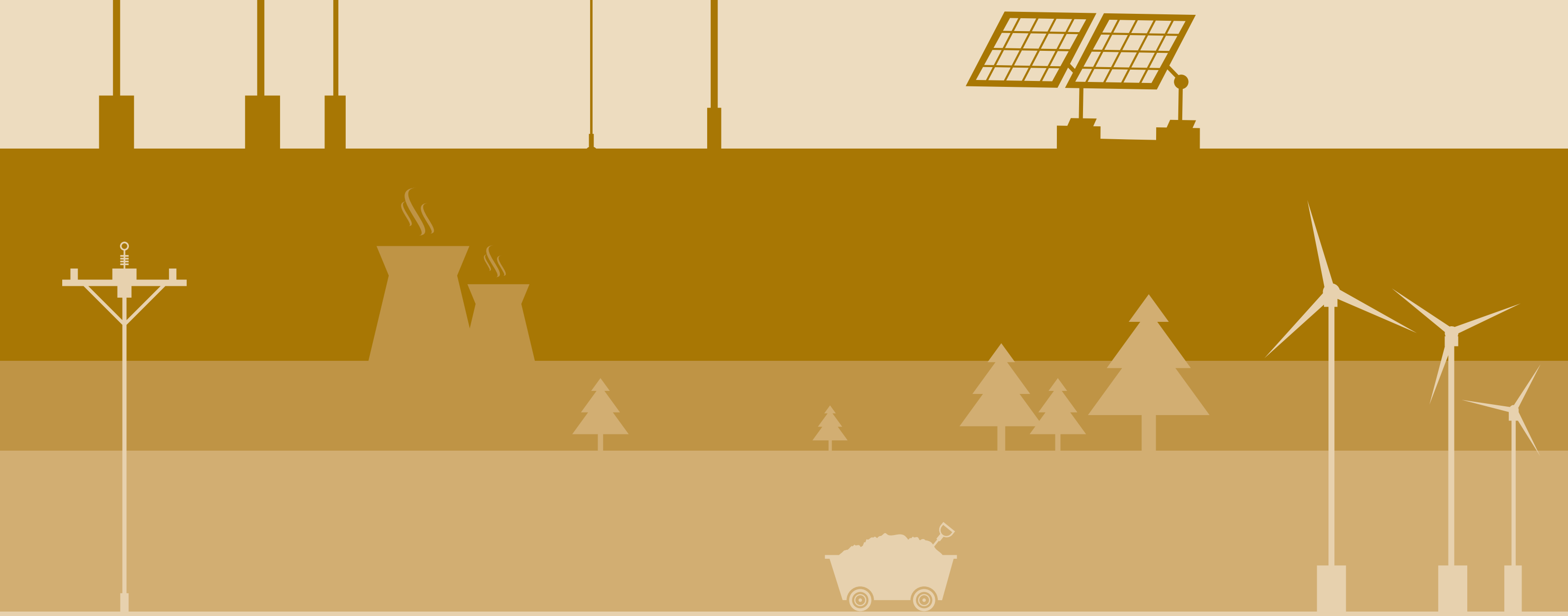

Energy

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CONTENT

HIGHLIGHTS OF THE REPORT

- **A decrease in carbon prices coupled with more expensive gas moderated the intensity of coal-to-gas switching in the final quarter of 2019 compared to the previous one. Nevertheless, coal-fired power plants remained under pressure and were being pushed out of market not only by gas but also by renewables and falling consumption. Relatively cheaper lignite capacities also continued to face headwinds due to their high carbon intensity.**

- **Electricity generation from solid fuels (coal plus lignite) in the EU28 fell by 26% year-on-year in Q4 2019 (or 39 TWh in absolute terms). Gas-fired power plants managed to replace only a relatively small part of the gap left by coal, increasing their output by 5% (or 9 TWh) year-on-year in the reference quarter. The rest was covered by growing renewables (+29 TWh), mainly wind farms and recovering hydro generation. Warm weather and slowing economic activity contributed to a measurable decrease in demand (-7 TWh). In December, the share of fossil fuels in the mix dropped under 35%, the lowest figure for that month on record.**

- **The share of renewable energy in the EU28 power mix reached 35% in the reference quarter, the highest for a fourth quarter yet and higher than the corresponding shares in China (27%), India (21%) and the United States (18%). The total combined output of solar, wind and biomass generation in the EU in the reference quarter increased by 8% year-on-year to 185 TWh. For the whole year 2019, the EU's electricity sector decreased its greenhouse gas emissions by approximately 12%, bringing a substantial contribution to Europe's decarbonisation efforts.**

- **The climb-down of carbon prices from summer record levels drove wholesale prices lower in most European markets in Q4 2019, with the biggest falls concentrated in the eastern part of the continent. France and several of its neighbours experienced rising baseload prices due to multiple maintenance overruns and unexpected outages of the French nuclear fleet. The pan-EU average price declined to 43.9 €/MWh, down 7% compared to the previous quarter.**

- **In 2019, just three markets (Bulgaria, Romania and Greece) saw significant annual increases in baseload prices, driven by more expensive emission allowances, relatively weak hydro output and higher electricity consumption. Belgium, Great Britain, the Netherlands and France, in contrast, saw baseload prices declining by more than a fifth year-on-year thanks to rising renewable penetration, falling gas prices, more interconnection capacity and falling consumption. With an annual average of less than 38 €/MWh, Germany had the lowest wholesale prices in Europe in 2019, beating the Nord Pool system price by more than 1 €/MWh. In France and Germany, hourly wholesale prices dropped under 30 €/MWh more than 20% of the time in 2019 and almost 45% of the time between 3am and 5am CET. The highest price volatility was observed in the integrated Irish market where the difference between the most expensive and the cheapest hour within one day was 54 €/MWh on average in 2019.**

- **Wholesale price convergence in Central Western Europe increased noticeably in 2019 compared to the previous year. This occurred despite the splitting of the DE-LU-AT bidding zone, which came into effect in October 2018 and which established a separate zone for Austria. A considerable increase in price convergence occurred also within the Baltic region, despite its greatly increased import dependence, and between Croatia and Slovenia.**

- **Although the energy component of household electricity prices fell in 10 EU28 capitals from December 2018 to December 2019, the general decrease in European wholesale prices witnessed during 2019 has not been fully passed through to the retail market yet. This could be explained by the fact that retailers usually buy electricity in advance before it is sold to customers, which results in a time lag between developments in the wholesale and retail markets. This also presents an opportunity for retailers with more dynamic pricing offers. During the course of 2019, the average assessed EU28 retail price for energy-intensive industry rose by 7% to 8.4 c€/kWh.**

- **Roughly 3% of new passenger cars sold in the EU28 in 2019 were electrically chargeable, compared to a 2% share in 2018. The number of public charging points tends to be relatively lower in countries with lower electric car sales. The expected expansion of battery demand from electric vehicles, consumer electronics and stationary energy storage systems is triggering a massive investment wave in Europe. By 2024, its battery cell manufacturing base is expected to expand from 17 GWh/year currently to more than 200 GWh/year, enough to power around four million cars.**

EXECUTIVE SUMMARY

- Electricity consumption in the EU28 declined by approximately 1% year-on-year in Q4 2019, dragged down by stagnating industrial activity and a very mild start of the heating season. Of the major economies, power consumption increased in the UK (+1.2%) and the Netherlands (+1.3%), while falls were registered in Germany (-2.0%), Poland (-2.0%), Italy (-1.7%), Spain (-0.8%) and France (-0.8%). For the whole year 2019, electricity consumption in the EU28 declined by 1% compared to 2018, with all larger Member State's economies posting decreases amid slowing growth, warmer temperatures and persistent efficiency gains. The stagnating trend of the past ten years thus continued.

- Spot gas prices rebounded from summer multiyear lows and on average reached 12.6 €/MWh in Q4 2019 (up 23% compared to Q3 2019, but down 49% compared to Q4 2018) amid sufficient pipeline deliveries, plentiful LNG supply and high storage levels. Coal prices around the globe continued to be weighed down by China's weak import appetite. The average quarterly CIF ARA spot price was assessed at 50.0 €/t in Q4 2019 (down 2% compared to Q3 2019 and down 38% compared to Q4 2018).

- The carbon market experienced increased volatility in the first weeks of Q4 2019 due to uncertainties around evolving Brexit negotiations, before embarking on an upward trajectory from the middle of November and finishing the year at 26 €/t. The average quarterly CO2 spot price in the reference period went down by 8% compared to Q3 2019, a first such decline since Q2 2017. Nevertheless, at 25 €/t, the average price of one allowance in Q4 2019 was still 22% higher compared to the same quarter a year ago. For the whole year 2019, the carbon price went up by 57% year-on-year to 25 €/t.

- In Q4 2019, the estimated EU import bill for thermal coal amounted to €1.5 billion, 50% lower compared to Q4 2018. For the whole 2019, total coal imports fell by 26% and the import bill decreased by a third compared to 2018 to €7 billion. The significant fall in coal imports reflected continually adverse conditions for coal-fired generation.

- The structure of the generation in the reference quarter was influenced mainly by recovering hydro production and a decline in coal and lignite generation, which was pressured by cheaper-to-run renewable sources and gas power plants. Compared to the same quarter of the previous year, the share of fossil fuels (solid fuels, gas, oil) in Q4 2019 decreased from 42% to 39%, while the share of renewables rose from 31% to 35% on the back of record hydro and wind production growth. The share of nuclear generation remained broadly stable at 25%.

- The main drivers behind the increased share of renewable power in the reference quarter were high hydro output (up 16 TWh year-on-year), which recovered from low summer levels, and rapidly rising wind generation, which in its onshore segment expanded by 9% year-on-year (or 9.0 TWh) and in the offshore sector recorded a 18% year-on-year increase in generation (or 3.3 TWh). Strong wind currents in December and record high hydro generation lifted the combined output from renewables to 105 TWh, a new monthly maximum.

- The rise in carbon-free generation was greatly helped by over 30 GW of renewable capacity installed in 2019, most of it in solar PV (17 GW) and wind farms (13 GW). The largest additions were registered in Spain (7.3 GW) and Germany (6.2 GW). Hundreds of MW of the new capacity were installed as subsidy-free, underlining the fact that in a growing number of countries, renewable sources have reached maturity and can compete with other generation assets on market terms.

- The European Power Benchmark of seven major markets averaged 39.9 €/MWh in the reference quarter, up 2% compared to the previous quarter. The cheapest baseload power prices were observed in the Nordic and CWE regions, which benefit from high shares of nuclear or/and renewable sources. Markets in the eastern and southern parts of the continent (Poland, Hungary, Romania, Bulgaria, Greece, Italy), with a relatively high share of carbon-intensive generation or with greater reliance on imports, found themselves on the other side of the price spectrum.

- Average retail electricity prices for households with mid-sized consumption in the EU rose by 1% year-on-year in the reference quarter. The largest year-on-year increases in the household category were assessed in Czechia (+17%), followed by the Netherlands and Lithuania (both +14%). The biggest year-on-year falls were estimated for Spain (-18%) and Estonia (-16%). In the case of mid-sized industrial consumers, Sweden was assessed to have the most competitive price in Q4 2019, moving in front of Denmark and with Finland taking the third place.

- The withdrawal agreement between the United Kingdom and the EU entered into force on 1 February 2020. The current report, covering the fourth quarter of 2019, still includes the United Kingdom in the EU aggregates, if not indicated otherwise. The next report, covering Q1 2020, will treat the UK numbers separately from the EU aggregates.

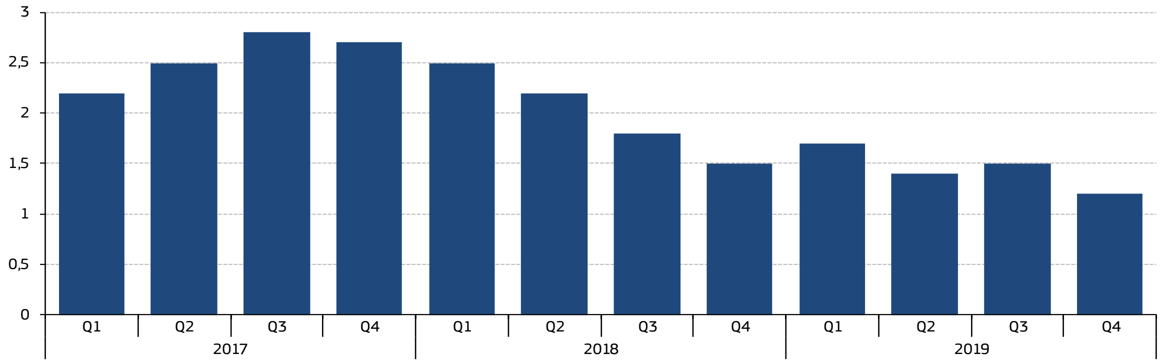
1 Electricity market fundamentals

1.1 Demand side factors

- **Figure 1** shows that the pace of economic growth in the EU28 slowed down in Q4 2019 compared to the previous quarter, prolonging a decelerating trend visible since 2017. According to an estimate published by Eurostat, seasonally adjusted GDP in the EU28 expanded by 1.2% year-on-year between October and December 2019, which compares to 1.5% achieved in Q4 2018.

- According to the estimates by Member States' statistical services, regulatory authorities and TSOs, the consumption of electricity in the EU28 fell by 1% year-on-year in Q4 2019, amid declines in most Member States. Of the major economies, power demand increased in the Netherlands (+1.3%) and the UK (+0.6%), while falls were registered in Germany (-2.0%), Poland (-2.0%), Italy (-1.7%), Spain (-0.8%) and France (-0.8%). The largest increase was recorded in Ireland (+3.0%), which posted the strongest growth figure among Member States and also experienced colder-than-usual weather in the reference quarter. Stagnating industrial activity and a very mild start of the heating season dragged down EU-wide consumption levels in Q4 2019. For the whole year 2019, electricity consumption in the EU28 declined by 1% compared to 2018, with all major economies posting decreases amid slowing growth, warmer winter months and persistent efficiency gains. The stagnating trend of the past ten years thus continued.

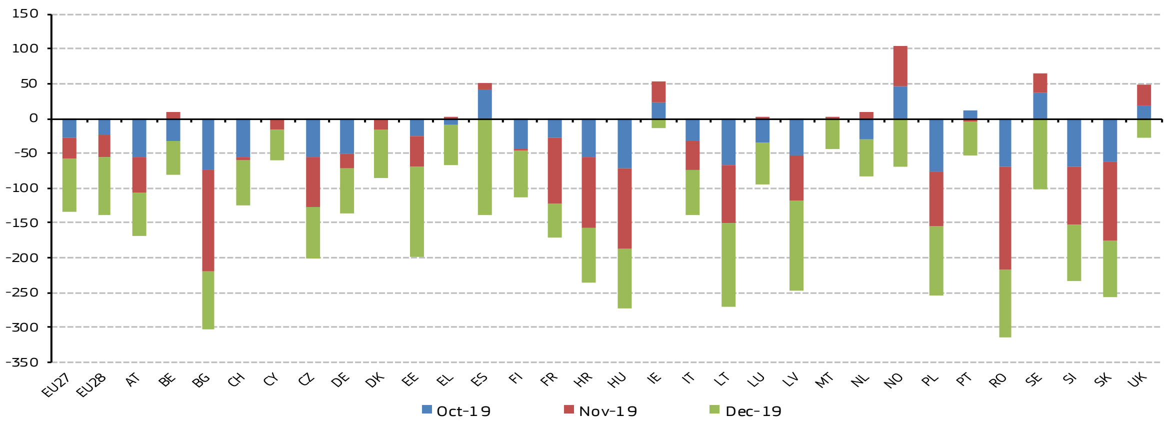
Figure 1 – EU28 GDP annual change (%)



Source: Eurostat

- **Figure 2** illustrates the monthly deviation of actual Heating Degree Days (HDDs) from the long-term average in Q4 2019. EU28-wide, the quarter had 139 HDDs below average (which translates to 1.5 °C higher temperature than usual per day). Relatively mild weather was observed in all three months of the reference quarter, with December being exceptionally warm. According to the Commission's climate change monitoring agency, the last month of 2019 was the hottest December in Europe on record. Higher-than-usual temperatures were measured in the vast majority of Member States, with the highest deviations observed in the eastern part of the continent. Romania, Bulgaria, Hungary, Lithuania, Slovakia and Poland had more than 250 HDDs below the normal, which means that every day was on average nearly 3 °C warmer than usual in those Member States. This resulted in lower heating-related demand. Only the British Isles became an exception, witnessing relatively colder weather in October and November, followed by an average start of the winter season.

Figure 2 - Deviation of actual heating degree days from the long-term average in October-December 2019

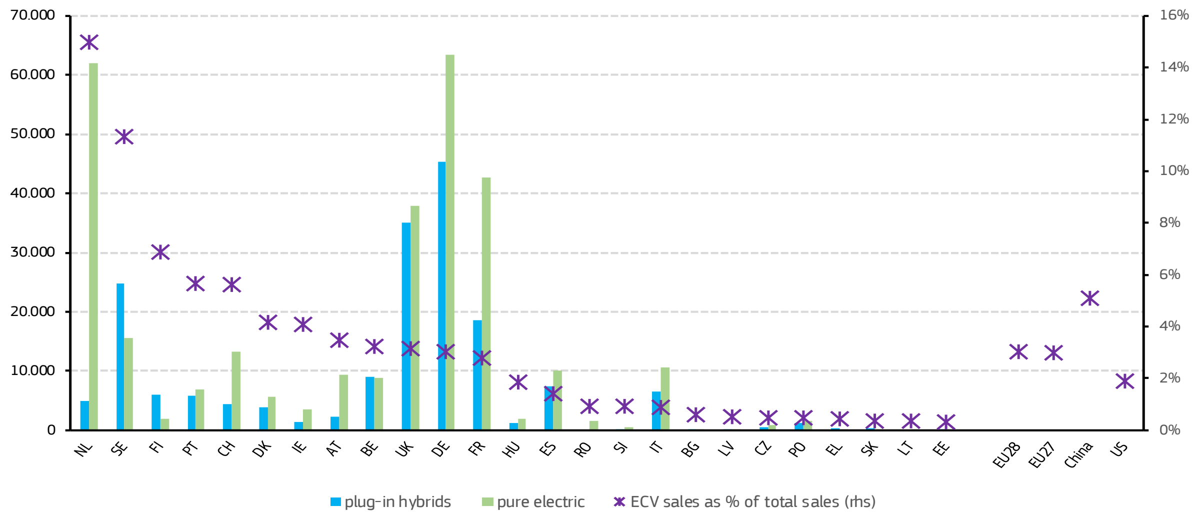


Source: JRC. The colder the weather, the higher the number of HDDs.

- **Figure 3** illustrates the demand for electrically chargeable vehicles (ECVs) in European countries. In 2019, the total EU28 sales reached nearly 459,000 ECVs (174,000 plug-ins and 285,000 pure electric vehicles), up by 53% compared to 2018. Thus, 3% of new passenger cars sold in the EU (both EU27 and EU28) in 2019 were electrically chargeable, compared to a 2% share in 2018. The highest ECV penetration was observed in the Netherlands where one in seven new passenger cars sold could be plugged. Sweden came in second with an 11% ECV share, followed by Finland, Portugal, Switzerland, Denmark and Ireland. The UK, Germany and France, the three biggest European car markets, posted shares in line with the EU average, whereas Spain and Italy, number four and five in terms of total annual car sales, lagged behind. In 11 Member States, the share of purchased ECVs in the market did not exceed 1%. The respective figure for Norway was 56% in 2019. Overall, ECVs on European roads are not yet represented in numbers sufficient to materially influence electricity demand, consuming less than 0.1% of net generation in 2019 according to DG ENER estimates.

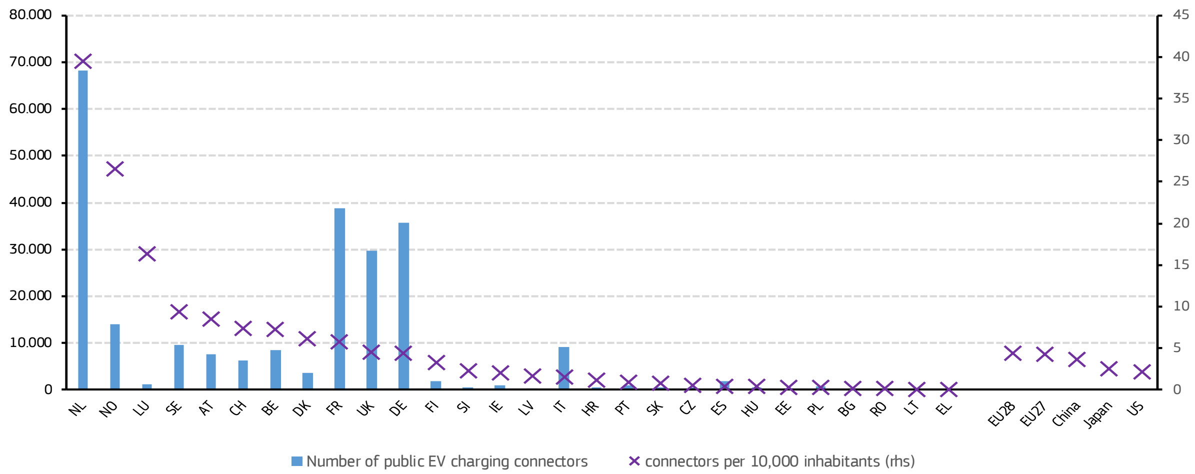
- **Figure 4** looks at charging infrastructure for ECVs in individual European countries by comparing the most recent numbers of connectors in absolute terms and in relation to population figures. The Netherlands tops the table again with nearly 40 connectors per 10 thousand inhabitants, followed by Norway (27), Luxembourg (16) and Sweden (9). 11 Member States have less than one connector per 10,000 inhabitants. Approximately 11% of all the installed connectors are of the fast or ultra-fast category (more than 43kW, capable of recharging a vehicle in dozens of minutes). The comparison between Figures 3 and 4 shows that the number of charging points tends to be relatively lower in countries with lower ECV penetration. Finland is a notable exception, having a relatively small public charging base set against annual ECV sales. The large majority of Member States offer incentives for purchasing ECVs, mostly in the form of tax reductions. Around half of Member States offer bonus payments or premiums.

Figure 3 – Electrically chargeable vehicle (ECV) sales in Europe and worldwide in 2019



Source: ACEA, CAAM, MarkLines

Figure 4 – Public charging connectors for ECVs in European countries and worldwide

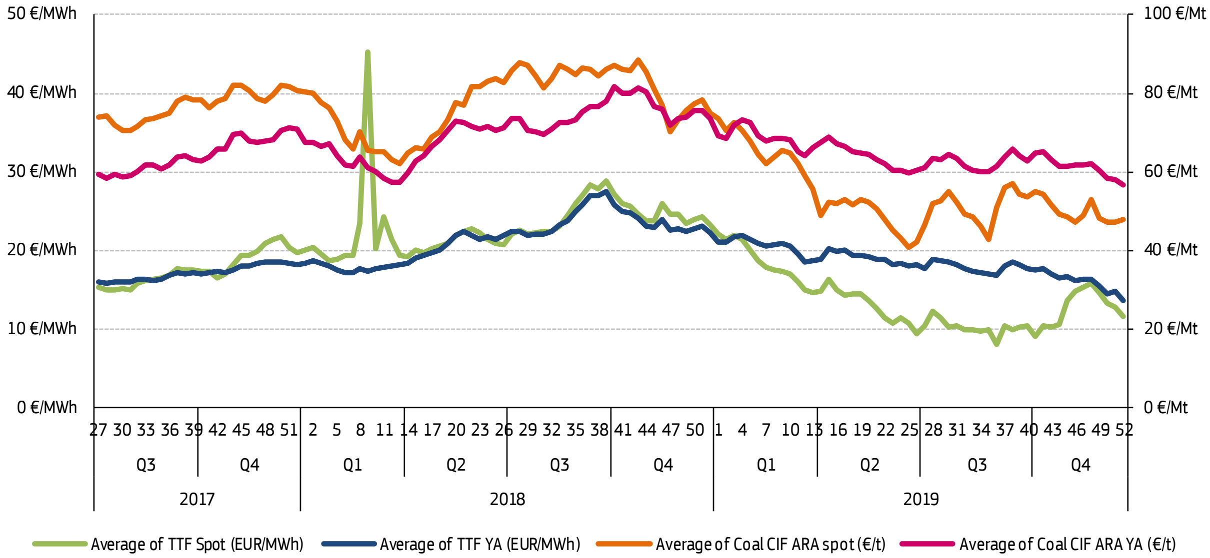


Source: BloombergNEF. Data as of 31 January 2020. There can be multiple connectors per charge point.

1.2 Supply side factors

- **Figure 5** reports on the developments in European coal and gas prices. Spot prices of either commodity followed different paths. Gas contracts were sharply lifted from 10-year lows but could not keep much of their gains in the end. Their coal peers followed a decreasing trend most of the time. Meanwhile, year-ahead prices for both commodities moved more or less in tandem and remained in their contango position vis-à-vis the spot market, which they entered at the start of 2019.
- Spot gas prices (represented by the TTF day-ahead contract) experienced volatile trading in October with prices moving between 8 and 12 €/MWh on the back of shifting weather forecasts for the start of the heating season and unusually high storage levels that left little room to manoeuvre for balancing during periods of weak demand. A strong rally followed in November as demand finally picked up and storage facilities switched from injection to withdrawal. Spot contracts surged above 15 €/MWh in weeks 47-48, but the rally gradually dissipated in December, thanks to very warm weather conditions that dampened heating demand and high wind generation that restricted gas burn for electricity production. The market remained well supplied during the entire reference period thanks to plentiful LNG deliveries and record high storage levels. Overall, the average quarterly TTF spot price reached 12.6 €/MWh in Q4 2019 (up 23% compared to Q3 2019, but down 49% compared to Q4 2018).[1]
- Thermal coal spot prices, represented by the CIF ARA contract, were following a declining trajectory in the reference quarter amid high stockpiles at main terminals and low demand caused by continued coal-to-gas switching and warm weather. Coal prices around the globe continued to be weighed down by China's weak import appetite. The average quarterly CIF ARA spot price was assessed at 50.0 €/t in Q4 2019 (down 2% compared to Q3 2019, and down 38% compared to Q4 2018).
- Year-ahead gas prices continued in their slide in Q4 2019 and, at 16.2 €/MWh, were trading on average 10% lower than in the previous quarter, moving closer to spot quotes. Meanwhile, year-ahead CIF ARA contracts followed gas on the forward curve, falling significantly under 60 €/t for the first time in 20 months and keeping clean dark spreads for the next year competitive vis-à-vis their spark peers.

Figure 5 – Weekly evolution of spot and year-ahead coal and gas prices



Source: S&P Global Platts

- The market for emission allowances, shown in **Figure 6,** experienced increased volatility in the first half of Q4 2019 on the back of evolving Brexit negotiations, before embarking on an upward trajectory from the middle of November and finishing the year at 26 €/t, about 1 €/t above the level where it started in 2019.

[1] For more information on gas markets see Quarterly Report on the European Gas Markets, Vol. 13, Issue 4.

- CO_2 prices went sharply down in the first two weeks of the reference quarter, as the Brexit deadline applicable at that time (October 31st) was approaching and the absence of the withdrawal agreement put into question UK's participation in the EU ETS and, by extension, the short term outlook for supply-demand equilibrium in the market. The influence of Brexit negotiations was visible through a high correlation between the price of allowances and the GBP/EUR exchange rate. After bottoming out at a six-month low of 22 €/t, CO_2 prices quickly rebounded towards 26 €/t as prospects for a negotiated settlement improved and an additional extension of the deadline was granted. A further increase, however, was stopped by a general weakness in demand stemming from the coal-to-gas switch in power generation. Low gas prices kept gas-fired power plants, which emit less CO_2 per MWh produced, busy at the expense of their coal-fired competitors. This contributed to a decrease in carbon prices during the first half of November, and was compounded by uncertainties surrounding the fate of allowances not demanded by coal plants subject to negotiated closures in Germany. A turnaround came in the middle of November on the back rising fuel prices and expectations of increased demand for thermal generation in the upcoming winter season. The rising trend continued in December as the market digested the announcement of the European Green Deal, results of the British general election and delays of sales of allowances for the EU's Innovation Fund.
- All in all, the average quarterly CO_2 spot price in the reference period went down by 8% compared to Q3 2019, a first such decline since 2017. Nevertheless, at 25 €/t, the average price of one allowance in Q4 2019 was still 22% higher compared to the same quarter a year ago. For the whole year 2019, the CO_2 price went up by 57% year-on-year to 25 €/t.
- In Q4 2019, as in the previous three quarters, both the free allocation and auctioning of emissions allowances by the UK government were suspended.

Figure 6 – Evolution of emission allowance spot prices from Q1 2018

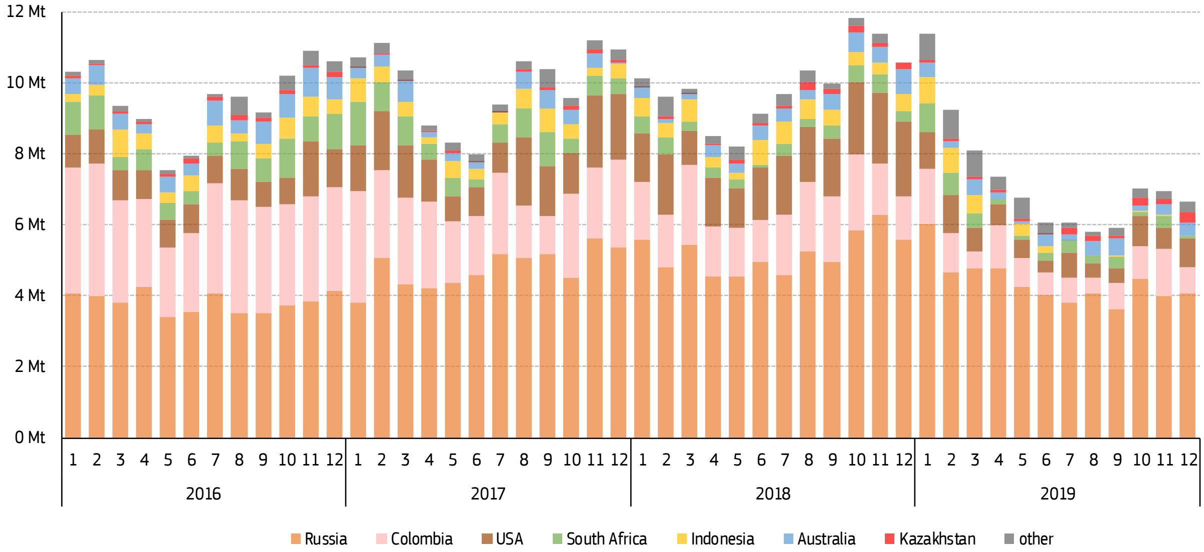
Source: S&P Global Platts

- **Figure 7** reports on monthly amounts of thermal coal imports into the EU28. Provisional Eurostat data show that in the fourth quarter of 2019 thermal coal imports reached 20.6 Mt, down 38% compared to the previous Q4. This reflects the sharp fall of coal use in electricity generation in Europe (see **Figure 11**) and the adverse conditions for coal-fired generation in the quarter (see **Figure 16**). The estimated EU28 import bill for thermal coal amounted to €1.5 billion, 50% lower compared to Q4 2018, exceeding the year-on-year decline in imported volumes due to lower prices of the commodity. For the whole 2019, the the thermal coal import bill decreased by a third compared to 2018 to €7 billion.
- The largest part of extra-EU thermal coal imports in the reference quarter came from Russia, accounting for nearly 61% of the total. Russia continued to hold a strong position in the European thermal coal market, but its share slipped by a few percentage points compared to Q3 2019 as exporters from other countries (the United States, Colombia, and Kazakhstan) gained ground. Colombia retained the position of the second most important import source, increasing its share from 11% in Q3 2019 to 15% in Q4 2019. The United States was the third most important thermal coal trading partner, providing 11% of all imports (up from 9% in Q3 2019). Australia and Kazakhstan each accounted for 4% of EU's thermal coal imports in the reference period, trailed by South Africa (2.7%).
- In 2019, Russian suppliers delivered 53 Mt of the 87 Mt of total thermal coal imports, capturing 60% of the market and again increasing their share compared to 2018 (when it reached 53%). The Russian gains came 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 had another record year with 437 Mt mined in 2019) and also partly by deliberate efforts of Russian exporters to expand their presence in the European market.

- The year-on-year decline in thermal coal shipments in Q4 2019 could be observed in all major EU importers. Deliveries to German, Belgian and Dutch terminals (calculated together as part of one supply chain feeding German and Dutch power plants) fell by 34% year-on-year to 9.6 Mt amid slow restocking activity ahead of the winter season. Polish terminals saw one the smallest decreases in deliveries in Q4 2019 (-9% year-on-year to 3.4 Mt), as imports continued to substitute domestic production. In the rest of the major markets, coal-to-gas switching significantly reduced coal deliveries, with Italy registering 2.1 Mt of imports (-26% year-on-year), France 1.2 Mt (-49% year-on-year) and Spain 1.0 Mt (-72% year-on-year).

Figure 7 – Extra-EU thermal coal import sources and monthly imported quantities in the EU28



Source: Eurostat.

2 European wholesale markets

2.1 European wholesale electricity markets and their international comparison

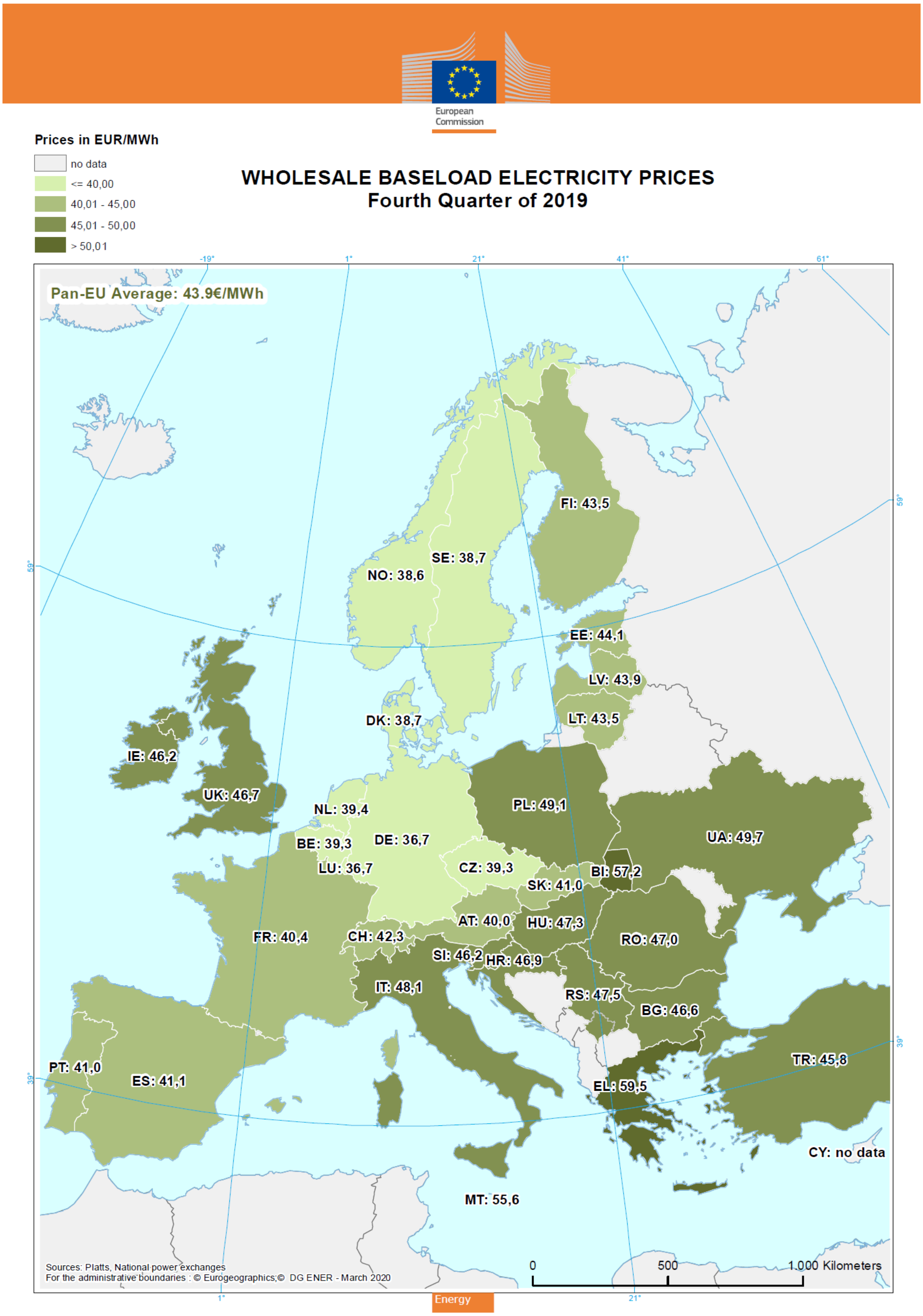
- The map on the next page shows average day-ahead wholesale electricity prices across Europe in Q4 2019. The cheapest baseload power prices were observed in the Nordic and CWE regions, which benefit from high shares of nuclear or/and renewable sources. Markets in the eastern and southern parts of the continent (Poland, Hungary, Romania, Greece, Italy), with a relatively high share of carbon-intensive generation or with greater reliance on imports, found themselves on the other side of the price spectrum.

- The highest average prices in Q4 2019 were registered in Greece (60 €/MWh) and Malta (56 €/MWh), followed by Poland (49 €/MWh), Italy (48 €/MWh), Hungary and Romania (both 47 €/MWh). Some of these countries traditionally rely on imports of electricity (Greece, Hungary), some have limited cross-border transmission capacities (Malta, Greece), and some faced increased production costs in the reference quarter due to high CO_2 prices penalizing their carbon-intensive generation mix (Poland, Greece). Romania suffered from low hydro and coal generation and had to resort to increasing imports. The lowest quarterly wholesale prices were recorded in Germany (37 €/MWh), where renewable penetration reached new highs, in Norway and Sweden (39 €/MWh), where ample hydro reservoir levels and rising wind generation kept baseload contracts low, and in Denmark (39 €/MWh), where wind farms covered around half of power demand.

- The pan-EU average of wholesale baseload prices reached 44 €/MWh in the reference quarter, down 29% in a year-on-year comparison. Compared to Q3 2019, the wholesale benchmark fell by 6% on the back of lower carbon prices, weak demand and increased wind generation.

- In an annual comparison, all markets saw prices coming down from record high levels in Q4 2018. The biggest decreases happened in Belgium (-45%), Ireland, France (both -36%), the Netherlands, Portugal and Spain (all -35%).

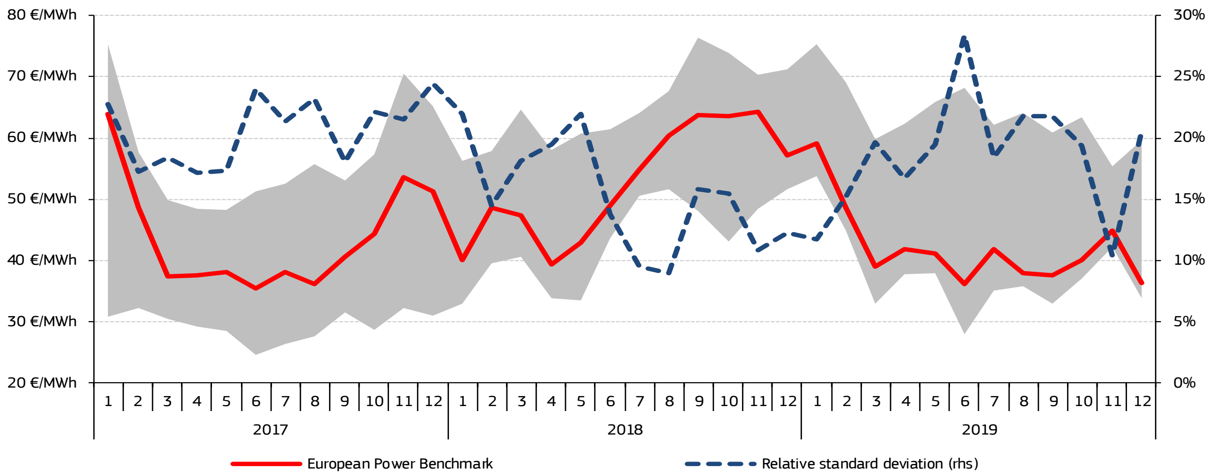
Figure 8 – Comparison of average wholesale baseload electricity prices, fourth quarter of 2019



Source: European wholesale power exchanges, government agencies and intermediaries

- **Figure 9** 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 convergence of wholesale prices across different regional markets in Europe briefly increased in November, only to return to the level from the start of the quarter in December. This was due to the fact that average prices in countries and regions that traditionally form the lower part of the spectrum (Nord Pool, Germany, France) registered increases across the board in November, while markets that usually find themselves in the upper part of the range saw baseload prices decrease significantly (Greece, Spain, Italy). This rare confluence of developments, however, did not last long as the Greek baseload contract started rising again in December, whereas the rest of the markets under observation headed lower.

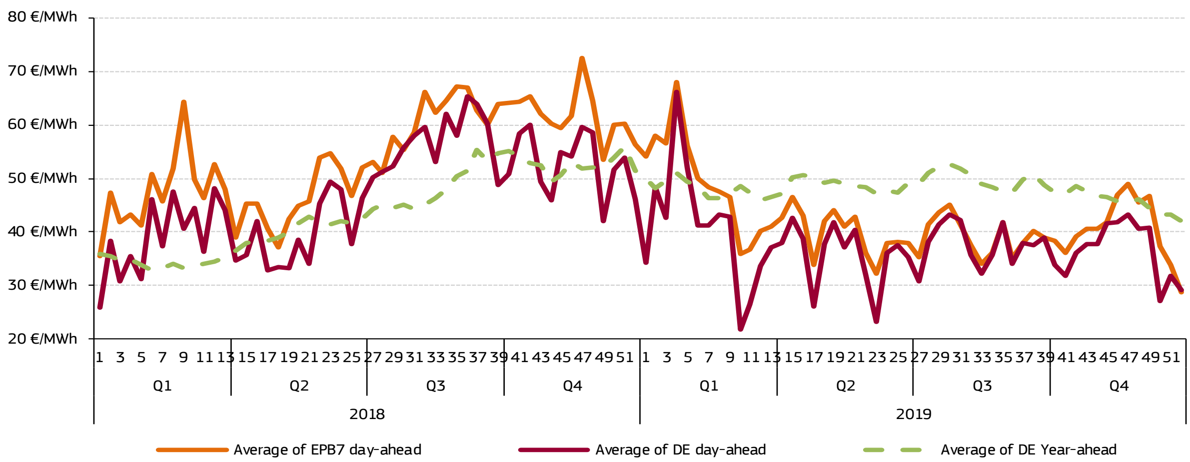
Figure 9 – The evolution of the lowest and the highest regional wholesale electricity prices in the EU day-ahead markets and the relative standard deviation of the regional prices



Source: Platts, European power exchanges. The shaded area delineates the spectrum of prices across EU regions.

- **Figure 10** shows the evolution of the European Power Benchmark (EPB) spot wholesale electricity price, as well as German day-ahead and year-ahead contracts for baseload delivery 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. In the first half of the reference period, both the EPB and day-ahead German contracts were propelled higher, first by a rebound in CO2 prices and then by rising gas prices. A greater distance between the German day-ahead price and the EPB benchmark is visible in the second half of November, when spot gas prices peaked, as gas has a larger influence over power prices in most EPB constituents. In the middle of December, both the EPB and German spot prices quickly sank amid mild weather, high wind output and falling gas prices, finishing the year close to 30 €/MWh. Meanwhile, year-ahead German prices were gradually pulled down by declining year-head coal and gas contracts, decreasing by 9% on average in Q4 2019 compared to Q3 2019 and finishing the reference quarter slightly under 45 €/MWh.

Figure 10 – Weekly evolution of day-ahead and year-ahead German electricity prices and the EPB



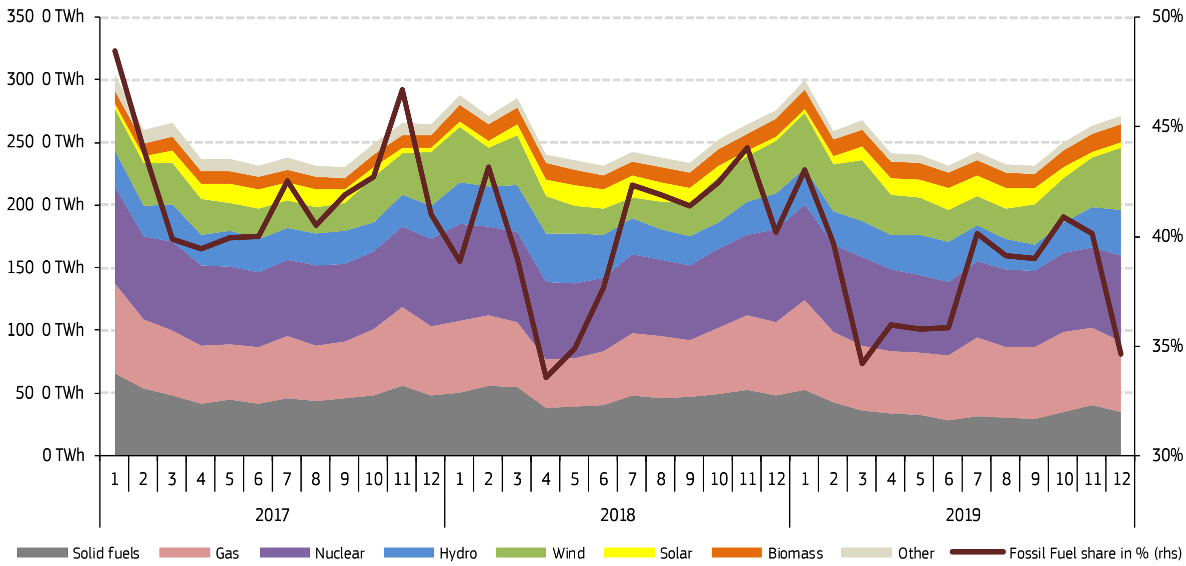
Source: S&P Global Platts and DG ENER, EPB7 is the replacement of the S&P Global Platts PEP since January 2017.

- **Figure 11** shows the evolution of the electricity mix in the EU28. The structure of the generation in the reference quarter was influenced mainly by recovering hydro production and a continued decline in coal and lignite generation, which was pressured by more competitive gas power plants and rising renewable generation. Compared to the same quarter of the previous year, the share of fossil fuels (solid fuels, gas, oil) in Q4 2019 decreased from 42% to 39%, while the share of renewables (hydro, biomass, wind and solar) rose from 31% to 35% on the back of record hydro and wind production growth. The share of nuclear generation remained broadly stable at 25% as good availability of the Belgian fleet and increased generation in the UK and Germany compensated for a poor performance of French nuclear reactors.

- Weak demand throughout the quarter and rising renewable generation continued to restrict the space for thermal power plants. Within the fossil fuels complex, the effect of high CO2 prices and associated coal-to-gas switching was still visible, although gas was able to replace only a fifth of the volumes lost by coal and lignite in a year-on-year comparison. Less CO2-intensive gas generation continued to gain at the expense of coal mainly in Spain (+3.5 TWh), the Netherlands (+2.5 TWh), Germany (+2 TWh) and France (+0.5 TWh) and reached a 23% share in the overall mix in Q4 2019 (compared to 22% in Q3 2018). In absolute terms, gas-fired power plants increased their output by 9 TWh year-on-year in the reference quarter. Solid fuels, on the other hand, saw their share reduced to 14% in the reference quarter (from 19% in Q3 2018). That in absolute terms translated into 39 TWh less electricity produced by burning coal and lignite than in Q4 2018. Renewables generated 27 TWh of electricity more in the reference quarter than in Q4 2018.

- Between hard coal and lignite (the distinction between them is not visible in **Figure 11**), the latter tends to be more resilient in the face of changing market environment, as lignite generation traditionally displays more competitive marginal costs per unit of energy produced. This stems mainly from the low price/production cost of the input fuel, which is usually mined in close proximity to power plants that use it. On the other hand, lignite generators have a bigger carbon footprint per MWh (by about 20%) than their coal peers, which penalises the former ones more when emission allowances become costlier. In Q4 2019, CO2 prices were on average lower than in the previous quarter, causing relatively smaller losses for lignite-fired power plants. As a result, lignite-based generation in Q4 2019 fell by 17% year-on-year (or 11 TWh), while coal-fired generation plunged by 34% year-on-year (or 28 TWh). Thus, the combined share of coal and lignite (14%) in the EU power mix in Q4 2019 fell below that of wind (16%).

Figure 11 – Monthly electricity generation mix in the EU28



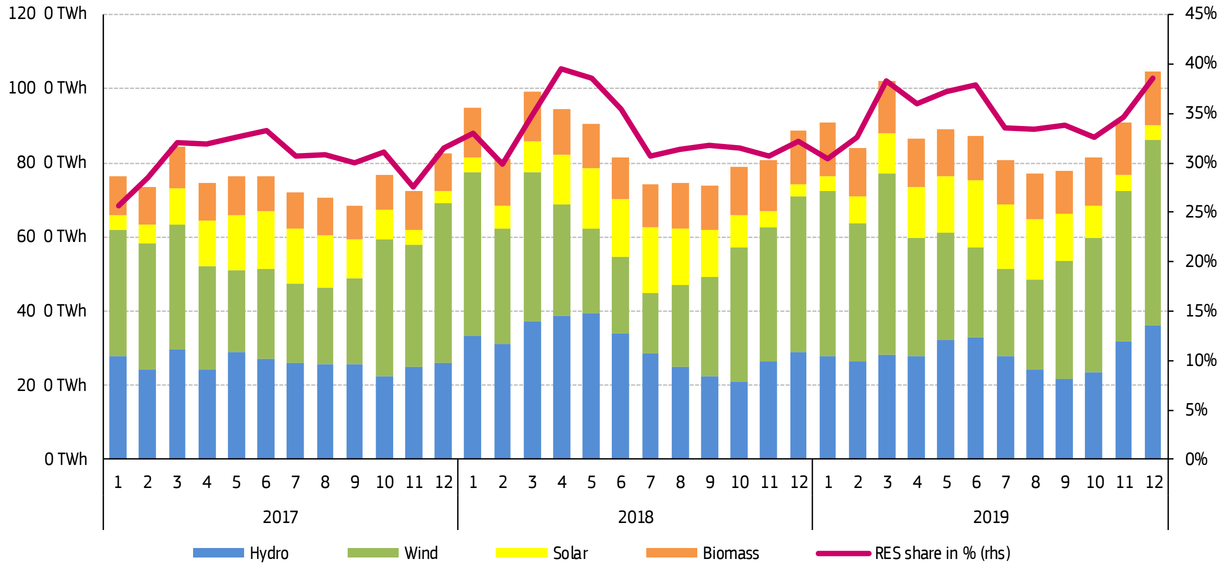
Source: ENTSO-E, Eurostat, DG ENER. Data represent net generation. Fossil fuel share calculation covers power generation from coal, lignite, gas and oil.

- **Figure 12** depicts the evolution of the monthly renewable generation in the EU28, alongside the share of renewables in the electricity generation mix. In Q4 2019, as in previous quarters of the year, renewable generation reached new records, accounting for 35% of the total net generation. That was more than three percentage points higher compared to Q4 2018. Strong winds in December and record high hydro generation helped push the combined output from renewables to 105 TWh, a new monthly maximum.

- The main drivers behind the increased share of renewable power in the reference quarter were high hydro output (up 16 TWh year-on-year), which recovered from low summer levels, and rapidly rising wind generation, which in its onshore segment expanded by 9% year-on-year (or 9.0 TWh) and in the offshore sector recorded a 18% year-on-year increase in generation (or 3.3 TWh). Solar-based generation in Q4 2019 grew by 4% (or 0.7 TWh) compared to Q4 2018. Biomass-based generation registered a 1% year-on-year rise in output.

- Wind-powered electricity generation recorded another impressive quarter in the final three months of 2019 and with a 16% share in the mix became the largest contributor to renewable output. The shares of solar and biomass remained largely unchanged in Q4 2019, compared to the same quarter of the previous year. The largest increases in wind output came from Germany, Spain, France and the UK. Italy, Belgium, Portugal and Poland also provided significant contributions in this respect. Onshore wind farms in France expanded their generation by 39% year-on-year (or 3.2 TWh) in the reference quarter.
- At 35%, the combined share of hydro, biomass, wind and solar in the EU electricity generation in Q4 2019 was higher than in other major economies. The share of renewables in the US power mix in the reference quarter stood at 18%, whereas in China and India renewable energy constituted 27% and 21% of their respective total power generation during the same quarter.[2]

Figure 12 – Monthly renewable generation in the EU28 and the share of renewables in the power mix

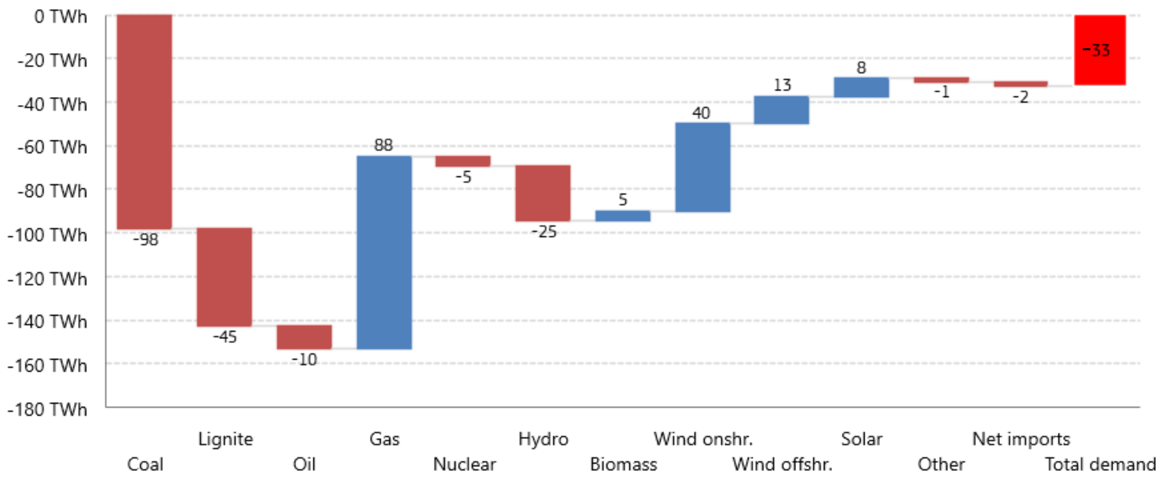


Source: ENTSO-E, Eurostat, DG ENER. Data represent net generation.

- **Figure 13** illustrates how the EU28 power mix changed between 2018 and 2019. Higher carbon prices combined with cheaper gas resulted in intensive coal-to-gas switching across the continent. However, gas was able to capture only about 60% of the volume lost by coal and lignite power plants. Rising renewable generation (+40 TWh) displaced a significant part of the fossil fuel-based generation, as did falling demand (-33 TWh). Wind-powered electricity (+53 TWh) was a major contributor to increased renewable output, making up for a substantial loss in hydro generation (-25 TWh). The annual decrease in power sector's CO2 emissions was estimated at 12% in 2019, mainly thanks to the coal-to-gas switch. Germany accounted for more than 40% of the decrease.

[2] Calculations based on the data from Energy Information Administration in the US, China Electricity Council and Central Electricity Authority in India. The Chinese figure does not contain burning of biomass.

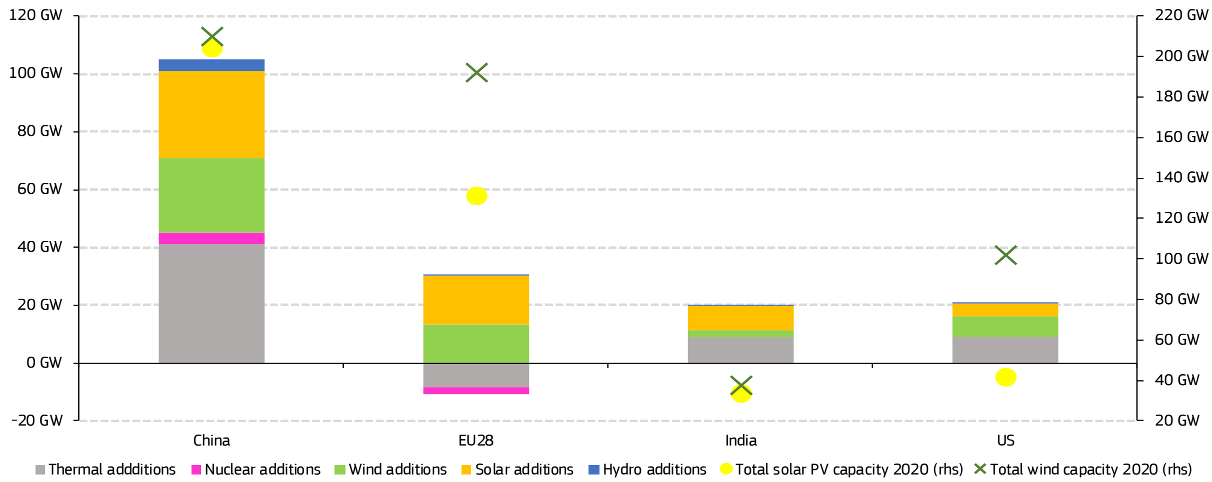
Figure 13 – Changes in the EU28 power mix between 2018 and 2019



Source: ENTSO-E, Eurostat. Data represent net generation. Red columns represent annual decreases while blue columns annual rises in generation.

- **Figure 14** on its left-hand scale maps newly installed power capacities on a net basis in the EU28 in 2019 and, for the sake of comparison, in other major economies. The European rise in carbon-free generation was greatly helped by over 30 GW of renewable additions. The largest additions were registered in Spain (7.3 GW) and Germany (6.2 GW). Hundreds of MW of the new capacity were installed as subsidy-free, underlining the fact that in a growing number of countries, renewable sources have reached maturity and can compete with other generation assets on market terms. Two nuclear reactors, in Sweden and Germany, were closed at the end of the year, removing 2.3 GW of nuclear capacity form the grid. Roughly 9 GW of coal- and lignite-fired capacity was retired on a net basis. This includes 1.8 GW of new coal units that started operation in Opole, Poland. Outside Europe, the largest renewable additions were registered in China (26 GW of wind, 30 GW of solar and 4 GW of hydro), which also put 41 GW of additional thermal capacities online in 2019.
- Total installed wind and solar PV capacities at the beginning of 2020, which are plotted on the right-hand scale of the chart, stood highest in China where they surpassed 200 GW in both categories. The EU28 approached this level in wind capacities, while having approximately 131 GW in solar PV installed at the start of 2020.

Figure 14 – Net capacity additions across major economies in 2019 and total installed wind and solar PV capacities at the beginning of 2020

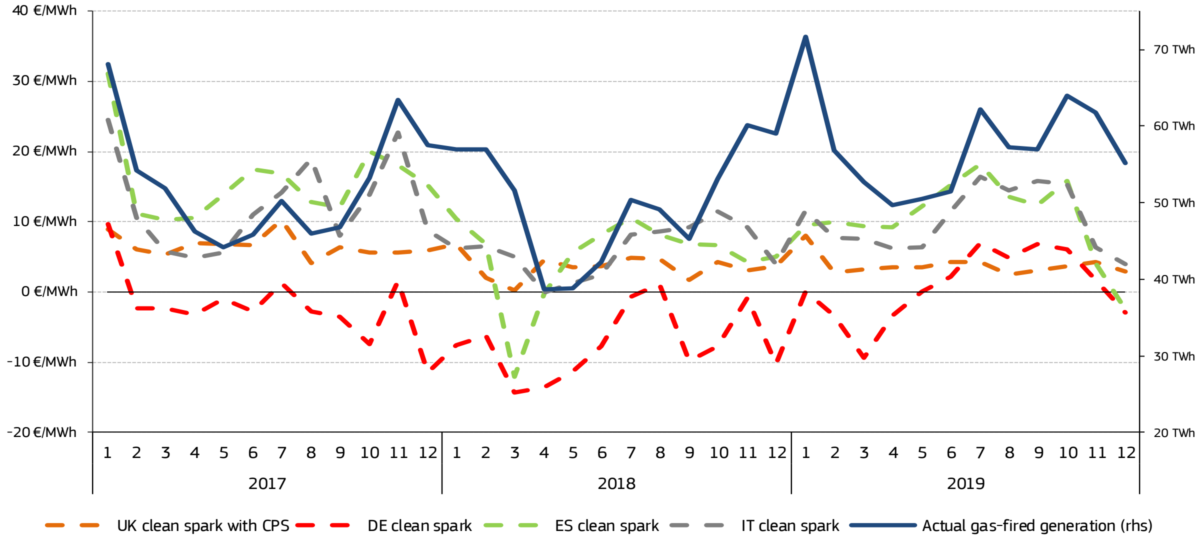


Source: China Electricity Council, Central Electricity Authority of India, FERC. For the EU28, ENTSO-E figures were used for thermal, nuclear and hydro additions; latest estimates from WindEurope and SolarPower Europe for wind and solar additions.

- **Figures 18 and 19** report on the profitability of gas-fired and coal-fired electricity generation in Germany, the UK, Spain and Italy by looking at the clean spread indicators on selected wholesale markets. On the whole, gas was still more competitive than coal in Q4 2019, but its margins gradually worsened on the back of higher gas prices in the second half of the quarter and falling power prices in December.

- As shown in **Figure 15,** the profitability of gas generation fell in each month of Q4 2019 in all countries under observation, except for the UK where it was stable. The biggest shift occurred in Spain where clean spark spreads went from positive double digits in October to negative territory in December. This was mainly due to a 28% decline in Spanish power prices during the reference period, the steepest of all four countries. Spanish gas generation volumes corresponded to the movement of spreads, falling from 8 TWh in October, to 6 TWh in November, and to 5 TWh in December. A similar scenario played out in Italy, with the difference that the fall in power prices in December was smaller, allowing clean spark spreads to stay above zero. Operators of gas-fired power plants faced increasing headwinds also in Germany, due to a rise in gas prices and a subsequent fall in power prices. Their British peers enjoyed a steadier price environment, which helped spreads stay without changes. The total EU28 gas generation reached 181 TWh in the reference quarter, compared to 172 TWh in Q4 2018.

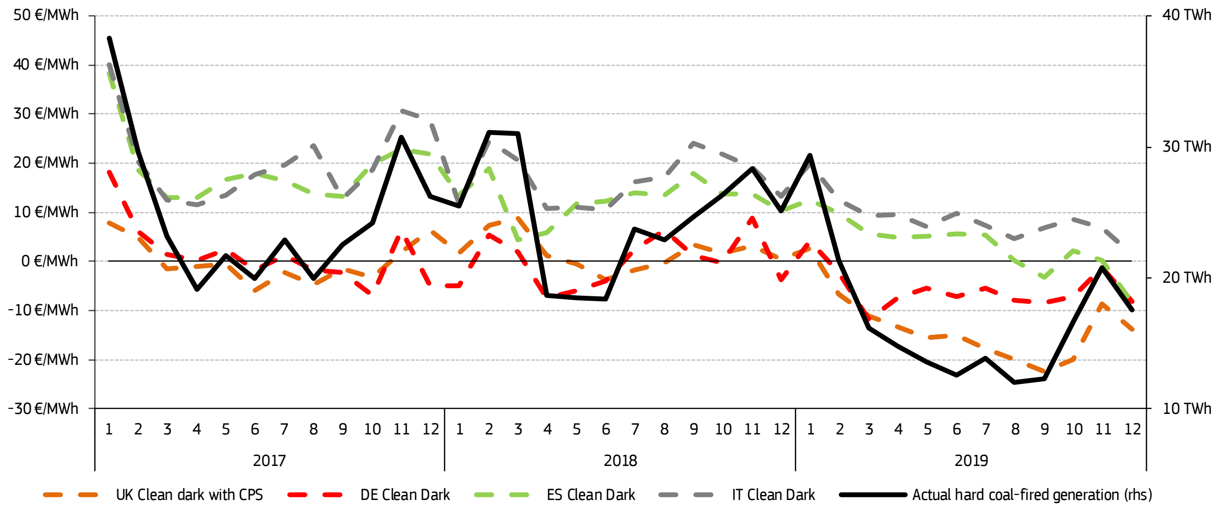
Figure 15 – Evolution of clean spark spreads in the UK, Spain, Italy and Germany, and electricity generation from natural gas in the EU28



Source: ENTSO-E, Eurostat, Bloomberg

- **Figure 16** demonstrates that coal generators across Europe were operating in mostly adverse environment in Q4 2019, despite the fact that carbon prices climbed down from their summer record levels. Cheaper allowances and a temporary increase in power prices in the UK and Germany helped coal plant profitability in November and lifted the total EU coal generation above 20 TWh for the first time since February. However, as power contracts went lower and carbon prices recovered in December, clean dark spreads sank across the board and moved towards or deeper into negative territory. At 55 TWh, the total coal generation in the EU28 in the reference quarter was a third lower than in Q4 2018.

Figure 16 – Evolution of clean dark spreads in the UK, Spain, Italy and Germany, and electricity generation from hard coal in the EU28

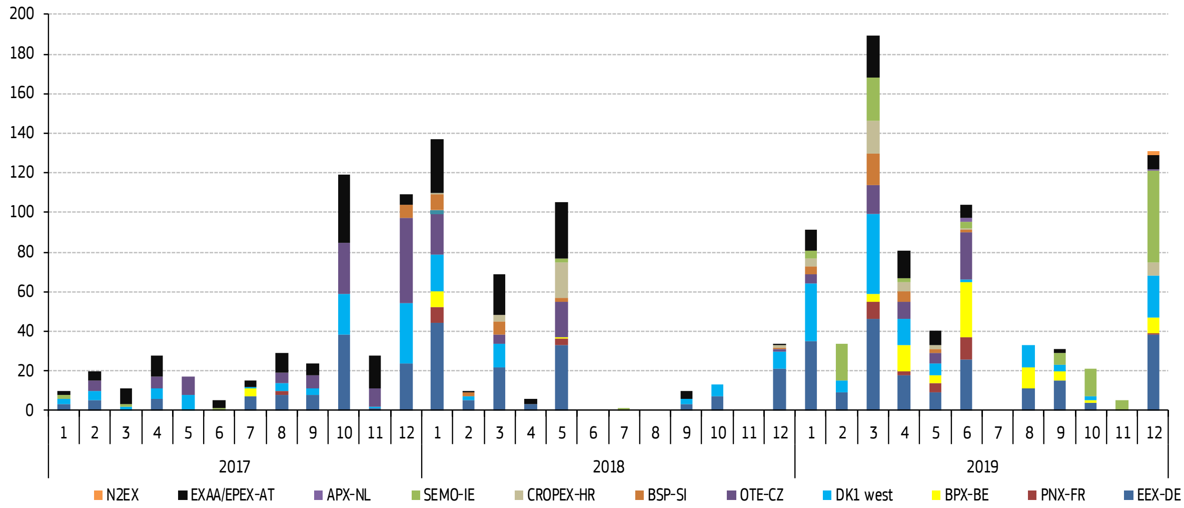


Source: ENTSO-E, Eurostat, Bloomberg

- **Figure 17** shows the monthly frequency of the occurrence of negative hourly wholesale electricity prices in selected European 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.

- At 165, the number of hours with negative wholesale prices in Q4 2019 was almost four times higher in the observed bidding zones than in the previous Q4, but 39% lower compared to Q4 2017, when hourly prices were below zero in 270 cases. Most of the falls into negative territory in the reference quarter were concentrated in December, especially before Christmas Eve when low holiday demand met with high renewable output. Another significant episode happened on December 8th when strong winds drove the total continental wind output towards 100 GW and pushed prices in Germany, Belgium, Denmark and Ireland below zero. The integrated Irish market recorded the highest number of negative hourly prices (65) in Q4 2019, overtaking Germany (42) and Denmark's western zone (24). On the Irish island, negative prices occurred not only on weekends but also on working days during night time and in the early morning when strong wind currents propelled the renewable output to cover more than half of local power demand. For the whole year 2019, the number of negative hourly prices in bidding zones under observation nearly doubled compared to 2018.

Figure 17 – Number of negative hourly wholesale prices on selected day-ahead trading platforms

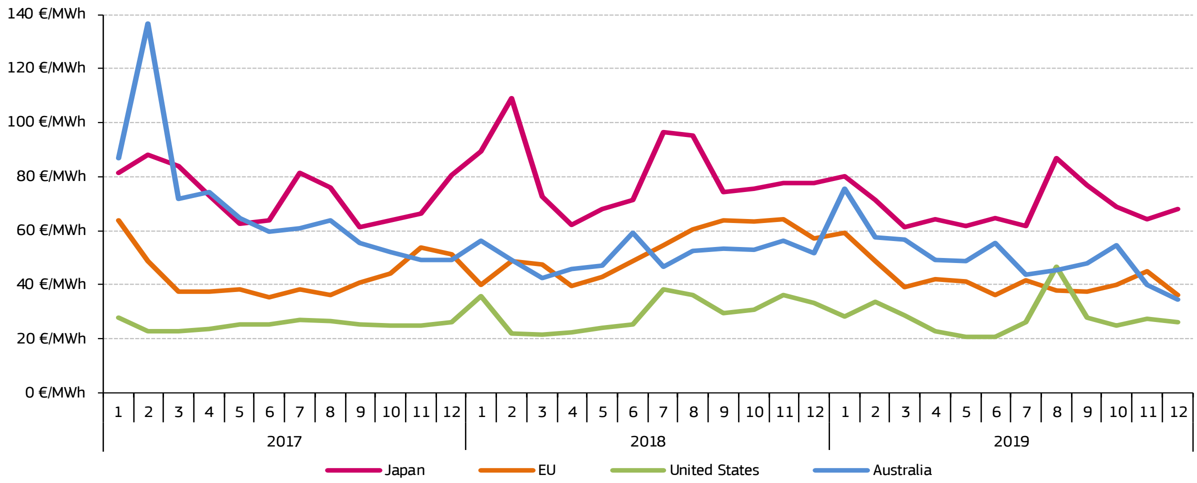


Source: Platts, ENTSO-E. For Austria, the EXAA market is used prior to October 2018, and the EPEX market is used afterwards.

- **Figure 18** compares price developments in the wholesale electricity markets of selected major economies. Japan was the most expensive of the markets under observation in Q4 2019, with day-ahead prices exceeding 65 €/MWh for most of the quarter. Meanwhile, at the other end of the spectrum, average wholesale prices in the United States moved between 20 and 30 €/MWh, thanks to the abundance of domestically produced low-cost natural gas that serves as the fuel to marginal power plants in most local electricity markets. The only exception was California (CAISO) where prices rose towards 40 €/MWh in the second half of the reference quarter.

- Wholesale prices decreased considerably in Australia across all its regional markets throughout Q4 2019, despite summer heatwaves in the Southern Hemisphere stressing the grid and causing several instances of short-term price spikes in December. Improved availability of coal capacities on the continent, which suffered from outages in October, helped push prices below the European Power Benchmark at the end of the quarter.

Figure 18 – Monthly average wholesale electricity prices in Europe, US, Japan and Australia (D-A markets)

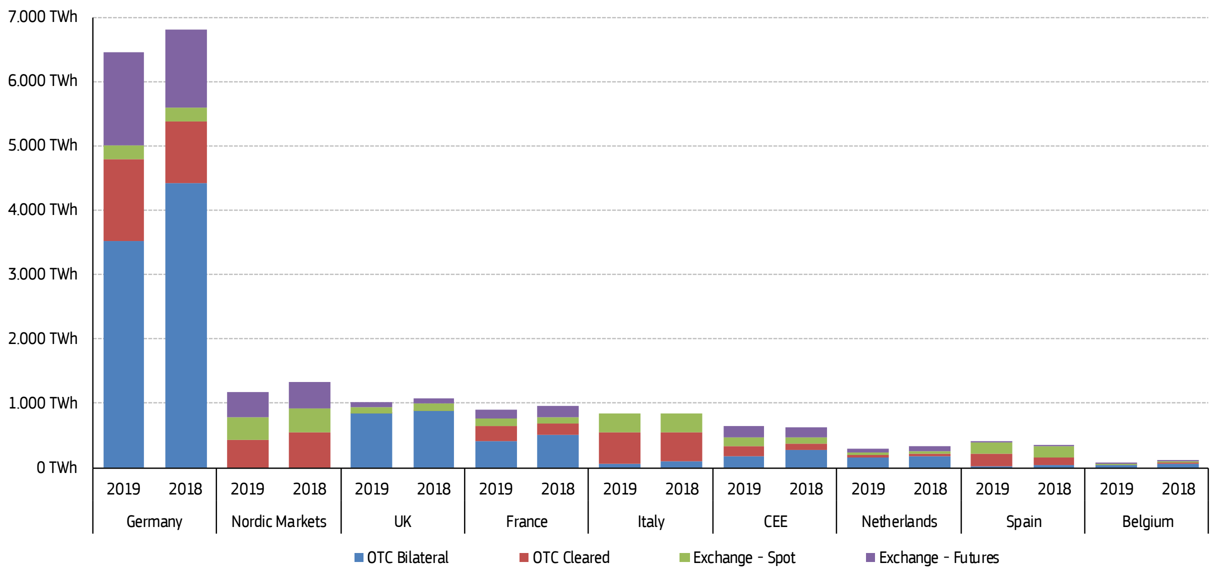


Source: European Power Benchmark, JPEX (Japan), AEMO (Australia) and the average of PJM West, ERCOT, MISO Illionois and CAISO regional wholesale markets in the United States

2.2 Traded volumes and cross border flows

- **Figure 19** shows annual changes of traded volumes of electricity in the main European markets, including exchange-executed trade and over-the-counter (OTC) trade. Most countries and regions witnessed a decline in trading activity in 2019. Spain, where volumes rose 17% year-on-year, was a notable exception. The largest annual falls in total traded volumes were registered in Belgium (-42%), the Nordic markets (-11%) and the Netherlands (-10%), mainly in the OTC sector. The total traded volume in all markets under observation in 2019 decreased by 5% year-on-year to 11,847 TWh.
- In Germany, the largest and most liquid market by far, activity increased at exchanges (+15%) and in OTC cleared deals (+33%), at the expense of OTC bilateral contracts (-20%). Thus, the long-term decline of the importance of bilateral contracts, which was partially reversed in 2017 and 2018, continued in 2019. Similar trends were visible in the CEE region where bilaterally-settled trades suffered a 41% year-on-year decline in 2019, while OTC cleared volumes more than doubled and exchange-based activity rose by 8%. Spain also registered a big increase in OTC cleared volumes at the expense of bilateral contracts. The largest falls in exchange-based volumes were reported in Belgium (-31%), the UK (-11%) and France (-8%). Overall, exchange-based trading volumes increased by 150 TWh in 2019 and expanded their share in the market to 32% from 29% in the previous year. The rise was driven mainly by futures contracts offered on German platforms (+200 TWh), which signals increased hedging demand.

Figure 19 – Annual change in traded volume of electricity on the most liquid European markets



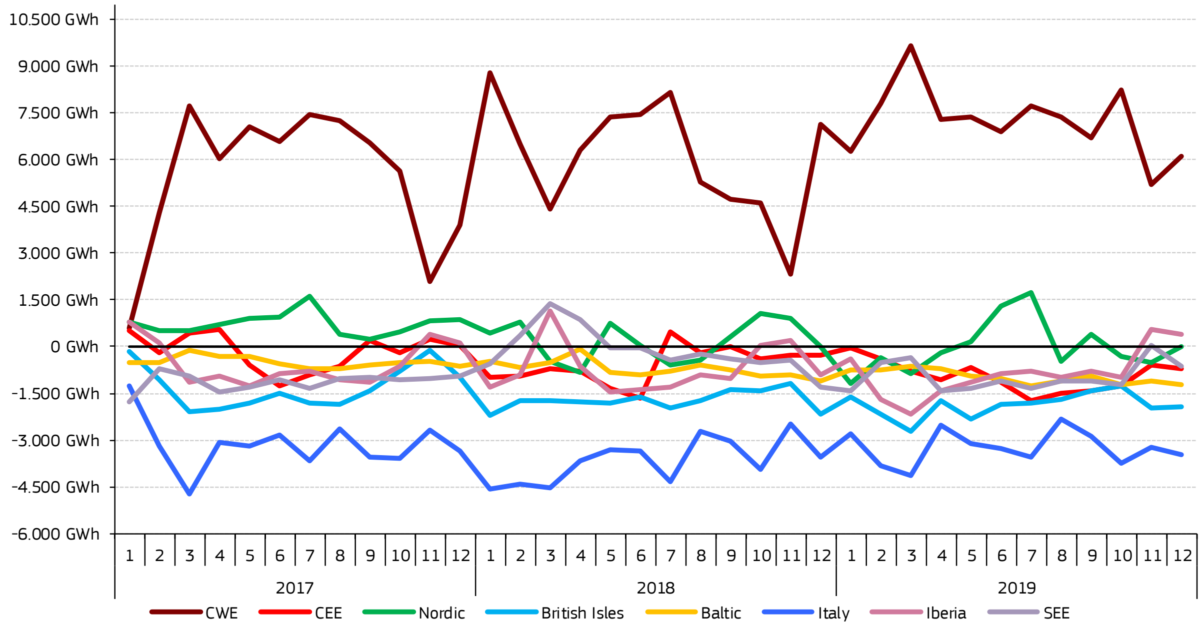
Source: Platts, wholesale power markets, Trayport, London Energy Brokers Association (LEBA) and DG ENER computations

- **Figure 20** reports on the regional cross-border flows of electricity. The CWE region retained the position of Europe's main exporter, having plentiful and diverse generation capacities, competitive prices and a central position suitable to supply all the other regions. Monthly net export flows fluctuated between 5 and 8 TWh, adding up to 19.6 TWh for the whole reference quarter (+39% compared to Q4 2018). High wind and hydro generation and a very good performance of the Belgian and Swiss nuclear fleet contributed to this result.

- As in previous quarters, Italy was the largest importer of electricity in Q4 2019, receiving 10.5 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. The net Italian position slightly worsened compared to the previous Q4 on the back of a sharp fall in coal- and oil-fired generation which was not fully compensated by rising renewable output. Exports to Greece reached 0.8 TWh on a net basis in the reference quarter, similar to the previous quarter. The second largest importing region, the British Isles, increased its net purchases in Q4 2019 by 8% year-on-year to 5.2 TWh, as lower consumption and rising renewable output could not fully make up for significantly reduced coal generation. The CEE region's net position improved in Q4 2019 compared to the previous quarter thanks to cheaper emission allowances and better availability of the Czech and Hungarian nuclear capacities. But with 2.5 TWh of net imports, it was still worse than in the same quarter last year. South Eastern Europe's balance improved in Q4 2019 compared to the previous Q4 due to a surge in hydro generation in the eastern part of the region.

- The Nordic region stayed a net importer throughout the reference quarter, receiving 0.8 TWh of inflows, as opposed to Q4 2018 when it exported 2 TWh on a net basis. This was due to a significant reduction in Norwegian hydro output which could not be entirely compensated by higher renewable and hydro generation in Sweden. The Iberian Peninsula managed to hold its exchanges with France and Morocco fairly balanced, even swinging into a net exporter position in the second half of the reference quarter thanks to a surge in wind and hydro output. This was the first time the region had a positive balance since November 2018.

Figure 20 – European cross border monthly physical flows by region

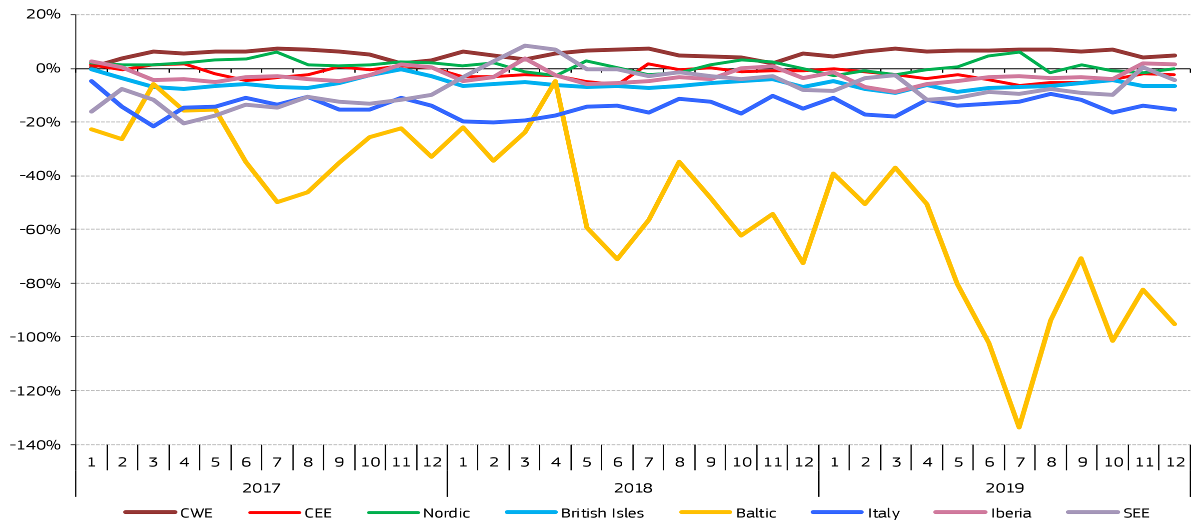


Key to country distribution in regions: CWE (AT, DE, BE, NL, FR, CH), CEE (CZ, HU, PL, SK, SI, RO), Nordic (DK, SE, FI, NO), Baltic (LT, LV, EE), Iberia (ES, PT), SEE (BG, GR, HR, RS, BA, ME, MK, AL), British Isles (UK, IE), Apennine Peninsula (IT, MT). Source: ENTSO-E, TSOs

- **Figure 21** 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 Q4 2019, the position of the Baltic region stabilized compared to the previous quarter, as it imported slightly less electricity than what was generated domestically. High shares of imports indicate difficulties facing domestic generation assets or more favourable price conditions in neighbouring areas. Carbon prices, which greatly influence the competitiveness of oil shale power plants in the Baltic region, played a crucial role in region's deteriorating balance of flows in 2019.

- Italy remained the second biggest importer relative to its production (15%). For the rest of the regions, net imports (or exports) did not exceed 10% of domestic generation. 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 Q4 2019, net CWE exports corresponded to 5% of the total regional generation.

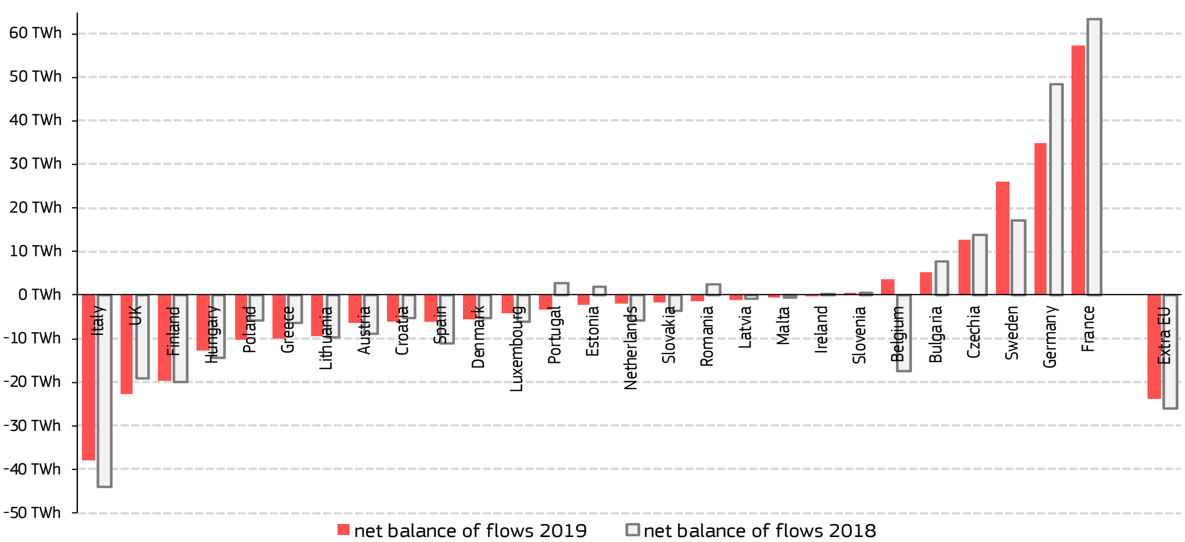
Figure 21 – The ratio of the net electricity exporter position and the domestic generation in European regions



Country distribution in regions is the same as in the previous figure. The -100% level means the same amount of electricity is imported as produced domestically. Source: ENTSO-E, TSOs, Eurostat, DG ENER calculations

- **Figure 22** compares net balances of physical flows among EU28 Member States in 2018 and 2019. France and Germany remained the two largest electricity exporters in 2019, although their combined outflows declined by 20 TWh due to numerous outages of French nuclear capacities (see **Figure 34**) and exceptionally high generation volumes of the Belgian nuclear fleet that pushed the less competitive German coal and lignite power stations out of the merit order and turned Belgium into a net exporter after 10 years. Record high generation of Swiss and Austrian hydro power plants also curbed French and German outflows. Sweden strengthened its position as the Scandinavian export leader, increasing its net outflows by 9 TWh year-on-year in 2019. This was achieved with the help of increased hydro and wind generation, mainly at the expense of Norway that significantly reduced production from its hydro reservoirs and curtailed annual net exports to the EU by 10 TWh to zero. Thus, the operator of the Norwegian hydro fleet gave priority to keeping the reservoirs at an elevated level in 2019. The fact that the Czech and Bulgarian net exports fell despite stable (and in the Czech case even slightly higher) nuclear generation shows the effect of increased carbon prices on coal-fired capacities in both countries. More expensive emission allowances also undermined the profitability coal- and lignite-based generation in Poland and Greece and contributed to a worsened net position of both countries in 2019. Meanwhile, expanding renewable penetration and lower consumption helped Italy and Spain reduce their net imports measurably. Net extra-EU28 imports slightly decreased to 24 TWh in 2019. The main sources of these flows were Russia (13 TWh), Ukraine (4 TWh) and Switzerland (3 TWh). The value of the net electricity imports coming from outside of the single market was assessed at about €1.2 billion.

Figure 22 – Member States' net export/import positions within the EU28 in 2018 and 2019



Source: ENTSO-E, TSOs, Eurostat.

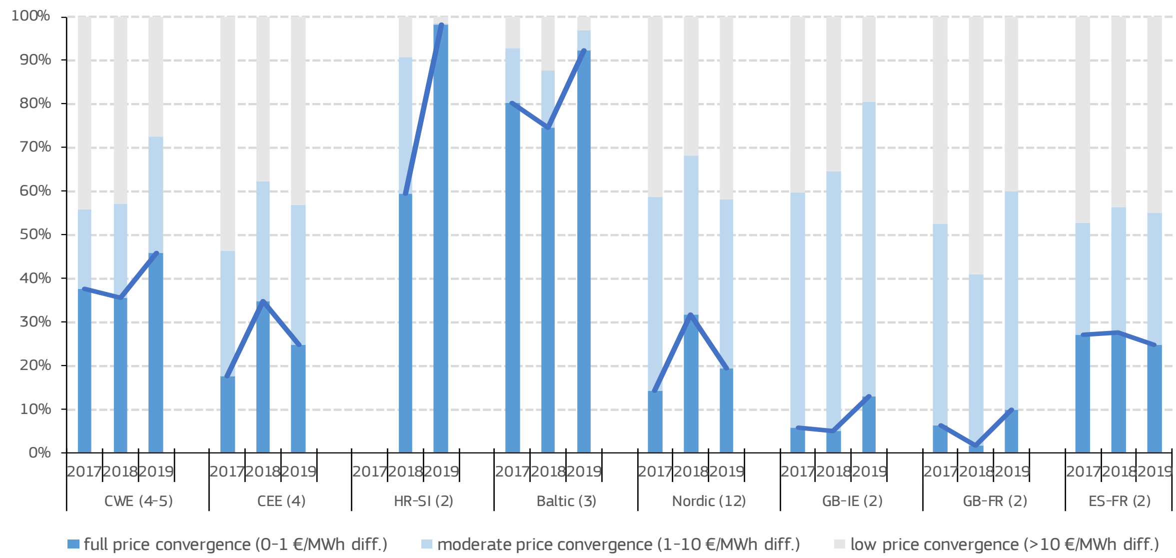
3 Focus on developments in annual wholesale prices

3.1 Hourly price convergence

- **Figure 23** illustrates the degree of price convergence in day-ahead markets within selected European regions expressed in percentages of hours in a given year. The price convergence provides an indication of the level of market integration. Its longer-term drivers are market coupling initiatives or the expansion of transmission infrastructure. In the short term, fluctuations in convergence may also be caused by factors not necessarily related to the level of market integration, such as or changes in the amount of cross-zonal capacity designated by TSOs for commercial purposes, longer outages of transmission lines, or significant fluctuations in the power mix.

- Overall, the European electricity markets saw mixed developments in 2019. In the CWE region, which is the only one where flow based market coupling has been applied since 2015, the number of occurrences of full price convergence (when the difference between hourly prices in all bidding zones falls within 1 €/MWh) increased noticeably in 2019 compared to the previous year (from 36% to 46% of hours). The decreasing divergence occurred despite the splitting of the DE-LU-AT bidding zone, which came into effect in October 2018 and which increased the number zones in the region from four to five. This could be explained by the fact that full price convergence between the partitioned zones (between DE-LU and AT) turned out to be relatively high, at 72% of hours in 2019. A considerable increase in full price convergence occurred also within the Baltic region, despite its greatly increased import dependence (see **Figure 21**), and between Croatia and Slovenia, where hourly prices were nearly identical 98% of the time in 2019. Price convergence also rose across the British Isles, following the implementation of market coupling between Great Britain and the Irish Integrated Single Electricity Market in October 2018. A new 1 GW interconnector linking Great Britain and the continent since January 2019 contributed to the rise in price convergence between France and Great Britain. On the other hand, decreases in price convergence were observed in the CEE and Nordic regions and between Spain and France in 2019.

Figure 23 – Price convergence on day-ahead markets in selected regions as percentage of hours in a given year

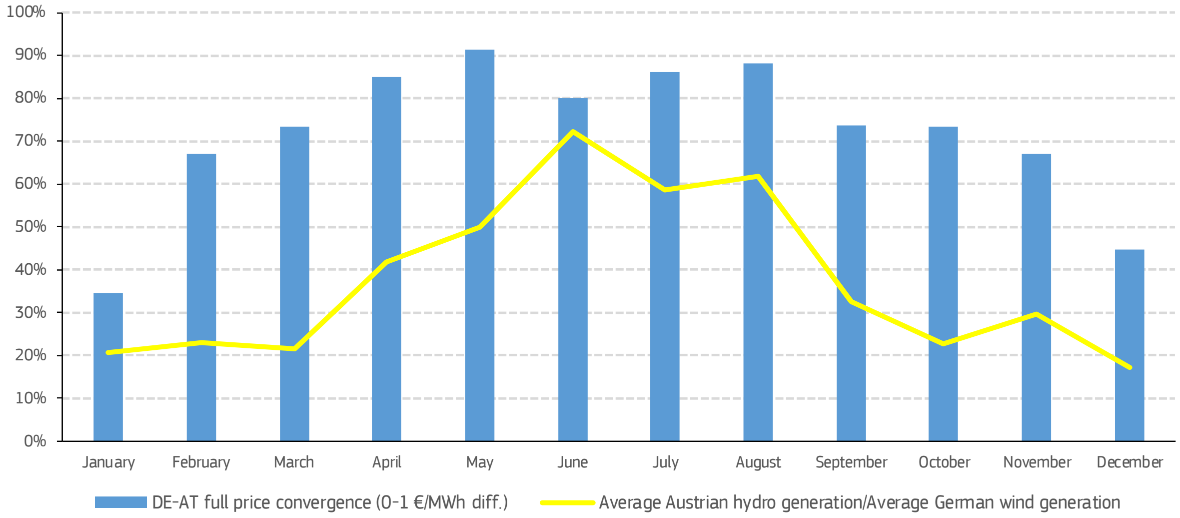


Source: ENTSO-E, OTE, Nord Pool, Platts. The numbers in brackets refer to the number of bidding zones included. The CWE region comprises of BE, FR, NL and DE-LU-AT zones until October 2018, and separate DE-LU and AT zones since then. The CEE region includes CZ, SK, HU, RO bidding zones which are coupled. The Baltic region includes EE, LV, LT bidding zones. The Nordic region includes 12 bidding zones of Norway, Sweden, Finland and Denmark.

- **Figure 24** demonstrates that price convergence is subject to seasonal fluctuations and that it changes from month to month. In the case of the newly established Austrian bidding zone and the common zone of Germany and Luxembourg, full price convergence was generally lower during winter months in 2019 when electricity consumption was higher and the grid was under greater stress. At the same time, Austrian hydro generation, the most important source in the country, was at its lowest in winter months, necessitating higher imports from Germany, which in turn saw seasonally stronger wind generation in those months influencing prices to a greater extent than during the rest of the year.

- Expected adjustments in the capacity calculation methodologies and the application of the cross-zonal capacity targets set by [Regulation (EU) 2019/943](#) on the internal market for electricity, together with the completion of market coupling (Greece remains to be coupled), are expected to increase price convergence across Europe. Another strong impetus towards greater convergence should be provided by a number of interconnectors scheduled to come online in the next few years. The Nordic border transmission capacity should expand from 7 GW at the beginning of 2020 to 14 GW by 2030. Half of that capacity should be linked to Germany. Two new cables linking Great Britain and France with a total capacity of 2 GW are scheduled to start operating in 2020.

Figure 24 – Monthly full price convergence between the bidding zones of Austria and Germany-Luxembourg as percentage of hours in 2019

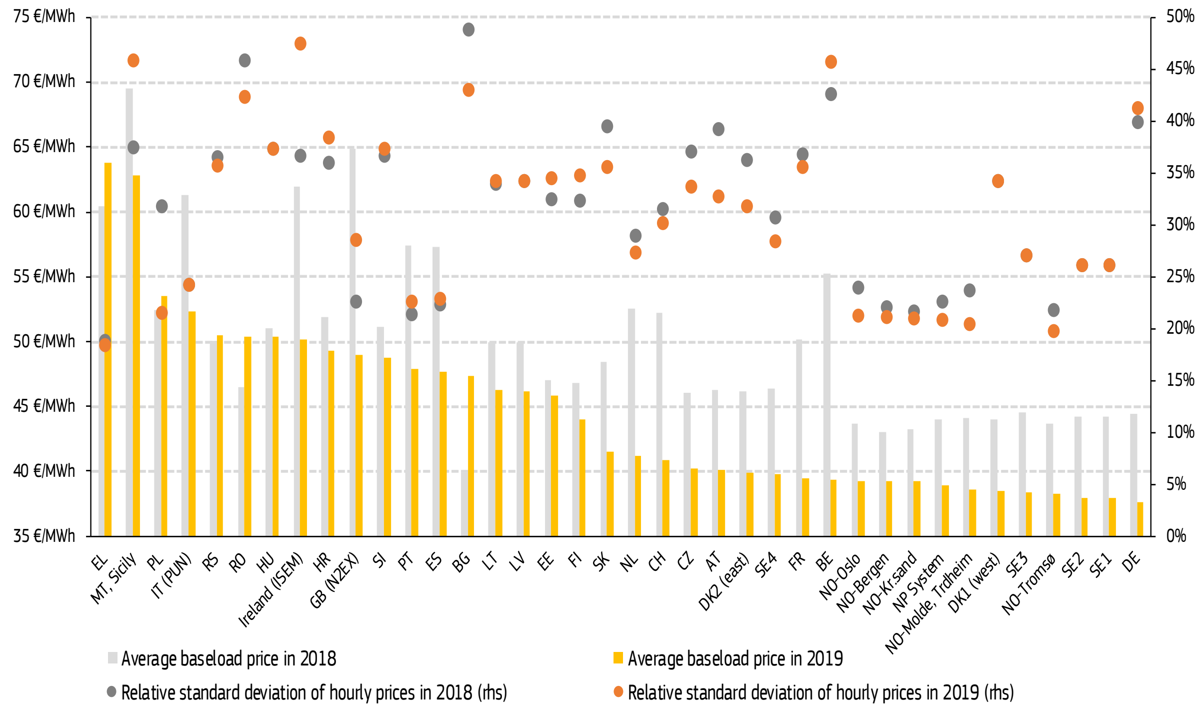


Source: ENTSO-E

3.2 Average annual price levels, volatility and occurrence of low prices

- **Figure 25** maps annual changes in average day-ahead baseload prices and in hourly price dispersion across European day-ahead markets. Overall, rising renewable generation, lower gas and coal prices and weaker demand more than compensated for increasingly expensive emission allowances, driving baseload prices in most bidding zones lower year-on-year. Only three markets (Bulgaria, Romania and Greece) experienced significant increases in wholesale electricity prices between 2018 and 2019, driven by pricier carbon punishing lignite generation (especially Greece and Bulgaria), relatively weak hydro output (Bulgaria and Romania) and higher electricity consumption (Bulgaria and Greece). On the other side of the spectrum, Belgium, Great Britain, the Netherlands and France saw baseload prices declining in 2019 by more than a fifth annually thanks to rising renewable penetration, falling gas prices, more interconnection capacity (Cobra and Nemo links), improved nuclear fleet performance (Belgium) and falling consumption (all markets except the Netherlands). With an annual average of less than 38 €/MWh (down 15% year-on-year), Germany replaced Bulgaria as the zone with the lowest wholesale prices in 2019.
- Three quarters of bidding zones saw similar or lower levels of price volatility (measured as relative standard deviation of hourly prices and plotted on the right-hand scale of the chart) in 2019 compared to the previous year. A notable development occurred on the British Isles (ISEM and N2EX) where despite a large decline in average prices, hourly price dispersion rose significantly. This could be partly explained by shifting demand patterns, a decreased presence of large baseload-providing sources (coal, nuclear) in the British and Irish mix and rising renewables penetration, which have had an outsized impact on price stability in a relatively secluded island system with limited interconnection capacities to the continent. High price volatility could be observed in other markets suffering from low cross-border interconnection (Malta) or high renewable penetration (Germany). Poland, on the other hand, experienced the largest fall in price volatility, which could be traced to increased cross-border trading capacities designated by the local TSO that allowed more imports to help cover demand peaks and dampen daily price variation.
- Greater dispersion of hourly prices offers opportunities for flexibility providers such as demand response, pumped hydro storage or battery storage (see **Figure 31**). The average difference between the highest and the lowest hourly price within one day in 2019 in Sicily (which sets wholesale prices for Malta) was 72 €/MWh. In Ireland, the same indicator reached 54 €/MWh.

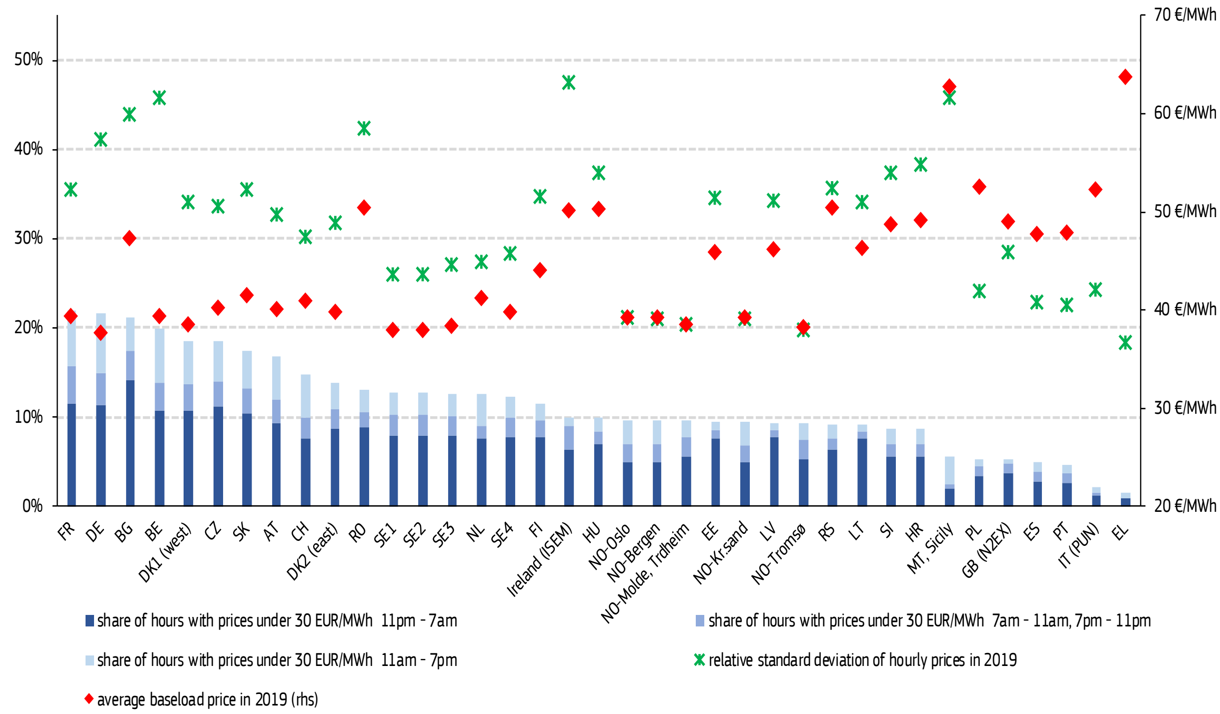
Figure 25 – Changes in average baseload prices and hourly price volatility in European day-ahead markets between 2018 and 2019



Source: ENTSO-E, OTE, Nord Pool, Platts. Italy is represented by the national average (PUN), the rest of the markets under observation correspond to bidding zones. Ireland has a common bidding zone with Northern Ireland (ISEM). Prices in Great Britain are represented by the N2EX power market. For Austria, which has its own zone since October 2018, common zone (DE-LU-AT) prices have been used for the period preceding the split.

- At times of high renewable or nuclear generation and/or low electricity demand, significant parts of thermal capacities with higher operating costs are crowded out of the market, which pushes prices to low levels. **Figure 26** shows the share and time distribution of hours in individual bidding zones when prices dropped below 30 €/MWh in 2019. This threshold roughly corresponds to a level under which most thermal power plants would struggle to cover their operating costs, given the average prices of carbon allowances and fuel inputs in 2019.[3] Average baseload prices (right-hand scale) and hourly price volatility (left-hand scale) are also displayed. Germany and France, the two largest exporters on the continent, top the list, registering low prices for more than 20% of hours in 2019. The high presence of cheap nuclear power accompanied by relatively large hydro capacities and a growing renewable base help explain the French case. Wind and solar capacities in excess of 100 GW contribute a great deal in keeping prices down in Germany. But the issue at hand is more complex and is influenced also by demand patterns, the shape of the merit order curve and interconnection capacities. Two thirds of power generated in Denmark's mainland (zone DK1) were supplied by wind and solar sources in 2019, and yet it registered the same amount of low-priced hours as Czechia where low-cost renewable generation did not exceed 10% in the same year, but where hourly prices are strongly correlated with the neighbouring German market.
- Average baseload prices alone offer only limited guidance for the occurrence of low prices. The Bulgarian average baseload price for 2019 was very similar to those in Spain and Great Britain, but the number of Bulgarian hourly prices below the 30 €/MWh threshold was four times higher than in Spain and Great Britain. The lowest amount of low prices occurred in Greece and Italy, markets with relatively high average prices and low price volatility.

Figure 26 – Instances and distribution of prices below 30 €/MWh in European day-ahead markets in 2019 compared to average baseload prices and their volatility

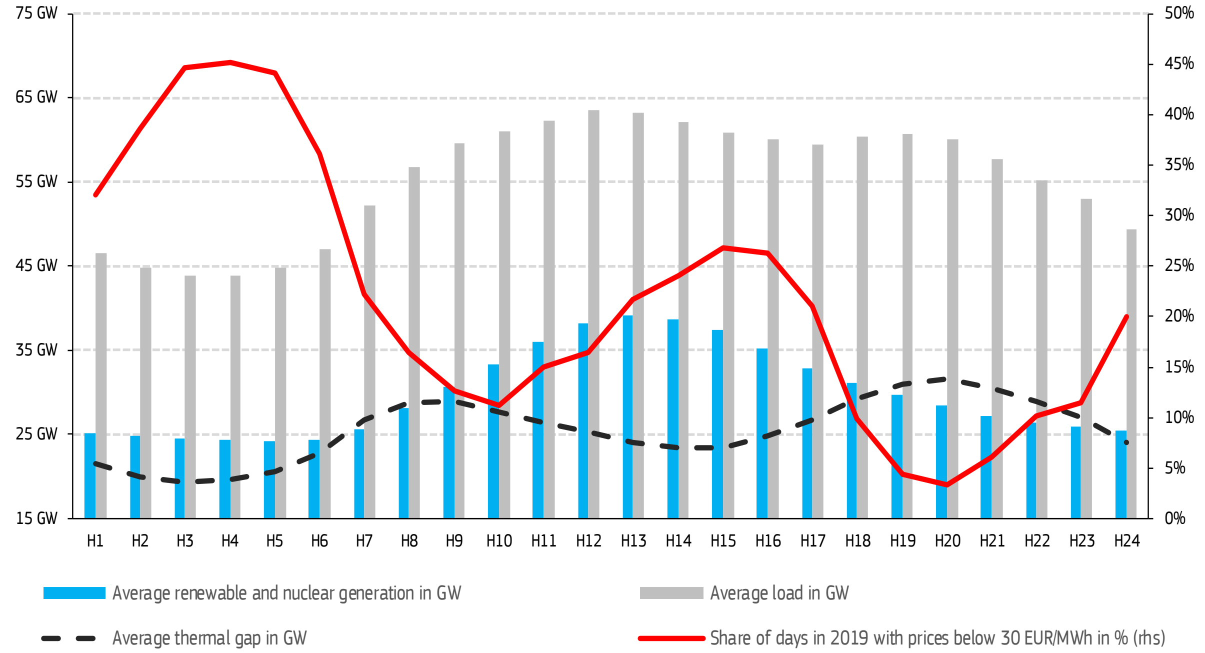


Source: ENTSO-E, OTE, Nord Pool, Platts. Italy is represented by the national average (PUN), the rest of the markets under observation correspond to bidding zones. Ireland has a common bidding zone with Northern Ireland (ISEM). Prices in Great Britain are represented by the N2EX power market. For Austria, which has its own zone since October 2018, common zone (DE-LU-AT) prices have been used for the period preceding the split. Prices for Malta are the same as in the Sicilian bidding zone.

[3] Average short run marginal costs for lignite generation in 2019 were assessed at 27 €/MWh in 2019, assuming an average power plant with 36% efficiency, emissions of 1.1 t CO2/MWh of electricity produced, an average 2019 carbon price of 25 €/t and zero fuel costs. For a typical CCGT (gas) plant the same costs were assessed at 32 €/MWh, assuming 58% efficiency, an emission factor of 0.35 t CO2/MWh, and average 2019 carbon price (25 €/t) and gas price (13.5 €/MWh). For a typical coal-fired power plant, short run marginal costs were assessed even higher, at 38 €/MWh.

- The hourly distribution of low prices reveals their high dependence on power demand. In nearly all bidding zones under observation, they were most common at night, when electricity consumption typically ebbs, and least common during morning and evening peaks. **Figure 27,** which focuses on the German market exclusively, explores this in greater detail by following average load (a proxy for consumption) in individual hours of the day in 2019. As the red line in the chart shows, the highest incidence of low prices was registered between 2am and 5am (H3 - H5) when consumption was typically at its lowest. At that time, prices fell under 30 €/MWh almost every other day. However, later on the load profile ceases to be a reliable guide to the occurrence of low prices. The red line points to the smallest concentration of low prices between 7pm and 8pm (H20) even though the average consumption during that hour is not at its daily maximum. And it shows a second peak in low pricing between 2pm and 3pm (H15) when the afternoon lull in consumption is still two hours away. The discrepancy can be explained by the fact that renewable and nuclear generation on average follow a pattern (blue columns in the chart) that does not correspond to consumption levels. Its variations are greatly influenced by the large solar capacity that typically reaches its highest output in the early afternoon, dampening the effect of peak demand on prices in those hours. In order to more precisely account for renewable penetration in the German mix, the difference between the average load and the average low-cost renewable and nuclear generation in individual hours was included in the chart. The result, the hourly thermal gap (in other words the room left in the merit order for thermal power plants in each hour of an average day), better explains price developments in the day-ahead market. The larger it is, the less instances of low prices can be observed. In 2019, this gap reached a maximum above 31 GW between 7pm and 8pm (H20) when solar output stops playing any meaningful role in the mix. The hourly price dived below 30 €/MWh in less than 5% of the days during this hour. The thermal gap's midday trough came between 2pm and 3pm (H15) as low prices registered their midday high at more than 25% of instances during 2019. As solar PV capacities in Germany (and in others as well) keep growing at a fast clip (see **Figure 14**), this trough will most probably get deeper in the future.

Figure 27 – Average daily load profile and thermal gap profile in 2019 compared to the occurrence of day-ahead hourly prices below 30 €/MWh in Germany



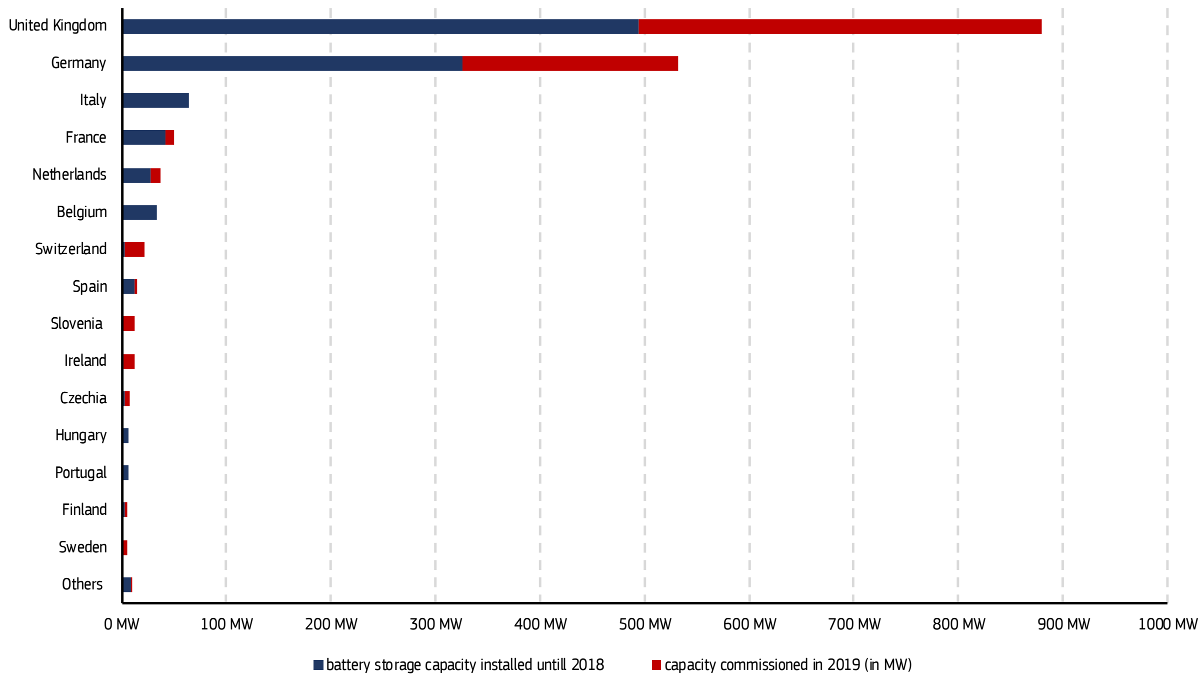
Source: ENTSO-E, Platts. The x axis shows individual hours of the day in CET. The average renewable and nuclear generation columns do not include biomass. The thermal gap represents the difference between the grey and blue columns.

- Keeping track of volatility and spotting the moments when wholesale prices are relatively low offer opportunities not just for utilities, aggregators or large industrial companies. A growing array of innovative tools such as dynamic contracts or smart home apps allow households or smaller businesses to actively participate in the electricity market and save costs. This will focus more attention on the wholesale markets and may pose new challenges in terms of their functioning, resilience and transparency.

4 Focus on energy storage

- The rising presence of intermittent renewable energy in the electricity mix combined with the intensified decentralisation of generation sources presents ever-increasing demands on the management of the grid. In this environment, energy storage gains greatly in importance since it increases system's ability to accommodate variable wind and solar output, balance fluctuations in supply and demand, or to deal with local congestion issues. A broad range of storage technologies with varied characteristics regarding capacity, efficiency, duration and response time are being introduced to the market to maintain grid stability, voltage control, as operating reserve, dispatch and re-dispatch as well as for simple price arbitrage.
- To clarify the position of energy storage in the electricity market and ensure that it can contribute with its full potential to the decarbonisation of the economy, energy storage was defined in the recently adopted Directive (EU) 2019/944 on common rules for the internal market for electricity. Additionally, Member States' energy policies should not be designed in a way that unduly discriminates energy storage compared to other players and technologies. To ensure market competition and keep costs down, TSOs and DSOs are restricted from owning and operating energy storage facilities, except under special circumstances. Thus, storage can be offered as a service to DSOs, e.g. for congestion management, or TSOs for frequency regulation. Member States have to incorporate the necessary adjustments into their national law by 2021.
- Batteries represent one of the fastest expanding energy storage technologies. Thanks to their quick response times, their capacities are increasingly procured in the ancillary services market for the purpose of frequency control. They can also be used to meet demand peaks or for energy shifting. The latter means that energy is stored at times of low prices and surplus supply, and discharged at a later point when scarcity in the system drives power prices up. Additionally, battery facilities can be used as an alternative to network reinforcements that might require expensive upgrades. Batteries also offer a way to optimise self-consumption from in-house renewable generation sources, be it at industrial or residential scale. Last but not least, their use in electrically chargeable vehicles makes batteries on of the key enablers of a low-carbon economy.

Figure 28 – Installed capacity of utility-scale electrochemical battery storage projects in Europe



Source: BloombergNEF, Enerdata, DG ENER

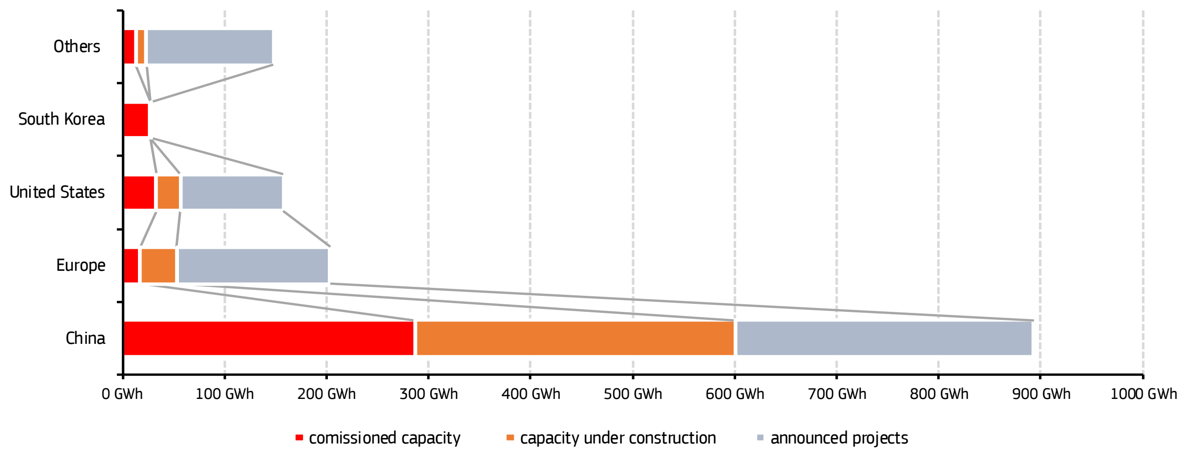
- **Figure 28** maps the landscape of operational utility-scale battery storage projects across Europe. The UK emerges as the leading market, both in terms of total capacity (880 MW) and new facilities commissioned in 2019 (400 MW). Storage operators in the country benefit from favourable regulatory environment, which presents several sources of revenue. The capacity market with its regular auctions has been an important driver of new installations. The same holds true for ancillary services market in which storage facilities can offer frequency response services procured by the TSO. Most recently, new opportunities have opened up in the balancing market. Changes introduced by the system operator in December 2019 to the local balancing mechanism (e.g. lowering the participation threshold from 100 MW to 1 MW) will greatly enlarge the circle of potential new entrants, especially among storage facilities. In addition, co-located renewable and storage installations are spreading across the country, often with the backing of local authorities. This helps solar projects to be developed without subsidies, or onshore wind farms to increase their output by avoiding curtailment in congested parts of the network.

- In Germany, where more than 200 MW of additions in 2019 drove the total installed capacity to roughly 530 MW, utility-scale batteries have found use mainly in the ancillary services market. However, planned changes in the regulatory environment, rising renewables penetration and announced closures of thermal generation capacities should create new opportunities here as well. The German regulator recently announced a project that will explore the use of storage systems as substitutes for investments in new or reinforced network infrastructure. Other markets have seen far lower levels of battery storage deployment, but a few (Switzerland, Slovenia, Ireland, Czechia, Finland and Sweden) have experienced large relative expansions. The French TSO is pursuing a project similar to the one in Germany in which battery storage is used to manage grid congestion. Meanwhile, installations have been mostly developed in French overseas territories or on islands. In Italy, as in many other markets, battery storage faces competition from demand response and pumped hydro storage. As for the technologies employed, lithium-ion batteries clearly dominate, making up around three quarters of installed capacity across Europe. Other technologies used in recently finished projects include lead acid, redox flow, sodium-based or vanadium-based batteries.

- Additional important area of growth for battery systems has been residential storage paired with self-generation. Significant declines in investment costs and a gradual phase-out or lowering of feed-in tariffs incentivize consumers to store their surplus PV generation in order to use it later. Germany, which saw 55,000 home storage units (totalling 230 MW in power output) installed in 2019, is by far the biggest European market. The deployment of storage systems was spurred by a subsidy scheme administered by the development bank KfW, which provided gradually lowered grants covering almost a third of the investment costs at the start and about a tenth of it towards the end of the programme in 2018. There are also local support schemes provided by some German states. In Italy, self-generating households with battery storage are eligible for an income tax rebate of up to 50% of the system cost. This incentive, together with relatively high retail electricity prices and low remuneration for excess electricity injected into the grid, work as a strong driver of battery storage uptake. According to the Italian TSO's estimates, one in 10 newly installed residential PV systems in the country comes with a battery. In the UK, where only a reduced VAT rate on the purchase of a residential PV+storage system is offered, the providers are exploring alternative ways to encourage household uptake, such as aggregating these systems so that they can participate in the ancillary services market and generate additional revenues.

- Thanks to the virtuous circle of rising use and increased investments, battery pack prices fell by nearly 90% in the last decade according to Bloomberg New Energy Finance estimates. The expected expansion of battery demand from electric vehicles, consumer electronics and stationary energy storage systems is igniting massive investment across the supply chain, as demonstrated by **Figure 29** which maps operational, currently built and planned lithium-ion battery cell manufacturing capacities in factories around the world. Today, the majority (76%) of commissioned cell production capacities are located in China, which should retain its strong position thanks to a large number of new projects either under construction or announced in the country. Nevertheless, China's share of the market is expected to decrease as incumbent and new manufacturers establish plants near significant sources of potential demand, especially in Europe. Its cell manufacturing base should expand rapidly from 17 GWh/year currently to more than 200 GWh/year in 2024, with most additions coming from Poland (60 GWh), Germany (44 GWh), Sweden (32 GWh), Norway (32 GWh) and Hungary (16.5 GWh).

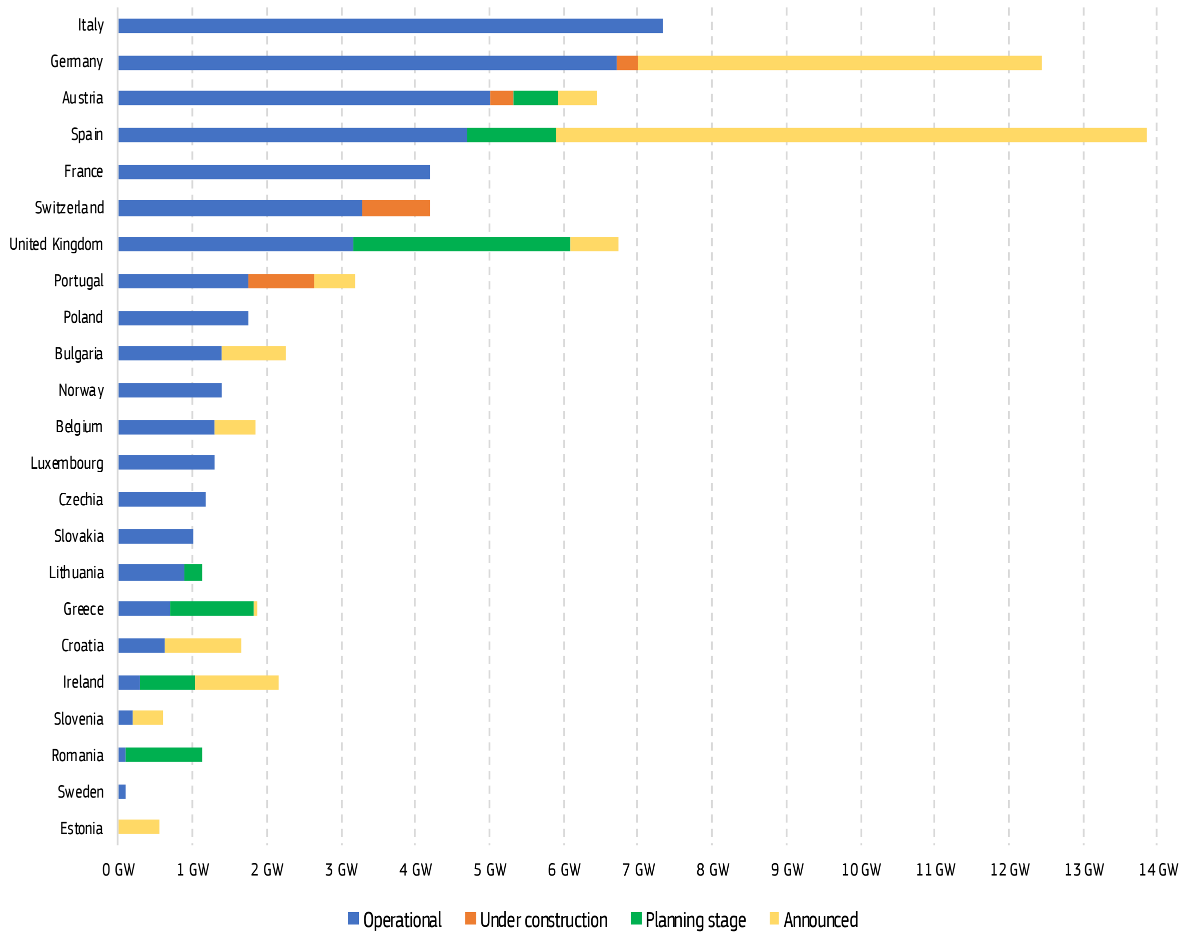
Figure 29 – Current and expected global lithium-ion battery cell manufacturing capacity



Source: BloombergNEF

- The growth of European-based manufacturing capacities in this important sector is supported by the European Commission, which together with interested Member States and key industrial and financial stakeholders founded [the European Battery Alliance](#) in 2017. The aim of the initiative is to create a competitive manufacturing value chain in Europe with sustainable battery cells at its core and to capitalize on the employment, growth and investment potential of batteries.
- Pumped hydro represents one of the oldest and most mature ways to store energy. With an efficiency factor of about 80% and very fast response times, it accounts for 97% of EU's current energy storage capacity. Pumped hydro storage plants typically help with meeting morning and evening demand peaks. Although it might seem that most of their potential on the continent has been already exploited, new projects that are either under construction or still on the drawing board could increase the total installed capacity by more than half. **Figure 30** explores the latest developments in greater detail. The total installed capacity in the EU27 stood at 42 GW at the end of 2019, with two thirds concentrated in five countries (Italy, Germany, Austria, Spain and France). Pumped hydro storage plants with a combined capacity of 1.5 GW are under construction and additional 5 GW are in various planning stages (they have either received authorization or submitted a request for permission or were in the bidding process). Further 19 GW of new projects have been announced, most of them in Germany and Spain. Plans for new capacities are also pursued in the UK and Switzerland. One new larger plant was brought online in 2019 in Austria (360 MW Obvermunt II), another was retrofitted with a stronger turbine in France (La Coche in Savoy). Between 2010 and 2018, around 3.3 GW of new capacity was commissioned in the EU27, mainly in Austria (1.3 GW), Portugal (0.9 GW) and Spain (0.9 GW).

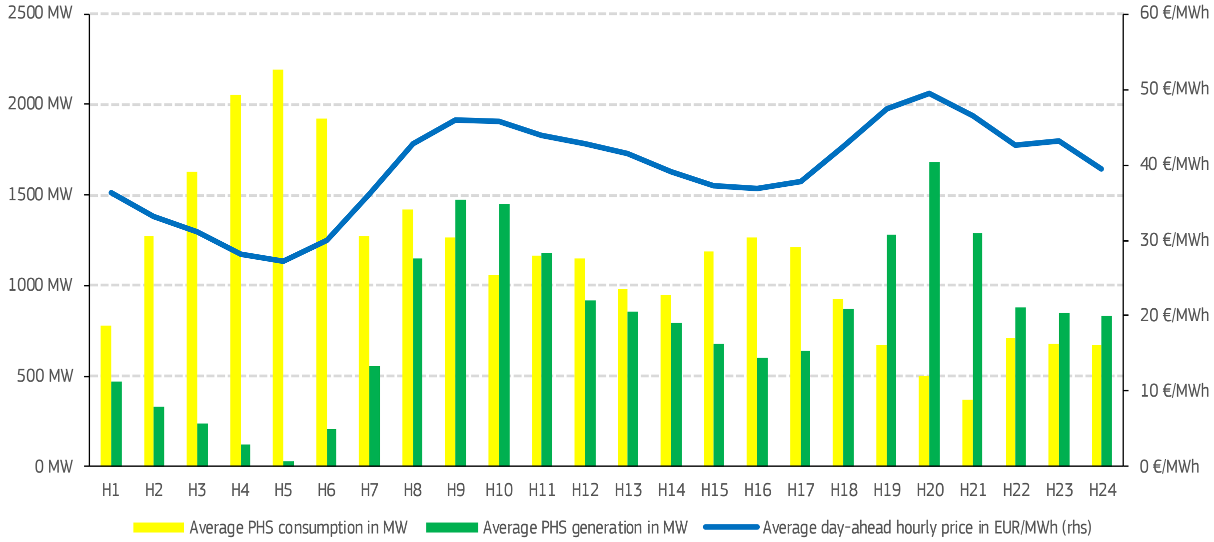
Figure 30 – Operational, planned and announced pumped hydro storage capacities in Europe



Source: Enerdata, ENTSO-E. Capacities refer to the output of turbines, not the pumps.

- **Figure 31** illustrates the use of pumped hydro storage on the example of French capacities in 2019. Pumping usually peaked in the early morning hours, when average hourly prices on the day-ahead market reached their nadir, and then increased again in the afternoon, when prices were pushed down by lower demand and high solar output. Generation from turbines reacted conversely to price developments, culminating during morning and evening peaks. In total, 5.4 TWh of electricity was consumed by pumps and 5.0 TWh generated by turbines in 2019, which suggests a relatively high efficiency rate of 87%.

Figure 31 – Daily profile of average pumped hydro storage consumption and generation in France in 2019



Source: ENTSO-E

- This overview of storage technologies is not exhaustive. Its aim is to show developments in the more mature segments of the market. Several other platforms with different potential and parameters exist, such as solar thermal power plants, which store excess energy produced during peak sunlight in heated molten salts and later use the heat to generate steam that drives a turbine. In liquid air energy storage systems, electricity is used to cool air until it liquefies and is stored in a tank. Exposure to ambient temperatures then causes quick re-gasification and a massive expansion of volume that is used to power a turbine to generate electricity. This way, energy can be stored for weeks, providing a longer-term hedge for times of decreased renewable generation. Research and innovation constantly push the boundaries and offer new solutions.

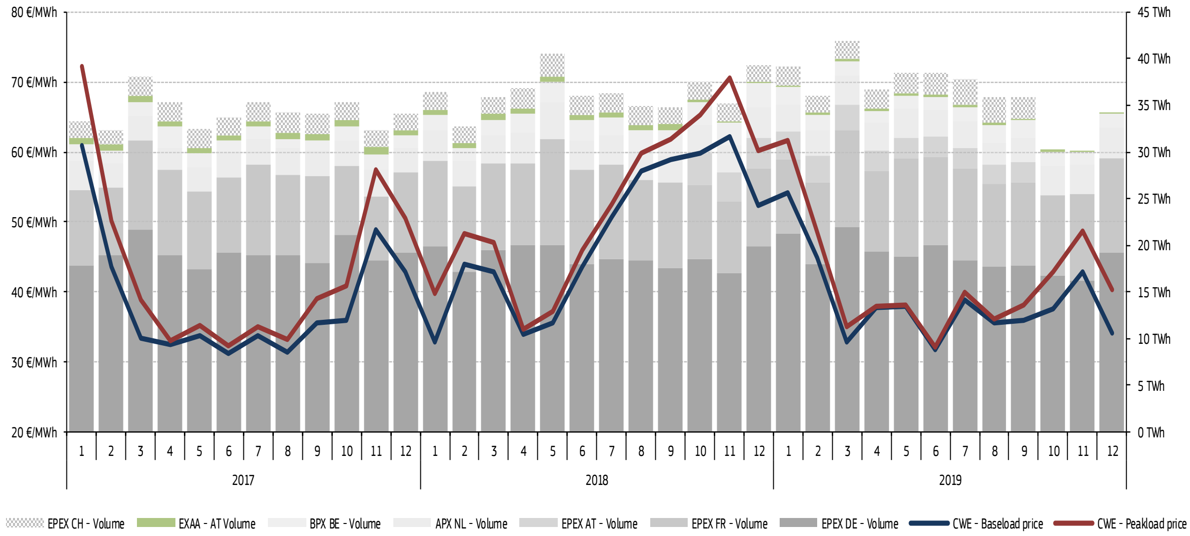
5 Regional wholesale markets

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

- Monthly average baseload electricity prices in the Central Western Europe (CWE) region were on an upward trajectory in the first half of the reference quarter, rising above 43 €/MWh in November amid more expensive gas contracts, underwhelming wind output and limited availability of the French nuclear fleet. An abrupt turnaround came in December, as mild and wet weather and record high wind and hydro output pushed the regional average under 35 €/MWh, the lowest level since June. Compared to Q4 2018, the average baseload price in the region declined by 34% to 39 €/MWh in the reference quarter, but was up 5% compared to Q3 2019. Average peakload prices registered a widening spread of 5-6 €/MWh above their baseload peers throughout the reference quarter, in line with regular seasonal trends caused by a decreased presence of solar generation energy in the mix.

- Reduced generation of French nuclear capacities, decreased competitiveness of German coal and lignite capacities and high rainfall in the Alps impacted generation volumes and cross-border flow patterns in the region. Thus, Switzerland recorded an 18% year-on-year jump in generation in Q4 2019 thanks to higher hydro and nuclear output. Belgium benefited from improved availability of its nuclear fleet and registered a 38% year-on-year rise in total generation, while the Dutch production volumes increased thanks to high gas and biomass generation. In absolute terms, the combined generation volumes of Austria, Switzerland, Belgium and the Netherlands increased by 10 TWh, while the combined German and French generation fell by 9 TWh in the reference period.

Figure 32 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Central Western Europe

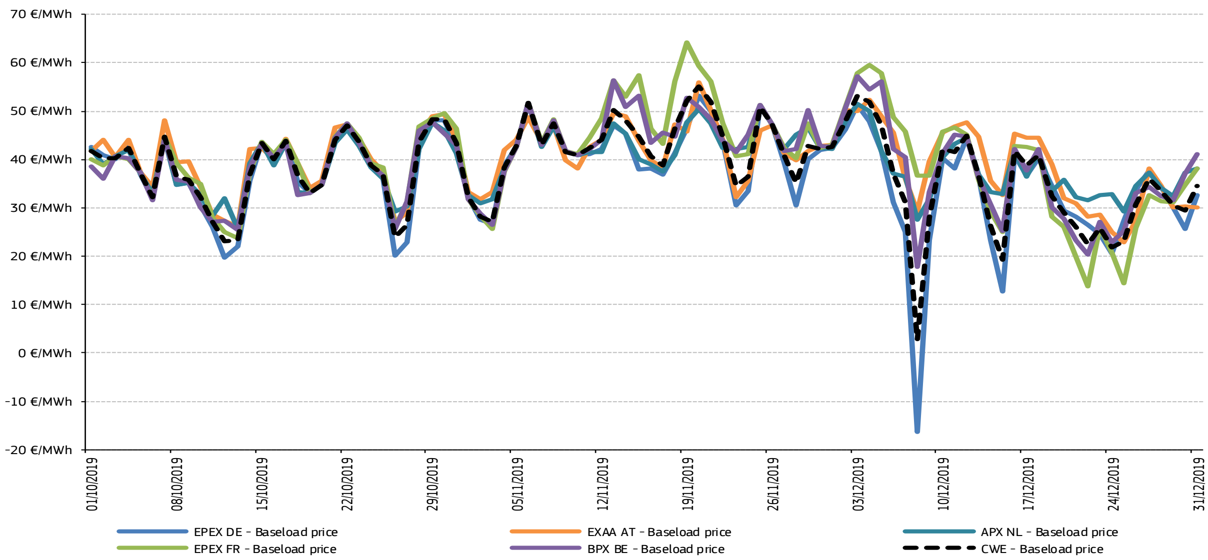


Source: Platts, EPEX. Q4 2019 volumes for EPEX-CH and EPEX-AT are missing.

- **Figure 33** shows the daily average regional day-ahead prices in the reference quarter. In the first half of Q4 2019, the daily average moved between 20 and 50 €/MWh and displayed a relatively high degree of convergence. From the middle of November, the French and (to a lesser degree) Belgian spot prices started to diverge from their German peers on the back of several cold snaps that coincided with limited availability of the French nuclear fleet suffering from maintenance overruns and unexpected outages. The combination drove the French daily average price above 64 €/MWh on November 18th, which was a ten-month high. The first cold snap of the winter pushed the total French demand to 77 GW while only 40 GW of nuclear capacity was available and 17 reactors were offline. As a result, the French coal plants returned to the market after a long period of inaction and inflows were registered from Germany, Belgium, Spain and even the UK. The pressure subsided in December thanks to increased hydro generation and low demand caused by warm weather. High variation in wind output spurred increased price divergence across the region in December.

- On the bottom side of the price spectrum, Germany saw the daily average price sinking below zero on December 8th, when wind output in the country breached 44 GW at the peak and covered more than two thirds of consumption. Hourly prices during the day were as low as -50 €/MWh.

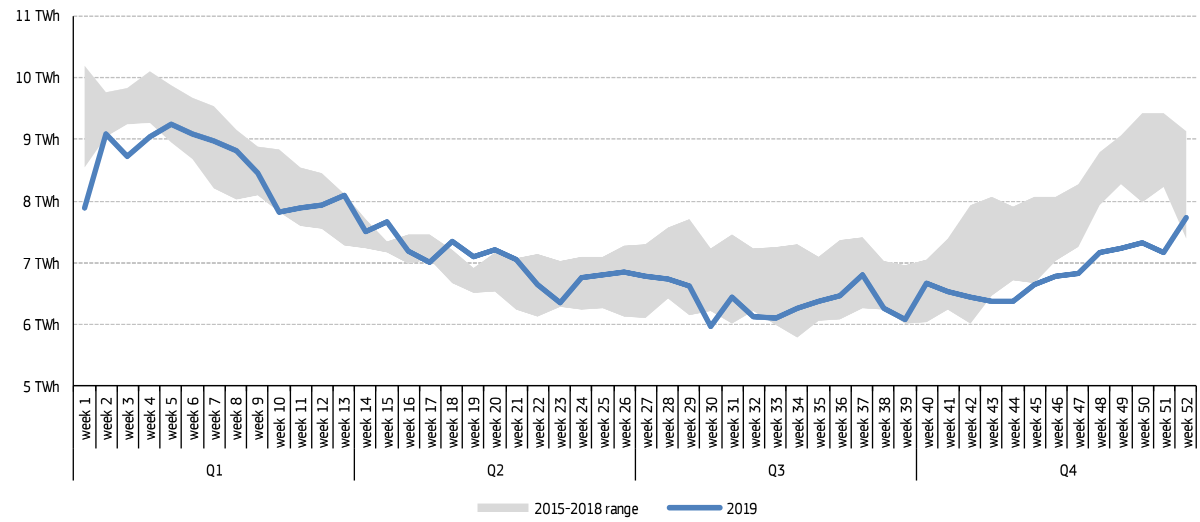
Figure 33 – Daily average power prices on the day-ahead market in the CWE region in Q4 2019



Source: Platts.

- As shown in **Figure 34,** the French nuclear fleet recorded one of its worst performances in Q4 2019 due to a flurry of outages, maintenance overruns and an earthquake in the Rhone Valley on November 14th that forced the 3.7 GW Cruas power plant to stay offline for several weeks. The total generation in the reference quarter fell by 12% year-on-year (or 12 TWh). The nuclear fleet entered 2020 with 10 units offline, while the country's TSO in its November winter outlook expected just one reactor out of service during the first week of the new year. The total annual nuclear generation, at 379 TWh, equalled the record low level from 2017. Belgium, in contrast, experienced a 167% year-on-year surge in nuclear output in Q4 2019 on the back of significantly improved availability of its fleet, which last year was operating at historically low levels due to multiple prolonged outages. Average baseload prices in the Belgian market in Q4 2019 were lower than in France, as in the previous quarter.

Figure 34 – The weekly amount of generated nuclear electricity in France



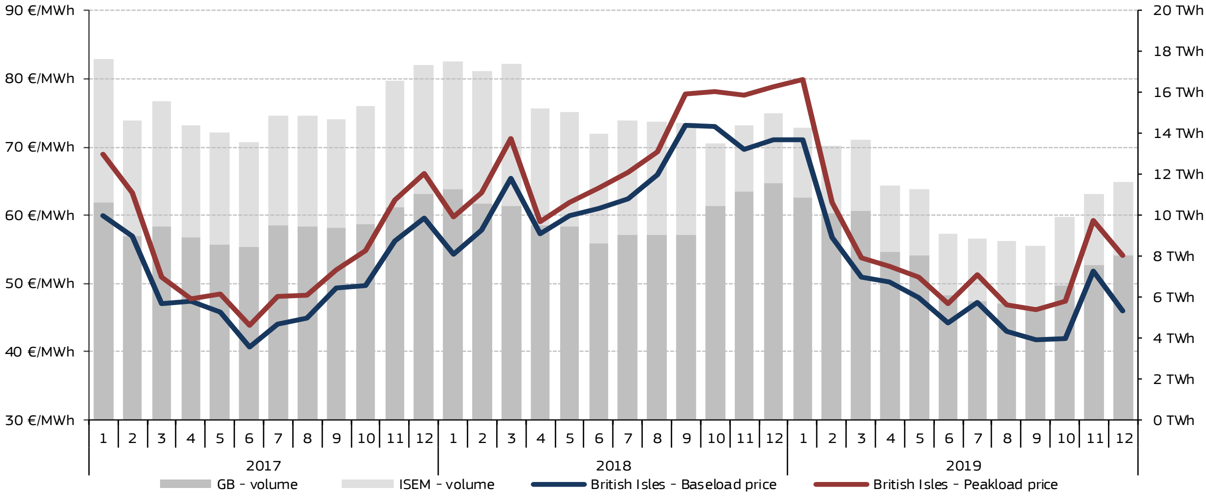
Source: ENTSO-E

5.2 British Isles (UK, Ireland)

- **Figure 35** illustrates the monthly volumes and prices on the day-ahead markets in Great Britain and in the all-island integrated market in Ireland. After starting the reference quarter at the same level as in September, average baseload and peakload prices shot up above 50 €/MWh in November due to higher gas prices, underwhelming wind output, lower-than-usual temperatures and elevated power prices across the Channel. A reversal came in December, however, as supply tensions in France eased, gas prices fell and record high wind generation pushed the average monthly price to 46 €/MWh. The peakload contract, meanwhile, widened the premium over its baseload peer from 6 to 8 €/MWh during the reference quarter, in line with past seasonal trends. Compared to Q4 2018, the average baseload price on the British Isles declined by 35% to 47 €/MWh in the reference quarter, but was up 6% against Q3 2019.

- Trading activity on the British day-ahead market recovered from summer lows. Compared to the same quarter last year, however, the traded volumes were still a third lower in Q4 2019.

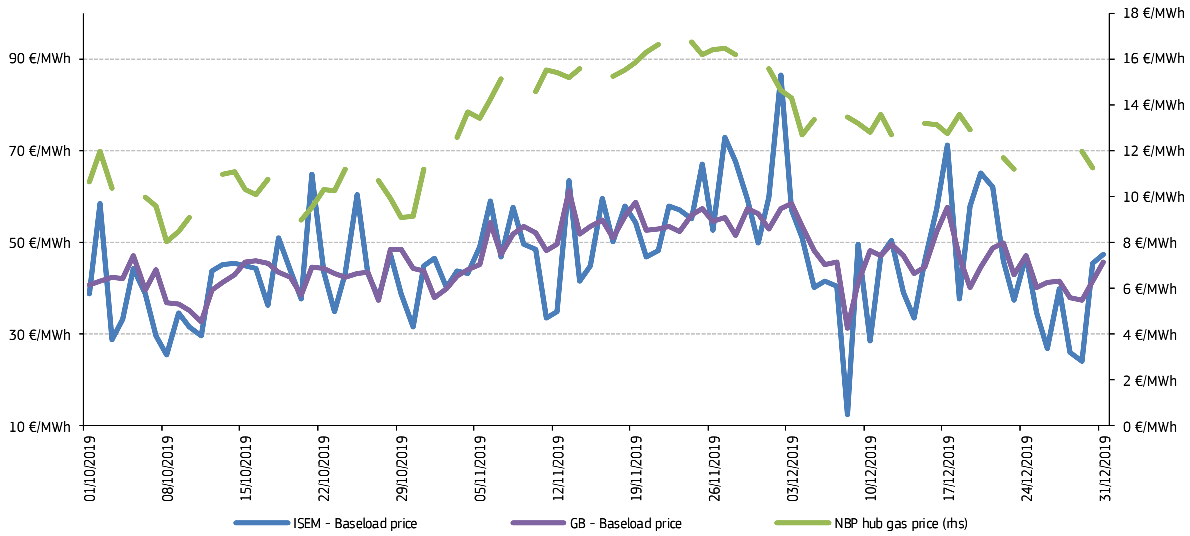
Figure 35 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Great Britain and Ireland



Source: Nord Pool N2EX, SEMO, Utility Regulator

- **Figure 36** follows the developments of daily average baseload electricity prices in Great Britain (N2EX) and Ireland (ISEM). British baseload prices hit a three-month low on October 11th amid high wind speeds and good nuclear availability. The other extreme came in the middle of November when reduced French nuclear availability and low wind output drove prices to a 10-month high. The tightness in the French market prompted all five remaining British coal power plants to return to the market after several weeks or (in some cases) months of inactivity and turned Britain into a net exporter vis-à-vis the continent. Average prices held above 50 €/MWh during the rest of the month, until they dropped suddenly at the beginning of December as wind generation picked up. They remained under 50 €/MWh for most of the rest of the year. Prices in the all-island Irish market generally followed the British contract albeit with larger volatility caused by fluctuations in wind generation, which constitutes a more important part of the power mix on the Irish island compared to Great Britain. Irish day-ahead prices went negative for a record number of hours in December (see **Figure 17**), peaking on December 8th when high wind output pushed them below zero for half of the day.

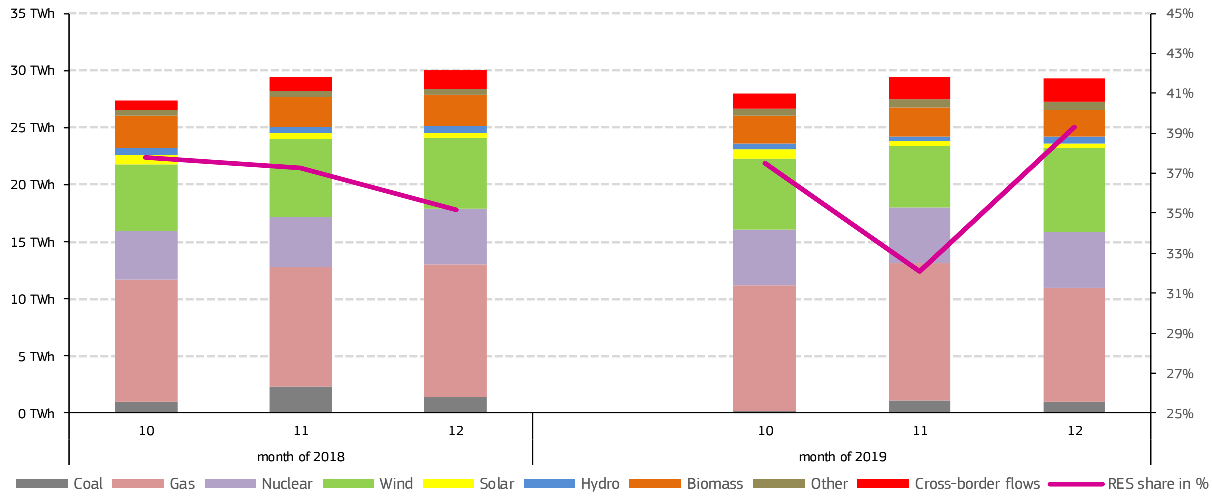
Figure 36 – Daily average electricity prices on the day-ahead market in Great Britain and Ireland



Source: Nord Pool N2EX, SEMO

- **Figure 37** compares the monthly evolution of the electricity generation mix in the UK between the reference quarter and the quarter a year before. Increased CO2 prices (higher than on the continent due to the carbon price support mechanism) and very competitive gas prices pushed coal-fired generation almost completely out of the British merit order in 2019. The small coal-firing activity reported in October and December, which took place despite deeply unfavourable margins (see **Figure 16**), was most likely the result of a need to deplete remaining fuel stocks at units destined to be retired in the following months. Roughly 4 GW of coal capacity was retired in Great Britain in 2019, leaving 7 GW of remaining capacity at five sites.
- British electricity generation recorded a slight year-on-year fall in Q4 2019, driven by a 50% slump in coal generation, rising imports and declining consumption. The share of renewable energy sources in the mix was little changed from Q4 2018 as gains in offshore wind generation (+1.3 TWh) compensated for underwhelming onshore wind output (-1.2 TWh). The combined share of gas and coal in the mix, meanwhile, declined from 44% to 42% in the reference quarter on the back of the collapse in coal generation, which fell to insignificant levels. Opportunities for coal-to-gas switching in the British market have thus been exhausted.

Figure 37 – Monthly evolution of the UK electricity generation mix in Q4 of 2018 and 2019

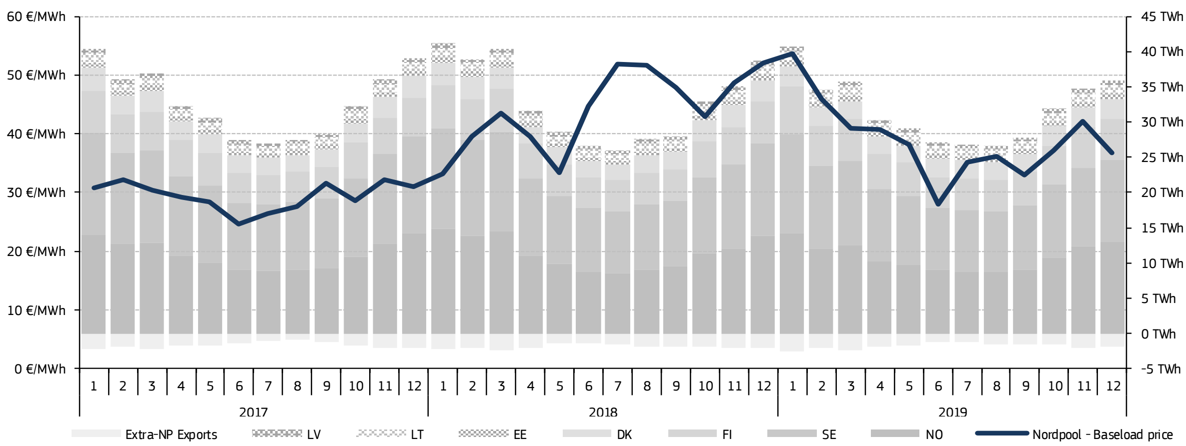


Source: ENTSO-E, Eurostat, BEIS. Positive values of cross-border flows indicate net imports. Data represent net generation.

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

- As shown in **Figure 38,** the average monthly baseload price in the Nord Pool market was heading higher in the first half of the reference period, peaking at 42 €/MWh in November amid rising gas prices and colder and less windy weather conditions in Sweden and Norway. Afterwards, the overall tightness in the regional generation-consumption balance eased thanks to warmer temperatures and higher wind speeds, which compensated for a relatively low water reservoir level and allowed the system average to settle below 37 €/MWh in the final month of the year. Compared to Q4 2018, the average system baseload price declined by 19% to 39 €/MWh in the reference quarter.

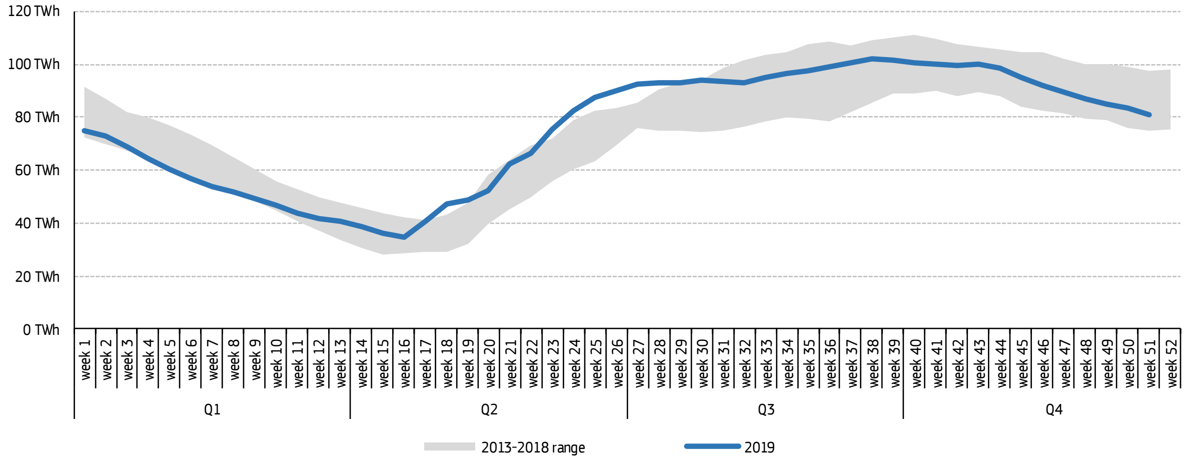
Figure 38 – Monthly electricity exchange traded volumes and the average day-ahead wholesale prices in Northern Europe



Source: Nord Pool spot market

- **Figure 39** 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. Hydro stocks in the region started the reference quarter at an average level. But while they held steady in October, the need to compensate for lower wind generation and increased demand spurred by lower temperatures depleted the reservoirs considerably in November. The falling trend continued in December despite increased wind generation, as precipitation levels remained below average and Sweden kept its hydro output high for export purposes. The total hydro generation in the region decreased by 1.2 TWh year-on-year in Q4 2019 due to a large drop in Norwegian output (-4.0 TWh) that was only partially compensated by increased Swedish generation (+2.6 TWh).

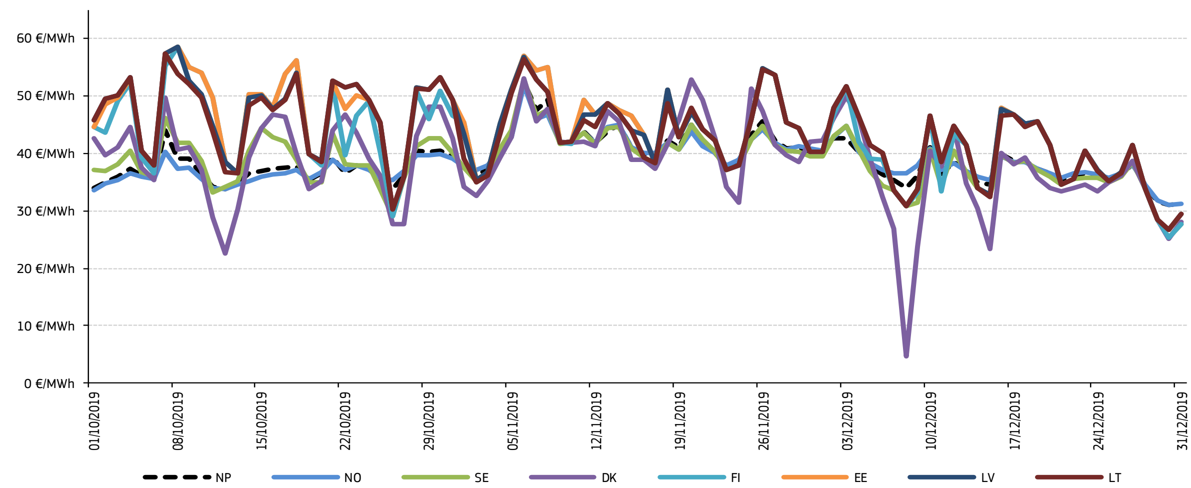
Figure 39 – Nordic hydro reservoir levels in 2019, compared to the range of 2013-2018



Source: Nord Pool spot market

- **Figure 40** shows that average daily prices across Northern Europe in Q4 2019 continued to display a high degree of divergence in Q4 2019, as in previous quarters. The Baltic region and Finland, which both suffered from considerable deficits throughout the reference quarter (see **Figure 21** and **Figure 22**), registered nearly permanent premiums over the system contract. In November and December, however, these occasionally reverted into discounts due to low demand during weekends and Christmas holidays. Daily prices in Denmark displayed the highest volatility due to growing wind penetration in country's power mix, which reached 56% in windy December. Record high wind generation also brought average Danish prices below the system level contract in the final month of the year. Norway reported daily baseload prices at or below the system price level in the first two months of the reference quarter, but entered into premium territory in December due to curtailed hydro generation. There was one significant price dip driven by a wind generation surge in Denmark and Germany in December (described in greater detail in **Figure 17**).
- Contributing to the net importer position of Finland and the Baltics were flows from the Russian and Belarusian zones, which reached 4 TWh (on a net basis) in Q4 2019, unchanged compared to the same quarter last year.

Figure 40 – Daily average regional prices and the system price on the day-ahead market in the Nordic region

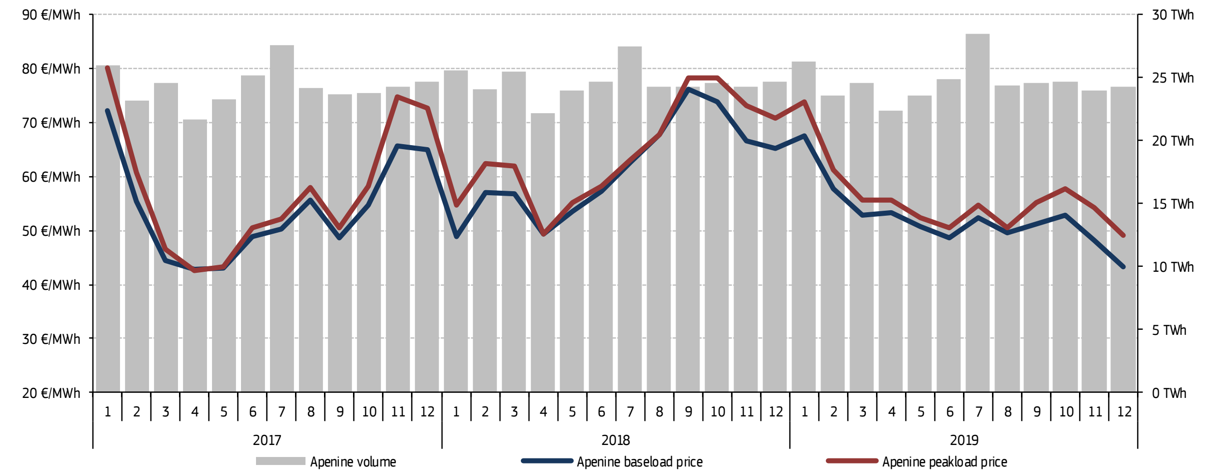


Source: Nord Pool spot market

5.4 Apennine Peninsula (Italy, Malta)

- Italian monthly average baseload electricity prices (**Figure 41**) were on a declining trajectory during most of the reference quarter. The drivers were increased wind generation in the south and high hydro output in the north in November and December, generally mild weather conditions and falling consumption. The average baseload price in the reference quarter decreased by 5% compared to Q3 2019 to 48 €/MWh and was down 30% year-on-year. Meanwhile, the peakload electricity contract widened the premium over its baseload peer to 5-6 €/MWh, in line with usual seasonal developments.

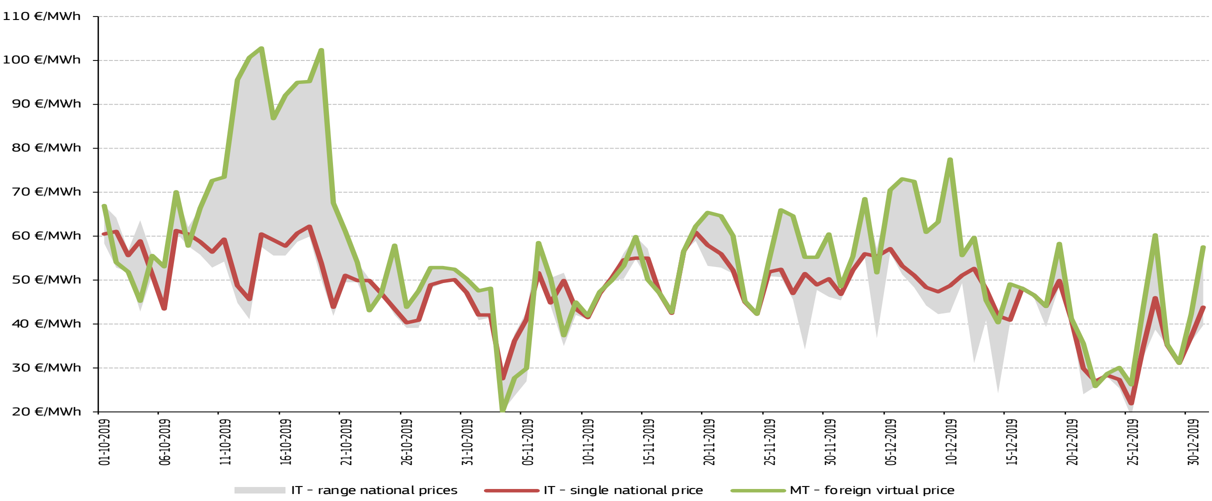
Figure 41 – Monthly electricity exchange traded volumes and average day-ahead wholesale prices in Italy



Source: GME (IPEX)

- **Figure 42** shows the daily evolution of the national average price and the range of the regional price areas in the Italian market. The fourth quarter of 2019 was a relatively calm period of muted volatility, with several price dips caused by wind generation surges or low holiday demand during Christmas time.
- 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 (especially the Sicilian price zone) influence the Maltese wholesale electricity market. As visible in **Figure 42**, prices in the Maltese zone mostly followed the Italian average during Q4 2019. Price spikes in October were caused by cable outages in Sicily and reduced flows from the mainland. Malta suffered several nation-wide blackouts in November and December that severely affected its households and businesses. The cause was a damaged undersea cable linking the island to Sicily, which enables imports of cheaper electricity. Malta has enough domestic capacity to meet its demand but activating it when the connector fails takes several hours.

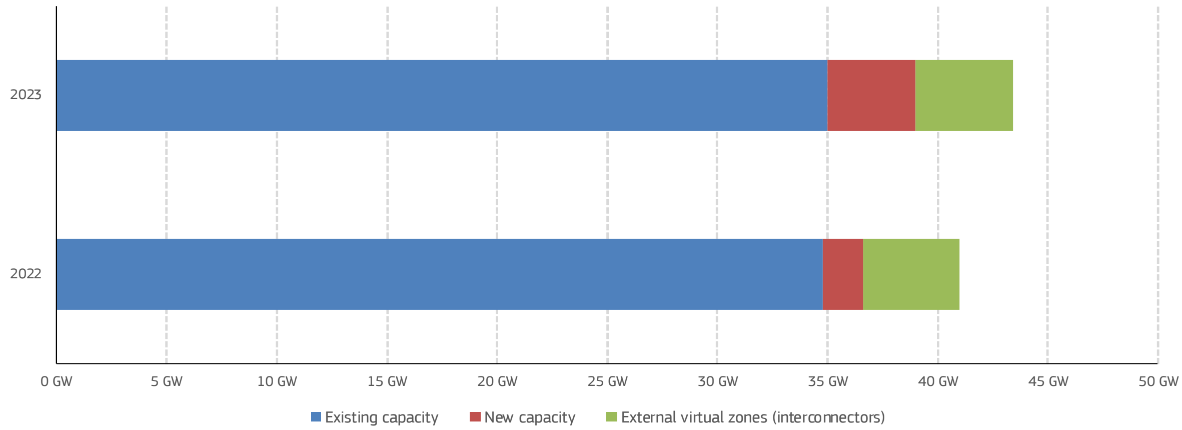
Figure 42 – Daily average electricity prices in the Italian day-ahead market, within the range of different area prices



Source: GME (IPEX)

- **Figure 43** informs about the first two auctions of the recently established Italian capacity market, which took place in November and resulted in 40.9 GW of capacity contracted for delivery in 2022 and 43.4 GW of capacity contracted for delivery in 2023. Both auctions saw prices hitting a preset cap of 33,000 €/MW/year for existing and 75,000 €/MW/year for new power plants or other types of capacity providers. Apart from domestic awards, 4.4 GW was also contracted from external virtual zones via existing interconnectors at prices ranging from 3,500 to 5,000 €/MW/year. The 2023 auction, which provided participants more time for constructing new projects, bought 4 GW of new capacity with 15-year contracts, of which 2.6 GW were combined cycle gas plants (CCGT), 0.9 GW were open cycle gas plants, 0.4 GW were other thermal plants and 80 MW were batteries. Two thirds of the newly contracted capacity will be located in the North zone, the industrial heart of the country.
- The total annual cost of the capacity mechanism was estimated by the Italian TSO at €1.5 billion per year. This compares with €1.2 billion of gross costs of the UK capacity mechanism projected for 2019. The Italian auction prices compare favourably with the average price of 60,000 €/MW/year reached in the fourth Polish capacity auction in December 2019. Italy's reserve margin has decreased considerably in the past two decades, with around 20 GW of thermal capacity retiring since 2012. This has exposed the northern regions of the country, where many large consumption centres are concentrated, to a greater risk of power outages.

Figure 43 – Results of the first two Italian capacity auctions by delivery year

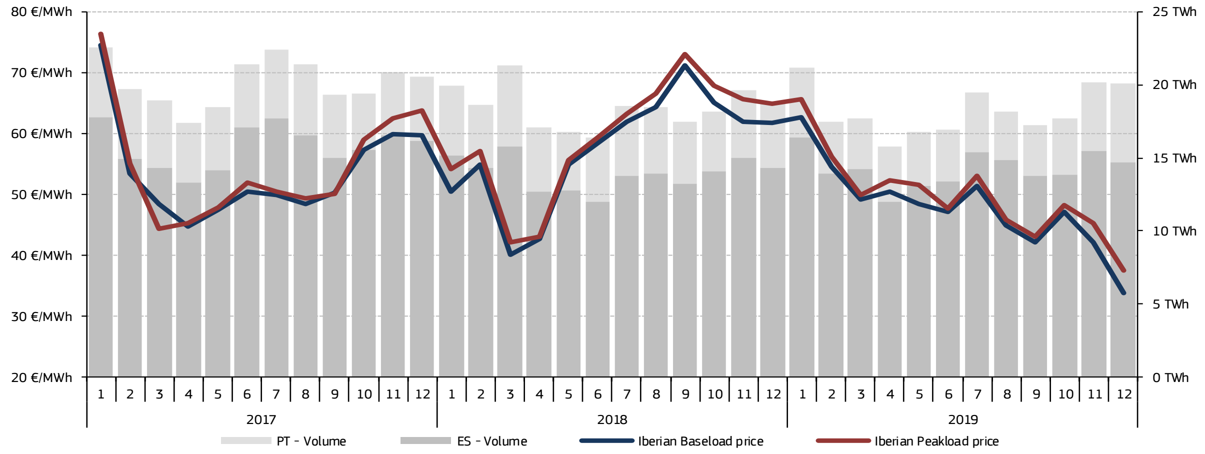


Source: Terna, Platts

5.5 Iberian Peninsula (Spain and Portugal)

- **Figure 44** reports on the monthly average wholesale baseload and peakload contracts in Spain and Portugal. The region went through a development similar to Italy, if more extreme in both ways. The average baseload price in October went up 12% month-on-month to 47 €/MW on the back of low wind and hydro generation. However, a massive surge in wind output and recovering hydro generation pushed prices lower in November, despite limited nuclear availability in Spain. The falling trend continued in December thanks to weakening demand, strong winds and high precipitation that brought hydro power generation to levels last seen in the spring of 2018. This combination caused the December average for baseload to land under 34 €/MWh, a three-year low. Compared to Q4 2018, the average baseload price declined by 35% to 41 €/MWh in the reference quarter. Compared to the previous quarter, the average baseload contract was down 11% in Q4 2019.

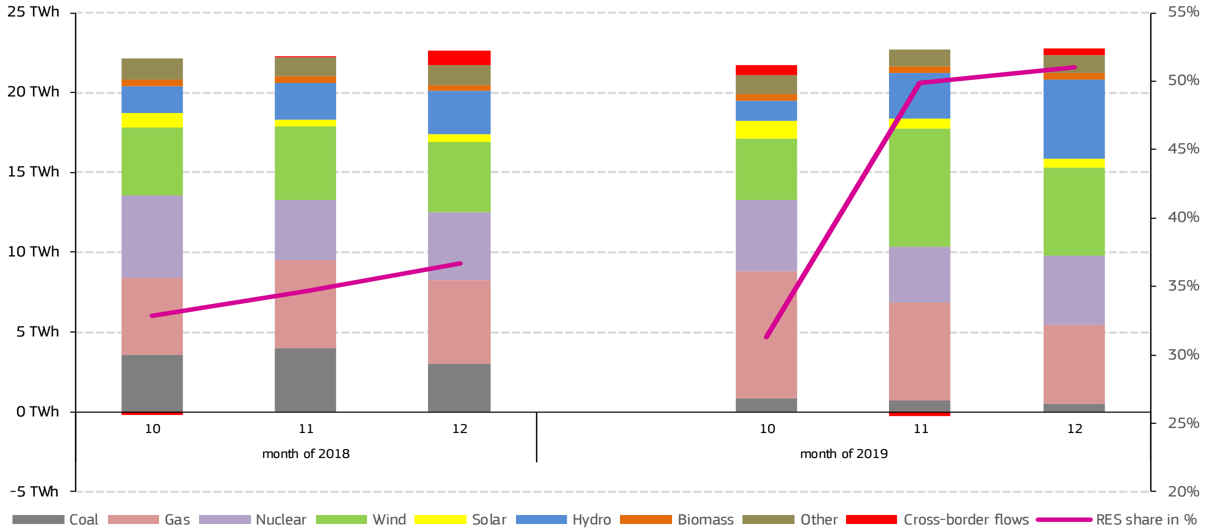
Figure 44 – Monthly electricity exchange traded volumes and average day-ahead prices in the Iberian Peninsula



Source: Platts, OMEL, DGEG

- **Figure 45** displays the evolution of the monthly electricity generation mix in Spain during the fourth quarter of 2019, as well as during the same period of the previous year. Thanks to more than 7 GW of newly installed wind and solar capacity in 2019 and favourable weather conditions, the Spanish share of renewable electricity sources (hydro, wind, solar and biomass) reached 44% on average in the reference quarter, up from 35% a year before. Wind energy alone expanded its presence in the mix to 25% in Q4 2019, compared to 20% a year earlier.
- The combined share of coal and gas in the mix shrank from 39% in Q4 2018 to 32% in Q4 2019, as increased renewable generation and falling demand left smaller space for thermal plants. Intensive coal-to-gas switching reduced coal's share of the total volume of generated electricity to negligible levels, while helping gas expand its presence to 29% of the mix (from 20% a year ago). In December, the country experienced its first days with coal capacities shut out of the market altogether. Several retirements of coal power plants were brought forward. The share of nuclear energy in Spain's mix, at 19%, was a percentage point lower compared to Q4 2018. The total generation in the reference quarter remained unchanged year-on-year.

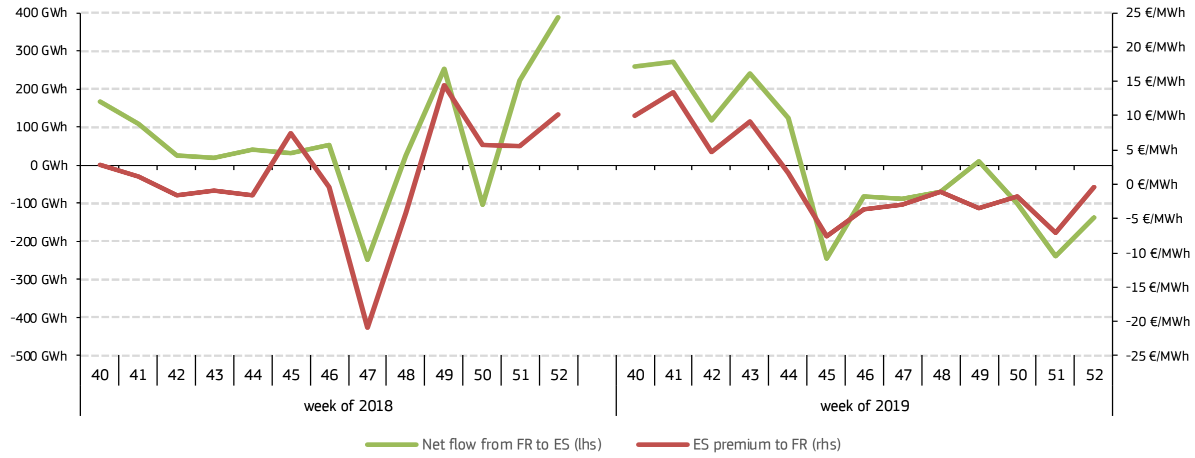
Figure 45 – Monthly evolution of the electricity generation mix in Spain in Q4 of 2018 and 2019



Source: ENTSO-E, Eurostat. Negative value of cross-border flows indicates net exports. Data represent net generation.

- **Figure 46** shows weekly electricity flows between France and Spain and price differentials between the two bidding zones. Due to significantly reduced availability of the French nuclear capacities and high Spanish wind and hydro output, Spanish baseload prices were consistently lower than their French peers in November and December. Cross-border electricity flows generally followed price differentials, adding up to roughly a net zero balance (although slightly tilted in France's favour). Spain and France are connected through five high-voltage power lines of combined 2.8 GW capacity.
- Bilateral trade with Morocco in Q4 2019 resulted in net imports of 80 GWh to Spain.

Figure 46 – Weekly flows between France and Spain and price differentials between them

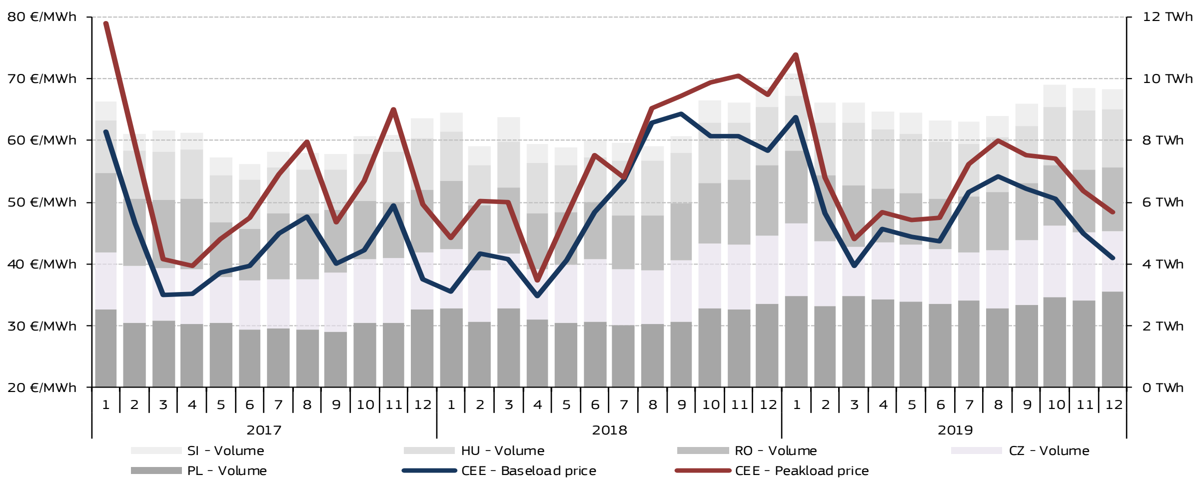


Source: ENTSO-E, OMEL, Platts

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

- **Figure 47** shows that average monthly prices for baseload power in Central Eastern Europe in Q4 2019 remained on their downward trajectory that began in August. The average baseload contract in the region went from 51 €/MWh in October to 45 €/MWh in November to 41 €/MWh in December, pushed down by elevated wind generation in Poland, falling demand spurred by unusually warm temperatures (see **Figure 2**) and a very good performance of the regional nuclear capacities. The premium of peakload monthly averages over their baseload peers widened to 7.5 €/MWh at the end of the reference quarter. In relative terms, the difference was the highest since June 2018. When compared to the previous Q4, the average baseload price in the reference quarter fell by 24% to 45 €/MWh. Compared to Q3 2019, the average price in the reference quarter decreased by 14%.
- Relatively high carbon prices continued to put a strain on the regional lignite and coal power plants, forcing the region to import 2.7 TWh of electricity in the reference quarter on a net basis, up from 0.9 TWh a year earlier. Poland alone increased its net imports from 1 TWh in Q4 2018 to 3 TWh in Q4 2019. Germany, Austria, Nord Pool markets and Ukraine were the largest sources of inflows into the region.

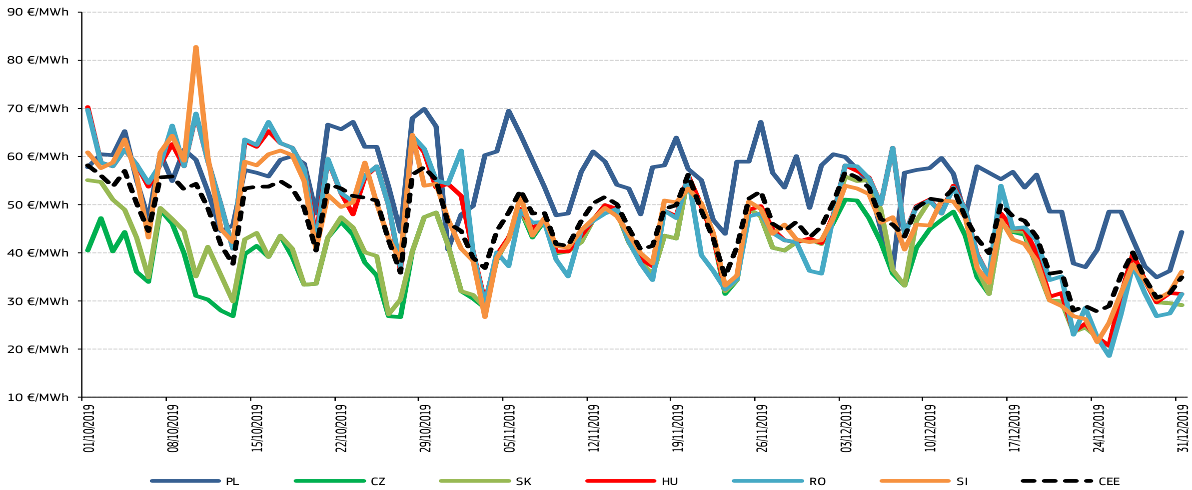
Figure 47 – Monthly electricity exchange traded volumes and average day-ahead prices in Central Eastern Europe (CEE)



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

- **Figure 48** shows that in October, high volatility and wide differences in daily average baseload prices persisted on the day-ahead market across the CEE region. The lowest prices, usually between 30 and 50 €/MWh, were reported in Czechia, the regional export powerhouse, and its well-connected neighbour Slovakia. Baseload contracts in Poland, Hungary, Romania and Slovenia, which all had to rely on imports to some extent, were on average sold at a 20 €/MWh premium to the Czech quotes. In the middle of the month, Hungary and Romania displayed the highest prices as maintenance on an interconnector with Slovakia reduced cheap imports from Germany and Czechia and as low wind and thermal generation stressed the supply-demand balance in Romania. One week later, the Polish market took over the baton due to reduced import capacity from Czechia and Germany. Prices converged more during November and December as infrastructure issues receded and increased wind speeds and precipitation in the Balkans improved renewable generation levels and helped with occasional supply pressures. Only Poland retained its usual premium over the rest of the region. Prices fell considerably before and during Christmas holidays on the back of low demand and warm weather conditions.

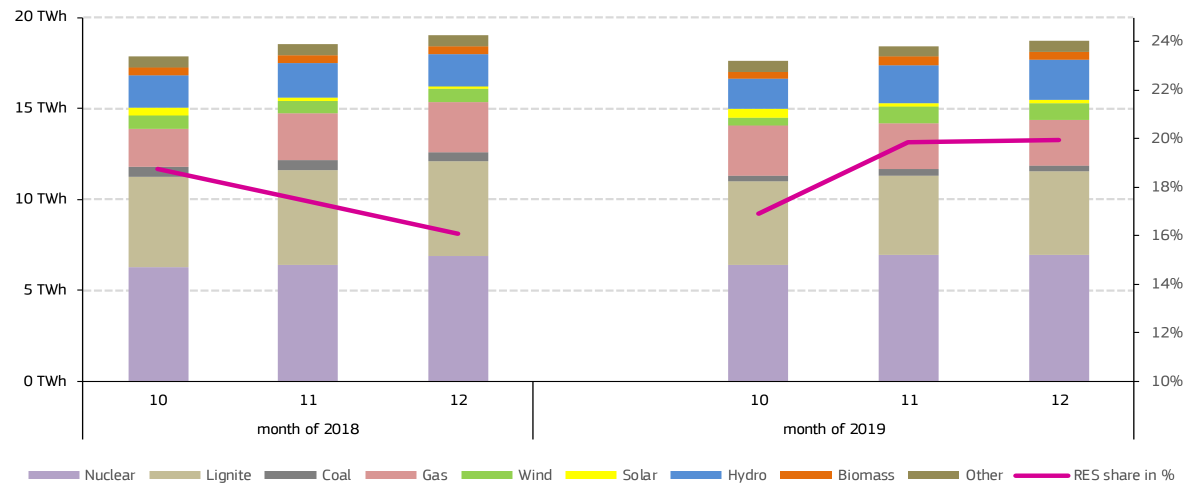
Figure 48 – Daily average power prices on the day-ahead market in the CEE region



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

- **Figure 49** compares the monthly evolution of the combined electricity generation mix of in the CEE region (excluding Poland) between the reference quarter and the quarter a year before. Thanks to good availability, nuclear generation increased its share of the mix to 37% in Q4 2019, up from 35% a year before. The reduced competitiveness of coal generation due to still relatively high CO2 prices caused the combined share of lignite and coal in the reference quarter to fall from 31% to 26% year-on-year, while gas managed to increase its share only slightly – from 13% to 14% year-on-year – as the gap left by coal was mostly filled with increased nuclear and hydro generation. Renewable energy sources (wind, solar, hydro and biomass) accounted for 19% of the total electricity production in the reference quarter, up from 17% in Q4 2018 on the back of improved hydro generation in Slovakia and Slovenia. In Poland, which is analysed separately due to significant differences in the size and structure of its generation base, the combined share coal and lignite in its mix went down measurably to 71% in the reference quarter (compared to 77% in Q4 2018), while renewables increased their share from 15% to 17% year-on-year thanks to higher wind generation. Gas increased its share in the mix from 7% to 11% year-on-year, demonstrating some coal-to-gas switching potential in the country. However, most of the ground ceded by coal was taken by increased imports.

Figure 49 – Monthly evolution of the electricity generation mix in the CEE region (excluding Poland) in Q4 of 2018 and 2019

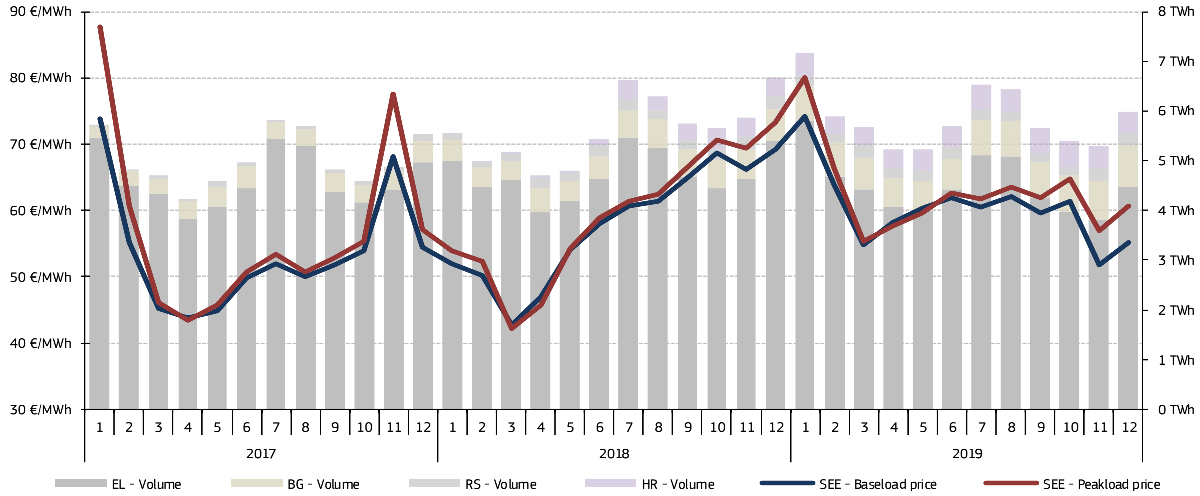


Source: ENTSO-E.

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

- **Figure 50** shows that the trade-weighted monthly average baseload prices in the SEE region went through a volatile quarter in Q4 2019, driven mainly by evolving conditions in Greece (by far the most liquid market). In October, the supply-demand balance tightened slightly amid dry and calm weather curbing Balkan hydro and wind generation. But the situation improved markedly in November when better availability of nuclear capacities in Bulgaria, higher flows in Balkan rivers and a sharp temperature-driven demand drop in Greece pushed the regional monthly average to 52 €/MWh, the lowest level since April 2018. December witnessed tighter conditions in Bulgaria and Greece that drove the regional average to 55 €/MWh. Peakload contracts, meanwhile, traded at an increasing premium over their baseload peers, reaching almost 6 €/MWh at the end of the year, which was in line with past seasonal patterns.

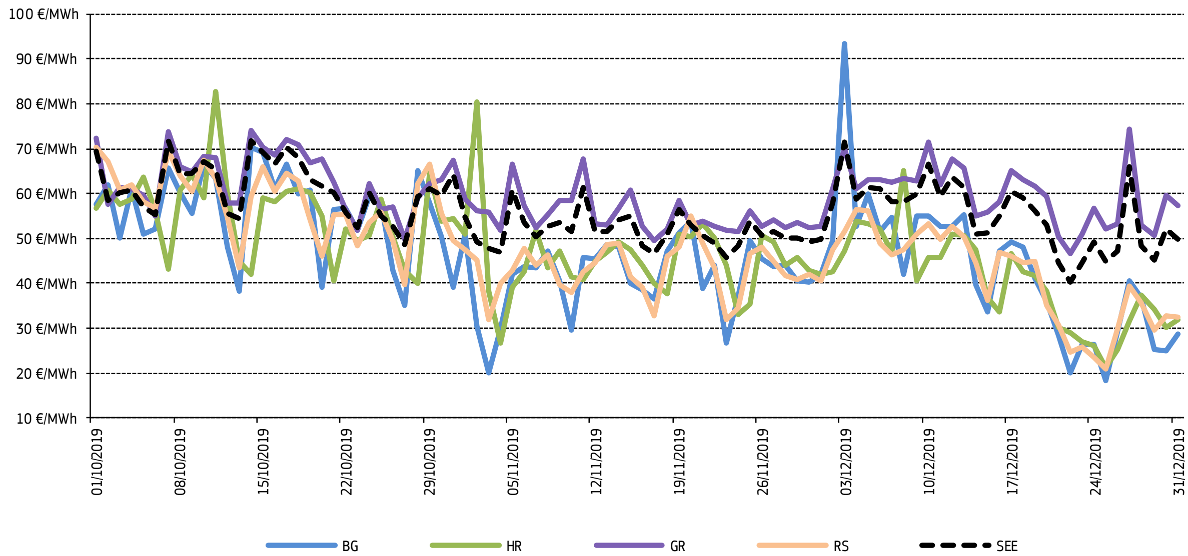
Figure 50 – Monthly traded volumes and baseload prices in South-Eastern Europe (SEE)



Source: IBEX, LAGIE, OPCOM, SEEPEX

- Apart from Greece, daily baseload price movements in individual markets were relatively well synchronized during Q4 2019, as shown in **Figure 51**. Prices in Croatia and Serbia were generally on a downward trajectory thanks to gradually improving hydro conditions. Bulgaria witnessed a sharp year-on-year drop in demand in the reference quarter (-5%) on the back of a very warm start of the heating season, but this was compensated by the reduced competitiveness of its lignite fleet facing higher carbon costs and a 40% slump in hydro generation. As a result, Bulgaria recorded the lowest year-on-year fall (-10%) in the average baseload price for the whole Q4 2019 within the region. In Croatia and Serbia, the quarterly average fell by 26% year-on-year, while in Greece it declined by 16%.

Figure 51 – Daily average power prices on the day-ahead market in Bulgaria, Croatia, Greece and Serbia



Source: IBEX, LAGIE, SEEPEX, CROPEX

6 Retail markets

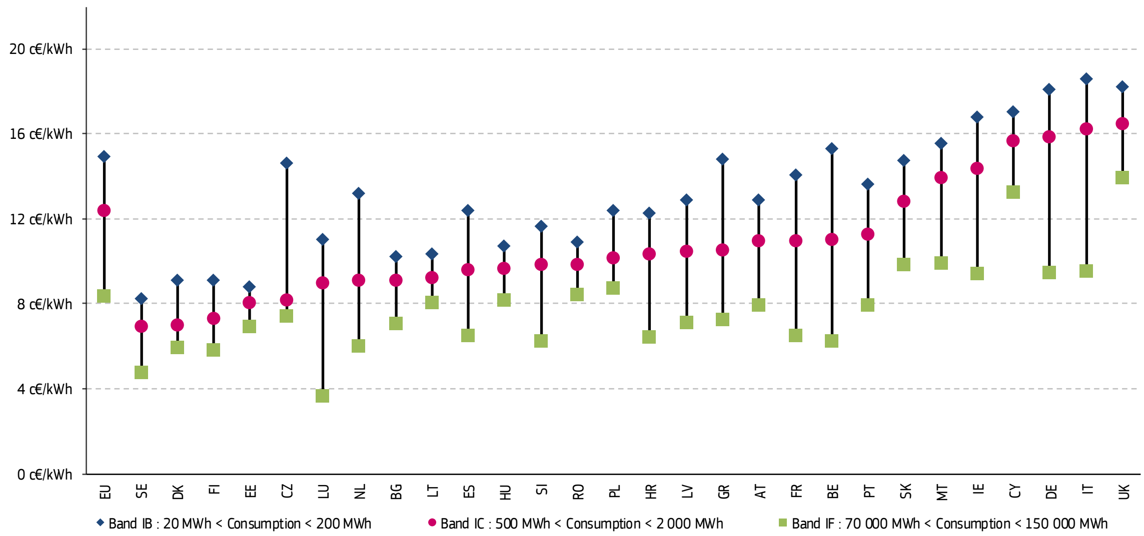
6.1 Retail electricity markets in the EU

- **Figures 52 and 53** display the estimated retail prices in December 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 consumed).

- Smaller industrial consumers (band IB) were assessed to pay the highest prices in the Italy (18.6 c€/kWh), the UK (18.2 c€/kWh) and Germany (18.1 c€/kWh), followed by Cyprus and Ireland (17.0 and 16.8 c€/kWh, respectively). The lowest prices in the same category were assessed to be in Sweden (8.1 c€/kWh) and Estonia (8.8 c€/kWh). The ratio of the largest to smallest reported price was above 2:1. On the other side of the consumer spectrum, industrial companies with large annual consumption (IF), including most energy-intensive users, paid the highest prices in the UK (13.9 c€/kWh) followed by Cyprus (13.3 c€/kWh), Slovakia and Malta (both 9.9 c€/kWh). Luxembourg (3.7 c€/kWh) was assumed to have the lowest prices, followed by Sweden and Finland. The ratio of the highest to lowest price for large industrial consumers was almost 4:1 for this consumer type. Compared to December 2018, the average assessed EU retail electricity price for the IF band increased by 7% to 8.4 c€/kWh.

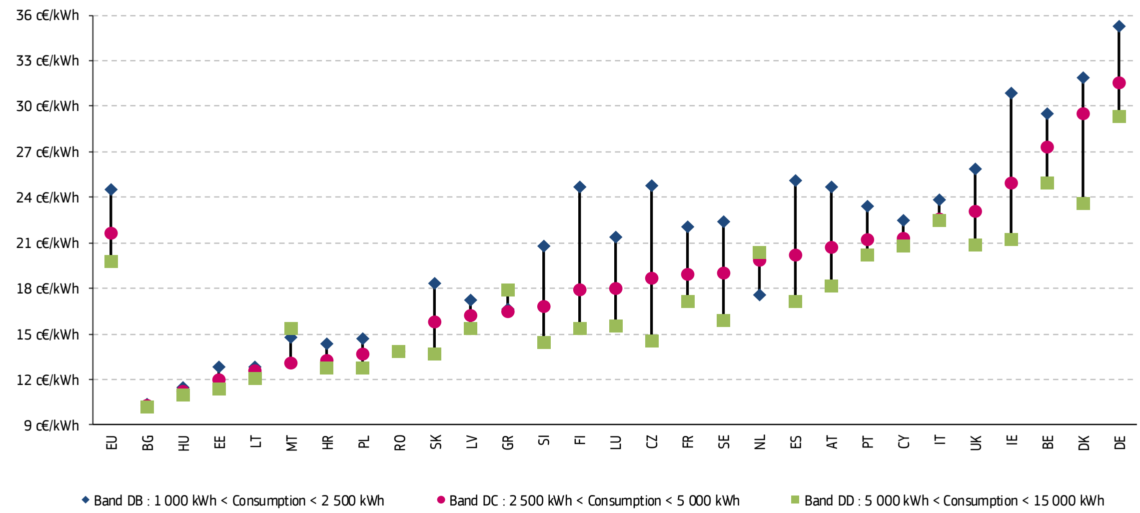
- In December 2019, Germany (29.3 c€/kWh) was assessed as having the highest electricity price for large household consumers (band DD), followed by Belgium (24.9 c€/kWh), and with Denmark (23.6 c€/kWh) in the third place. The lowest price for big households was calculated for Bulgaria (10.2 c€/kWh) and Hungary (10.9 c€/kWh). In the case of small households, Germany was again evaluated as having the highest price (35.2 c€/kWh), followed by Denmark and Ireland, while Bulgaria and Hungary found themselves again on the other side of the price spectrum. 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 relatively high, around 3:1.

Figure 52 – Industrial electricity prices, December 2019 – without VAT and recoverable taxes



Source: Eurostat, DG ENER

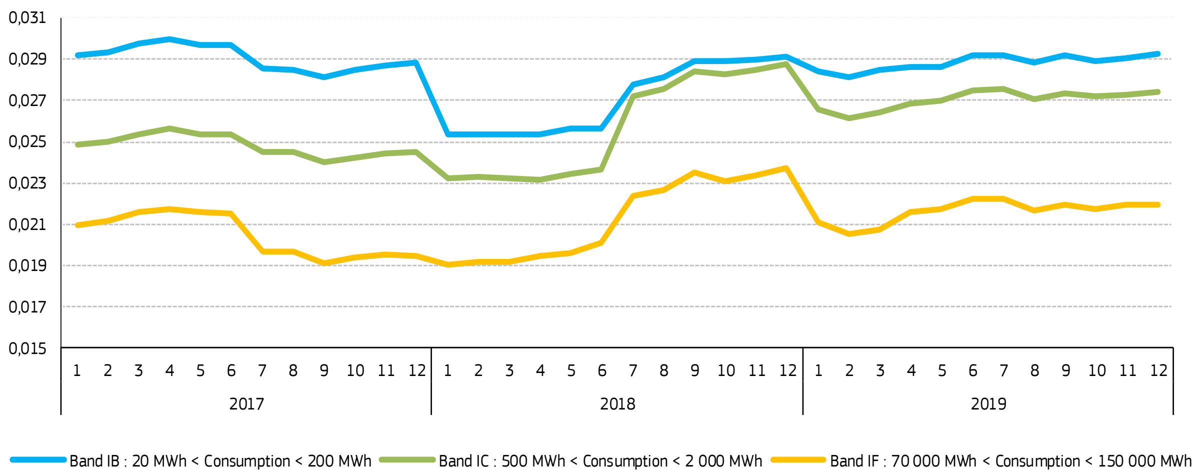
Figure 53 – Household electricity prices, December 2019 – all taxes included



Source: Eurostat, DG ENER

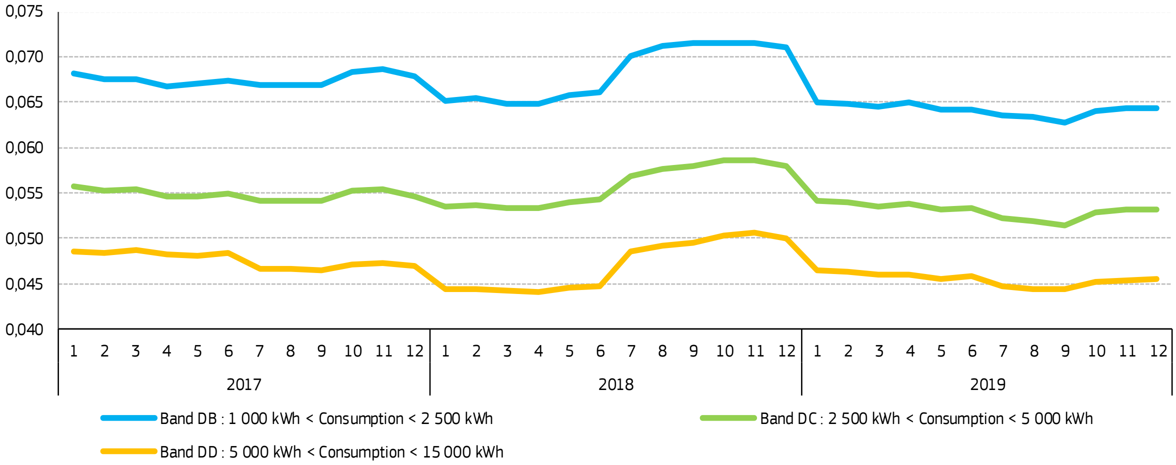
- **Figures 54 and 55** display the convergence of retail prices across the EU28 over time, by depicting their standard deviation. End-user prices for smaller and medium-sized businesses showed slightly rising levels of price divergence throughout the reference quarter in comparison to Q3 2019, while in the case of large industrial consumers, the deviation was little changed from the previous quarter. 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 consumption.
- In the case of households, the trend of growing convergence of retail electricity prices in all consumption categories which started at the beginning of 2019 was halted and partly reversed in the reference quarter. This could be explained by the fact that countries with relatively higher prices experienced increases, while those at the bottom of the price spectrum stayed largely at unchanged levels. Household prices tend to be more impacted by regulated elements (network charges, taxes and levies) so their variation across Member States is greater than in the case of industrial consumers.

Figure 54 – Standard deviation of retail electricity prices in the EU28 for industrial consumers



Source: Eurostat, DG ENER

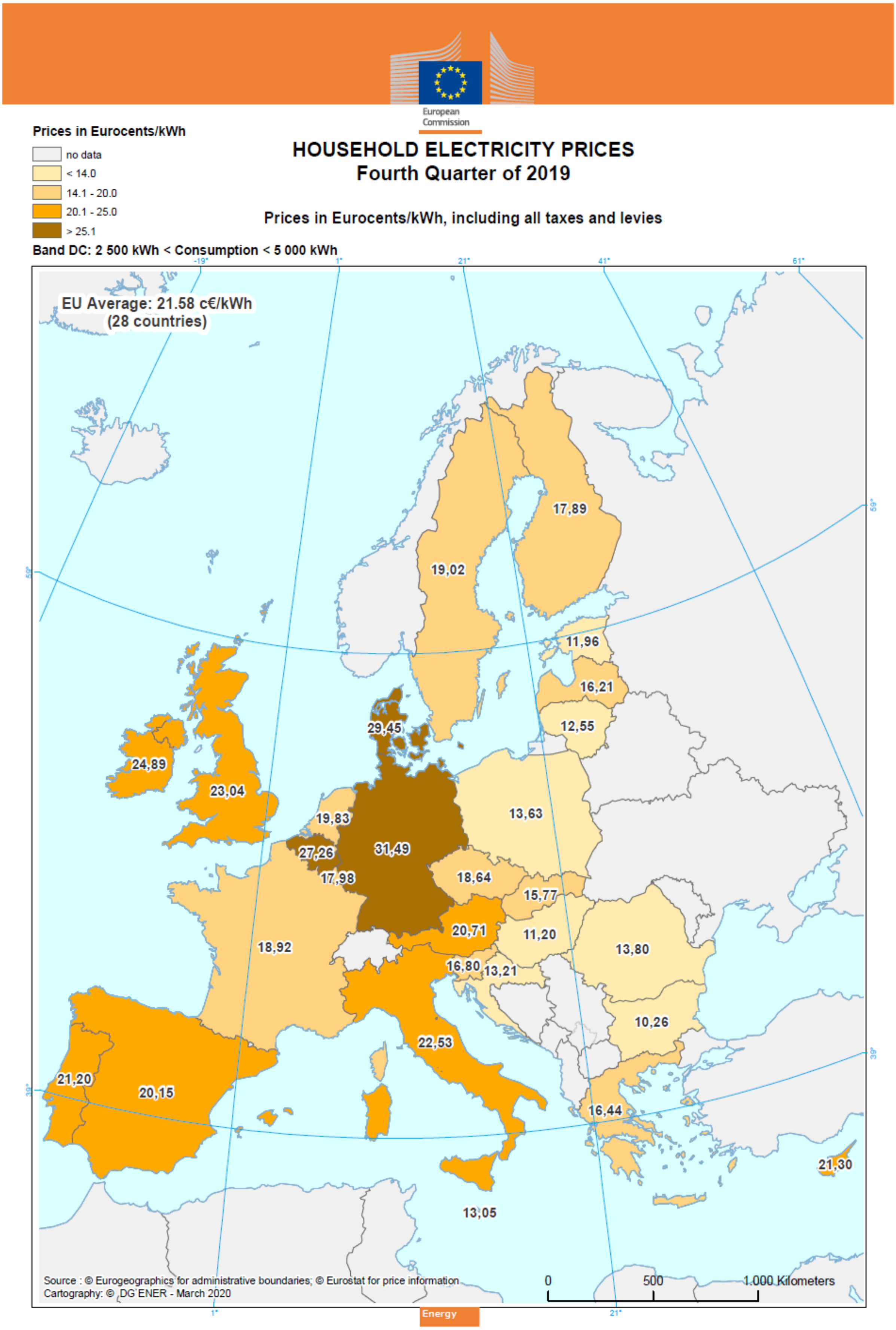
Figure 55 – Standard deviation of retail electricity prices in the EU28 for household consumers



Source: Eurostat, DG ENER

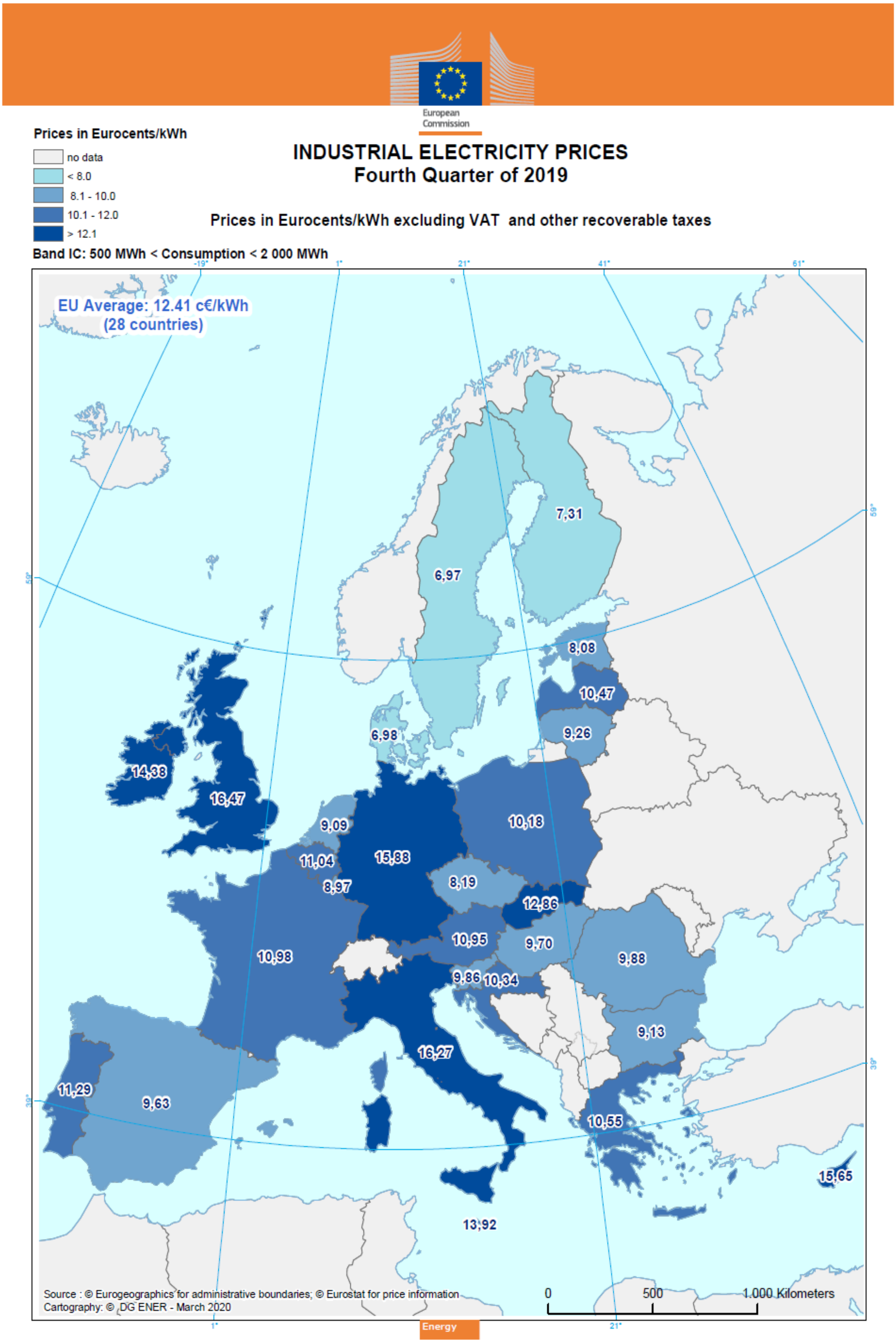
- **Figures 56 and 57** display the estimated electricity prices paid by EU households and industrial customers with medium level of annual electricity consumption in the last month of Q4 2019. In the case of household prices, Germany topped the list, followed by Denmark and Belgium. As was the case in previous quarters, Bulgaria retained its position as the country with the cheapest household electricity prices, with Hungary assessed to be in the second place. The average price for the EU28 climbed up 1% in the reference quarter compared to December 2018. The largest year-on-year increases in the household category were assessed in Czechia (+17%), followed by the Netherlands and Lithuania (both +14%). The biggest year-on-year falls were estimated for Spain (-18%) and Estonia (-16%).
- In the case of mid-sized industrial consumers, Sweden was assessed to have the most competitive price in Q4 2019, moving in front of Denmark and with Finland taking the third place. Meanwhile, the UK, Italy and Germany stood at the other end of the spectrum. The average retail price for industrial customers in the EU in the reference period, at 12.41 eurocents/kWh, rose by 7% compared to Q4 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 56 – Household Electricity Prices, fourth quarter of 2019



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

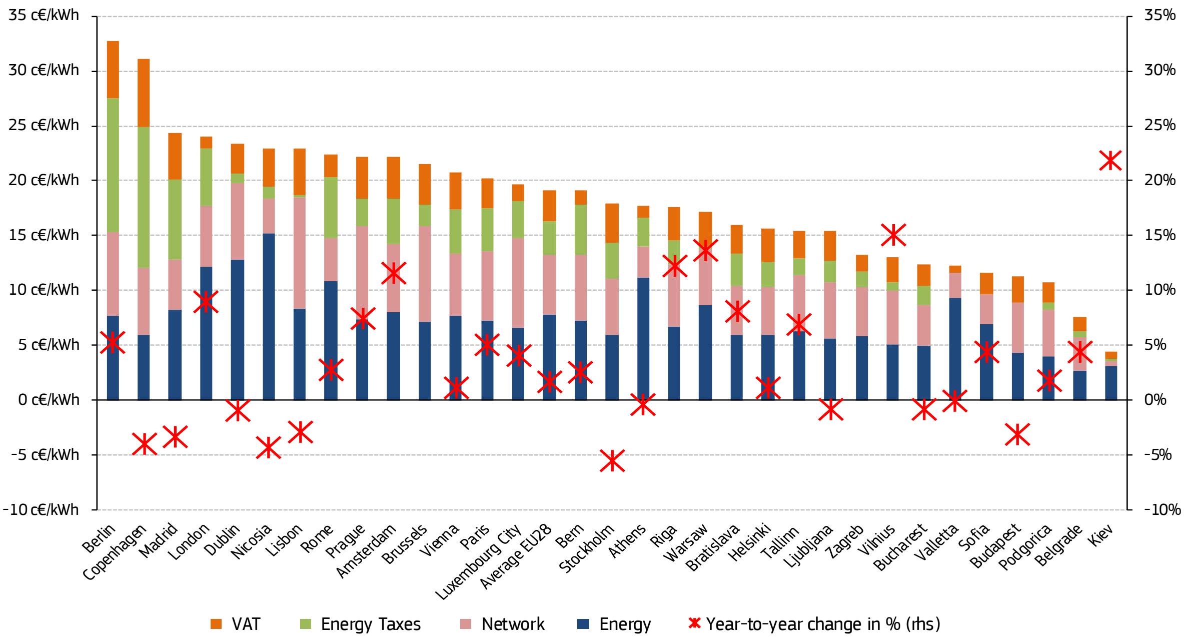
Figure 57 – Industrial Electricity Prices, fourth quarter of 2019



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

- **Figure 58** 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 December 2019, the highest prices were observed in Berlin and Copenhagen (32.7 and 31.1 c€/kWh, respectively) where energy taxes accounted for approximately a third of the final bill. The lowest prices of EU28 Member States were recorded in Budapest and Sofia (11.3 c€/kWh and 11.6 c€/kWh, respectively). This corresponds to the Eurostat data analysed in **Figure 53**. Non-Member States in Europe's east tend to have lower prices. Thus, electricity for an average household in Kiev is seven times cheaper than for one in Berlin.
- The highest levels of the energy component were reported from Nicosia, Dublin and London (12-15 c€/kWh), cities surrounded by wholesale markets with higher prices compared to the EU average. The lowest levels of the energy component (4.5-6 c€/kWh) were recorded in the capitals of countries with stronger forms of price regulation (Budapest, Bucharest, Bratislava) or with a high degree of renewable production (Copenhagen, Stockholm). The EU28 average for the energy component was 7.8 c€/kWh (up 4% from December 2018). Thus, the general decrease in European wholesale prices witnessed during 2019 has not been fully passed through to retail prices yet. This could be explained by the fact that retailers usually buy electricity in advance before it is sold to customers, which results in a time lag between developments in wholesale and retail markets.
- The highest network charges were recorded in Lisbon (10.2 c€/kWh) where, despite a significant cut in 2019, they accounted for 45% of the total price and were measurably higher than the energy component. The lowest network fees were collected in Valletta (1.6 c€/kWh) and Sofia (2.7 c€/kWh). The EU average in the reference quarter was 5.3 c€/kWh (down 1% from December 2018).
- Apart from Berlin and Copenhagen (10-11 c€/kWh), the highest energy taxes were paid by households in Madrid and Rome (5.5-7.5 c€/kWh). Valletta, Sofia and Budapest stood at the other end of the range, with zero energy taxes collected by the local authorities.

Figure 58 – The Household Energy Price Index (HEPI) in European capital cities in Eurocents per kWh, December 2019

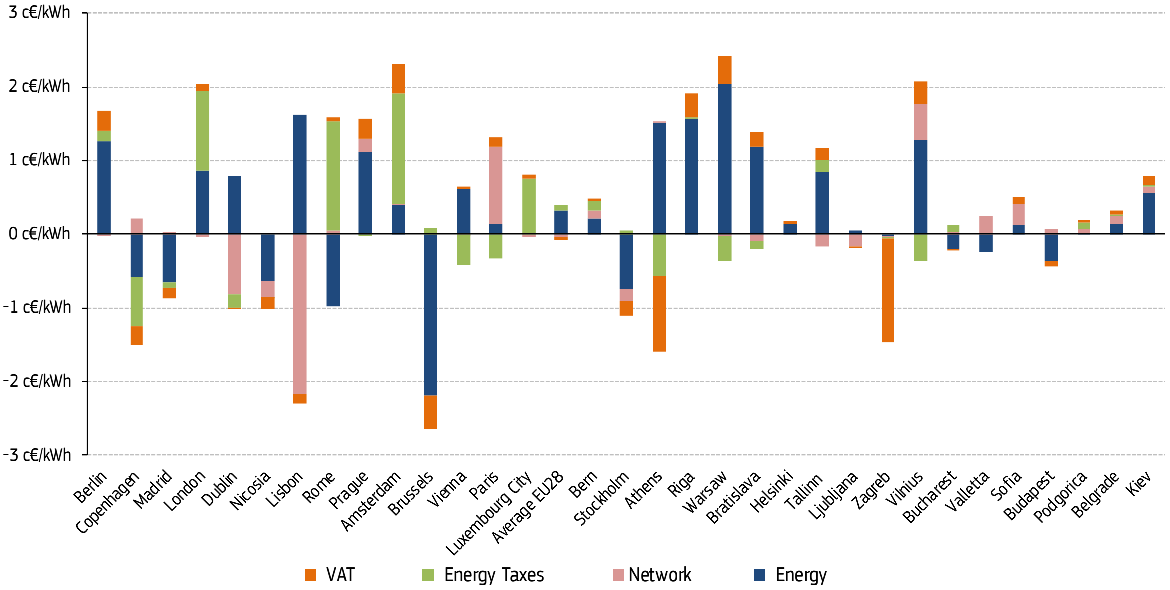


Source: Vaasaett

- Compared to the same month of the previous year, the largest price increases in relative terms in December 2019 were observed in Kiev (+22%), followed by Vilnius (+15%) and Warsaw (+14%). As shown in **Figure 59**, the energy component was the biggest contributor to rising prices in all three capitals. 13 of EU28 capitals reported prices lower or unchanged compared to the same month of the previous year, with Brussels (-11%), Zagreb (-10%) and Stockholm (-6%) posting the largest drops. The price fall in the Croatian capital was caused exclusively by a lowered VAT rate, whereas households in the Swedish and Belgian capital benefited mainly from lower prices of the energy component. Retail prices in Copenhagen were pushed down by a substantial cut in energy taxes, which was accompanied by lower energy costs.
- The energy component decreased in 10 EU28 capitals from December 2018 to December 2019, with the biggest drops in absolute terms registered in Brussels, Rome and Stockholm. 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 Sofia. Energy taxes decreased materially in Denmark, Greece and Austria, while going up in Italy, the Netherlands, the UK and Luxembourg.

Figure 59 – Year-to-year change in electricity prices by cost components in the European capital cities comparing December 2019 with December 2018

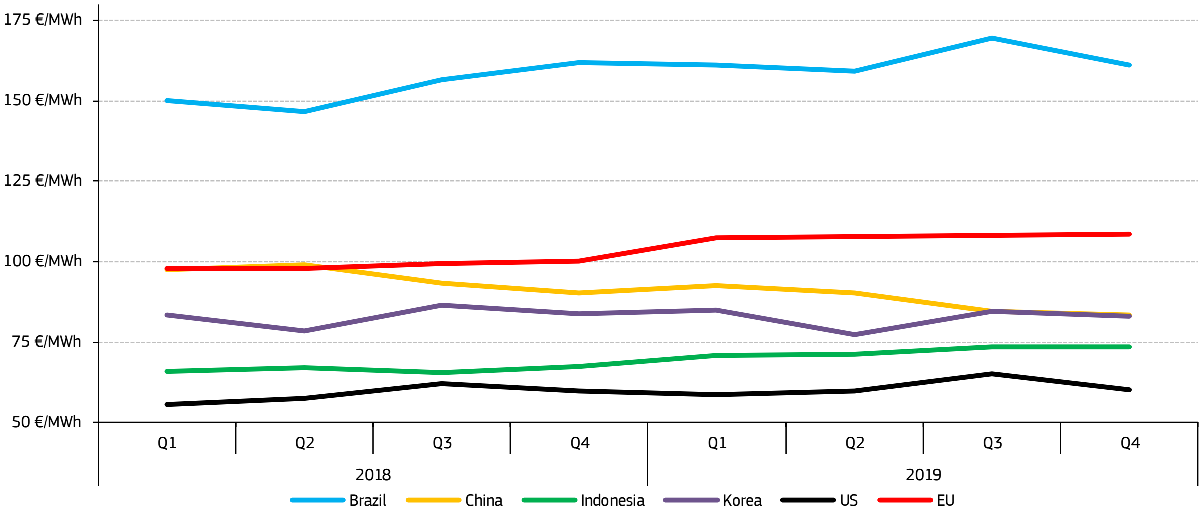


Source: Vaasaett

6.2 International comparison of retail electricity prices

- **Figure 60** displays industrial retail prices paid by consumers in the EU28 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 EU28 and Indonesia remained unchanged in Q4 2019 compared to the previous quarter. Other regions saw more dynamic developments, with the United States registering an 8% price drop quarter-to-quarter and the Brazilian industrial end-user prices falling by 5% quarter-to-quarter in euro terms. Industrial power prices continued to fall in China, levelling with their Korean peers.

Figure 60 – Retail electricity prices paid by industrial customers in the EU28 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 36% efficiency. Dark spreads are given in this publication, with the coal and power reference price as reported by *Bloomberg*.

Emission allowances' spot prices are defined as prices for an allowance traded on the secondary market and with a date of delivery in the nearest December.

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 49% efficiency. Spark spreads are given with the gas and power reference price as reported by *Bloomberg*.

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.