



Le réseau
de transport
d'électricité

2023 ELECTRICITY REVIEW

FULL REPORT

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KEY FINDINGS

2023: a new balance for the power system, departing from the trends of the last decade

Overview

The year 2022 was marked by three independent and simultaneous energy crises that, combined, placed the French power system under strain: threats to gas supply following Russia's invasion of Ukraine, leading to a surge in prices; a crisis in French nuclear power generation (at its lowest since 1988); and a hydropower generation crisis due to low rainfall (at its lowest since 1976). **Despite this very unfavourable context, the French power system showed resilience and managed to avert supply disruption.** This can be attributed to the decrease in electricity consumption within France and neighbouring countries, well-functioning exchanges with neighbouring countries in accordance with the rules of operation of the European common market, and the securement of gas supplies.

During 2023, the determinants of security of supply returned to a more favourable situation:

- **electricity generation from all low-carbon sources has increased significantly (nuclear power, hydropower, wind power, solar power);**

- **consumption decreased compared to the previous year**, facilitating the coverage of demand, in line with the trend observed in the autumn of 2022;
- **price levels decreased both on the spot market and the futures markets**, with a reduction of the risk premiums held by market players;
- **the electricity exchange balance once again became significantly export-oriented, reaching 50.1 TWh, and France reclaimed its traditional position as the leading electricity exporter in Europe (in volume);**
- **emissions related to electricity generation reached their lowest level since the early 1950s.**

Thus, the power system returned to a situation of equilibrium, in which concerns about security of supply have been largely mitigated. This “new balance” does not, however, constitute a return to the pre-crisis situation, given the substantial evolution in the production of various sources and the consumption structure since the late 2010s.

Detailed analysis

The clear downward trend of French consumption, which began in the autumn of 2022 amid the worsening energy crisis, continued throughout the year 2023. As a result, the volume of consumption (adjusted due to weather variations) for the year decreased by 3.2% compared to that of the previous year, reaching 445.7 TWh.

The total volume of electricity generation increased by 11% between 2022 and 2023 to 494.7 TWh, while remaining below pre-2020 levels.

- **The availability of the nuclear fleet recovered** during the year, compared to the historically low levels reached in 2022, but it remained significantly lower compared to that of the pre-crisis years. The volume of nuclear power generation rose to 320.4 TWh (compared to 279.0 TWh in 2022 and 394.7 TWh on average between 2014 and 2019);
- The year 2023 was characterised by **power generation records for both wind power (50.8 TWh) and solar power (21.6 TWh), which together accounted for nearly 15% of electricity generation**, thereby contributing to security of supply and the increase in the supply of low-carbon electricity in France and in neighbouring countries through exchanges. In 2023, France saw record new generation capacity additions for solar power and offshore wind;
- **Hydropower generation (58.8 TWh) maintained its position as the second-largest electricity source. Notably, there was a significant recovery compared to 2022**, primarily attributed to more abundant rainfall that enabled reservoir levels to remain high throughout the year;
- The simultaneous reduction in demand and the increase in low-carbon production collectively **diminished the reliance on fossil fuels, particularly gas** (with gas generation decreasing from 44.0 TWh in 2022 to 30.0 TWh in 2023);
- **The generation of electricity from coal has reached an unprecedented low and currently holds an insignificant position in the French energy mix** (0.17% of French electricity generation in 2023).

Overall, low-carbon sources continued to largely dominate the electricity mix: for nearly twenty years, French electricity generation has been among those with the lowest emissions in terms of greenhouse gases in Europe. **This was confirmed in 2023 with nearly 92% low-carbon production.** These factors have strengthened the national power system's role as a key contributor to the decarbonisation of Europe's electricity mix, through the export of a significant share of its low-carbon production.

The increase in electricity generation has led to reduced dependence on imports and increased export volumes: after an exceptional year in 2022, marked by a net import balance (16.5 TWh net yearly imports) for the first time since 1980, **France returned to its traditional role as a net electricity exporter in 2023, with a balance of 50.1 TWh.**

The easing of pressure on electricity supply had a positive impact on market prices, bringing them back to levels comparable to those seen in 2021.

The sharp mismatch between forward prices and market fundamentals observed in 2022, reflecting a risk premium specific to France due to market players' fears about the security of supply (which were disproportionate to reality), gradually diminished in 2023, leading to a convergence between France and neighbouring countries¹.

1. For forward prices for delivery in the 1st quarter of 2024.

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1. Consumption declined sharply, confirming the trend that began in 2022

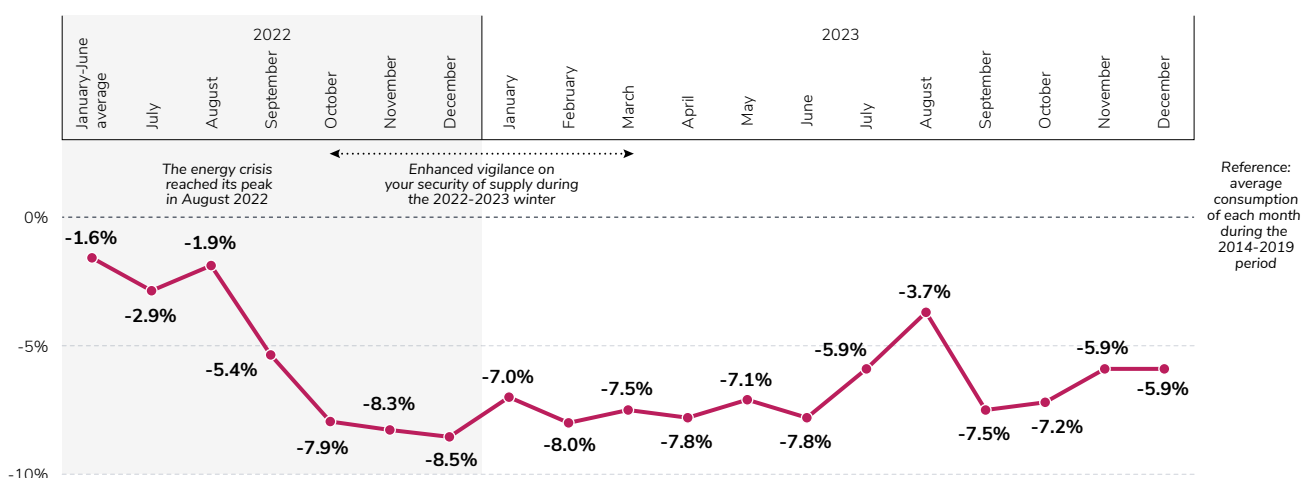
1.1 Consumption fell sharply throughout the year

Electricity consumption in metropolitan France, adjusted for the effect of weather hazards² and variations in the calendar, reached a level of 445.7 TWh in 2023, a decrease of 14.5 TWh (-3.2%) compared to the previous year and

32.4 TWh (-6.8%) compared to the period before the Covid pandemic (2014-2019).

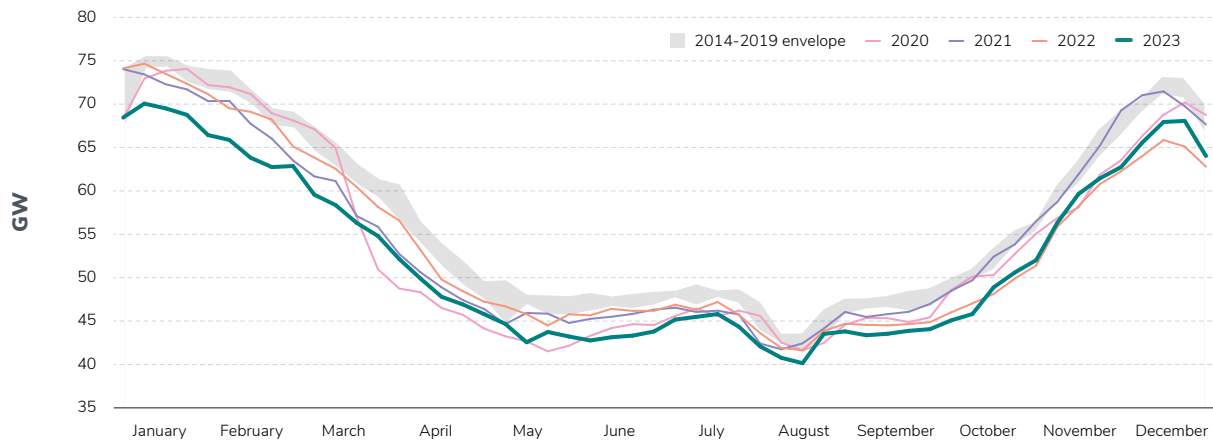
This reduction in consumption compared to the pre-crisis period reached 6 to 8% in most months of the year. This is a continuation of the last three months of 2022, which had shown a similar decline under the effects of the energy crisis.

Figure 1.1: Difference between the monthly consumption of 2022 and 2023, and the average consumption of the same months over the 2014-2019 period



2. An adjustment that allows a comparison from one year to the next, regardless of weather variability, and an identification of the structural effects that affect the level of consumption.

Figure 1.2: Average weekly consumption adjusted for weather variations (on working days only)



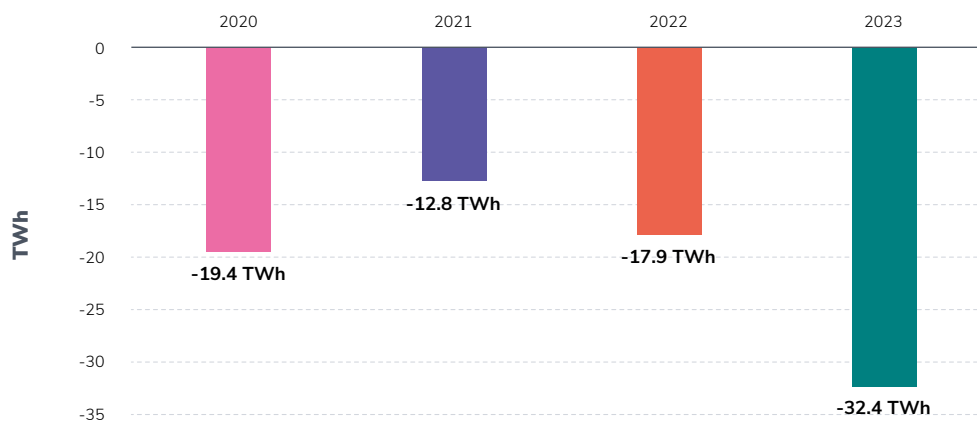
By way of comparison, the decrease in monthly consumption is, on average, of the same magnitude as that observed during the first national lockdown between March and May 2020, but it was of shorter duration at the time. This persistent reduction in consumption over the months in 2023 led to a gap between the level of consumption in 2023 and those of previous years, which increased throughout the year.

The decrease in consumption in 2023 is greater than the decreases observed in previous years, the

result of several economic, geopolitical and energy factors:

- **Incentives for energy efficiency and energy savings:** as early as the winter of 2022-2023, fears about the security of the gas and electricity supply led public authorities to encourage energy efficiency in administrations, businesses and the general public. At the same time, the ecoWatt scheme deployed by RTE has also helped to raise awareness among private individuals and economic players of the need to make energy savings.

Figure 1.3: Difference between the consumption of the years 2020 to 2023 and the average over the period 2014-2019



- **High energy prices:** Prices for energy and electricity traded on wholesale markets remained high in 2023 compared to their levels before the energy crisis,³ even though they were significantly lower than in 2022. The increases observed on these markets have been partially passed on to final consumers, who have been protected by several government schemes (price shield for private individuals, guaranteed electricity prices for small businesses, electricity buffers for certain companies⁴), which have limited the effects. However, the rise in electricity bills has remained substantial for consumers, against a backdrop of lasting misalignment between production costs and market prices, which has led to a rethinking of the way in which markets operate and the scope for public intervention (see the *Price* section).
- More generally, there has been **an increase in commodity prices and high inflation** since the end of 2022. All prices have risen sharply,

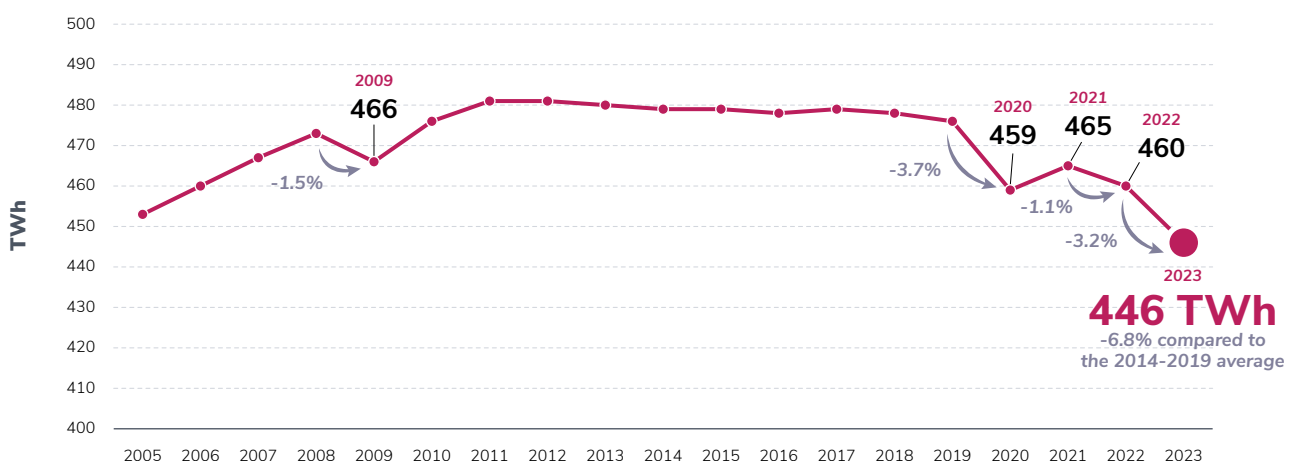
disrupting the supply and production processes of economic agents and household consumption.

- **The long-term effects of the COVID-19 pandemic:** since 2020, French consumption, and more particularly that of companies, has remained at levels below those observed before the Covid pandemic. This is evidenced by the manufacturing industry's production index⁵, which has never returned to the levels reached in the late 2010s.

1.2 After thirty years of slowing growth (1990-2019), consumption has been falling since 2020

The year 2023, like the three years preceding it, shows consumption levels lower than those of the period 2014-2019, which had already been characterised by an overall slowdown in the growth of electricity consumption.

Figure 1.4: Consumption adjusted for weather and calendar effects between 2005 and 2023



3. See the *Price* chapter.

4. Ministry of the Economy. *Rising energy prices: business support schemes, 2023*

5. Insee. *CVS-CJO Industrial Production Index (base 100 in 2015) – Manufacturing industry (NAF rev. 2, section level, item C), 2024*

This gradual slowdown, particularly marked over the decade 2010-2020, and observed both in France and in Europe, is mainly due to:

- a slowdown in economic growth following the 2008 financial crisis, as well as lower population growth;
- the continuing tertiarisation of economic activity and changes to France's industrial fabric;
- strengthening energy efficiency measures within buildings and equipment performance,

This phase of stability was followed in 2020 by a sharp decline due to the consequences of the Covid pandemic, when consumption reached its lowest level since 2005. French electricity consumption has never returned to the level of consumption observed in 2019. After a recovery in 2021, in 2022 it reached the same level as in 2020, due to energy saving efforts, and more broadly to the inflationary pressure linked to the triple European energy crisis. This downward trend continued throughout 2023, so much so

that it is necessary to go back to the early 2000s to find comparable levels of consumption. In addition, the decreases in consumption observed between 2019 and 2020 (-3.7%) and between 2022 and 2023 (-3.2%) are respectively the first and second largest since 1946.

While the slowdown observed in previous decades is the result of the structural factors mentioned above, the reduction in consumption observed since 2020 is the result of successive health and energy crises. It is likely that at least some of the effects of these crises will continue, due to changes in behaviour and changes or adaptation of equipment, both in individuals and within companies, as well as the cessation of certain economic activities. To achieve the climate goals set for the medium and long term, electricity consumption should however return to an upward trend linked to the transfer of uses from fossil fuels to electricity, although it is difficult to estimate precisely when this new trend will become visible.



FOCUS

Why adjust for climate consumption?

Climate-adjusted consumption is the electricity consumption that would have occurred if temperatures had been in line with the reference temperatures for the period. This calculation is carried out each year on the basis of consumption and temperature data. In this way, it is possible to identify variations in consumption due to structural trends (demographics, economic activity, changes in

behaviour) or to the economic climate (Covid pandemic, one-off efforts to reduce consumption, etc.) from what is solely due to the temperature sensitivity of the French power system. For example, if during a winter week temperatures are higher than normal for the season, gross consumption (i.e. unadjusted) will be lower than consumption based on normal temperatures.

1.3 Residential sector: the effects of the energy crisis on household consumption continued to be significant in 2023

As in other sectors, electricity consumption in the residential sector was lower than in previous years in 2023. While some of the reduction in household consumption is due to voluntary actions in favour of energy savings, surveys carried out since last year have shown that the effect of energy price levels and, more broadly, general inflation have been predominant.

The results of the survey⁶ carried out by RTE in partnership with the IPSOS institute on a large panel of French people (13,000 people) at the end of the winter of 2022-2023 suggest that financial arguments were the most important in the decision of households to take action to reduce electricity consumption in the winter of 2022-2023. Indeed, these arguments are mentioned by 79%⁷ of respondents to explain the implementation of eco-actions during the winter in question. More specifically, 59% of them said that their energy-saving actions were a response to rising electricity costs, and 46% said that they were an attempt to offset the rise in other expenses⁸.

In 2023, the economic context remained very restrictive for households, with inflation of 4.9%⁹ on average over the year. Regulated electricity tariffs increased for the first time on 1 February 2023,

by an average of 15%¹⁰, and a second time in August by an average of 10% when the regulated sales tariff was updated each year¹¹. As a reminder, inflation had been 5.2% throughout 2022, and the increase in the regulated sales price was limited to 4% on average for consumers benefiting from this price.

1.4 Industry: electricity consumption remained low in 2023 compared to pre-crisis levels

The unfavourable macroeconomic context of the years 2022 and 2023 weighed on industrial production in France, as evidenced by the observation of the production indices of several industrial sectors¹². In particular, the wood, paper and printing¹³, rubber, plastic and non-metallic minerals¹⁴ and metallurgy and metal product sectors¹⁵ have seen their production trends decline in volume since the beginning of 2022, a trend that continued in 2023.

The fall in the volume produced from the start of the 2022 year onwards, which continued into 2023, was more marked for certain branches whose production is energy-intensive, a sign that the strategies of economic players have been strongly conditioned by energy prices.

The decline in production in some industries has been reflected in the electricity consumption of the industrial sector. In particular, the electricity-intensive industries, connected to the electricity

6. RTE, *The willingness of the French to change their lifestyles in favour of the energetic transition*, 2023

7. Respondents could give up to two possible answers. 79% of them therefore gave at least one financial argument.

8. The survey questionnaire gave the possibility to choose several answers from the options listed, resulting in a total exceeding 100%. The other reasons put forward by respondents and cited by at least 20% of them were civic-mindedness (28% in 3rd position) and ecological sensitivity (20% in 4th position).

9. Insee, *In 2023, a slight slowdown in annual average consumer prices*, 2024

10. This increase, although significant, was limited by the price shield. Without it, energy bills would have increased by 120%. – Ministry of Ecological Transition, *Price shield for electricity*, 2023

11. An estimate made available by the French national energy ombudsman shows an increase of almost 26% over 2023 for an "average" consumer with a "basic" regulated tariff contract, and around 27% for a consumer with a contract distinguishing between peak and off-peak hours.

12. Divisions according to the French classification of activities level 2. Industrial production indices are indicators produced by INSEE and show changes in the value produced in constant euros, normalised in relation to a reference year.

13. Insee, *CVS-CJO Industrial Production Index (base 100 in 2015) – Woodworking, paper industries and printing (NAF rev. 2, level A38, item CC)*, 2024

14. Insee, *CVS-CJO Industrial Production Index (base 100 in 2015) – Manufacture of rubber and plastic products as well as other non-metallic mineral products (NAF rev. 2, level A38, item CG)*, 2024

15. Insee, *CVS-CJO Industrial Production Index (base 100 in 2015) – Metallurgy and manufacture of metal products with the exception of machinery and equipment (NAF rev. 2, level A38, item CH)*, 2024

transmission network, posted a consumption volume in 2023 of about 13.4% below that of the 2014-2019 period (a decrease of 8.9 TWh), and 4.3% (a decrease of 2.6 TWh) compared to the previous year. This represents around a quarter of the total fall in consumption over the period, while consumption by businesses supplied by the

transmission network accounts for around 13% of total electricity consumption. The reduction in consumption has in fact particularly affected the industrial sector¹⁶ and in particular the major electricity consumers. For example, the decrease in consumption was particularly strong for metallurgy (-20% compared to 2014-2019 and -8%

Figure 1.5: Sectoral distribution of consumption and consumption decline for the last four months of 2022 and the year 2023

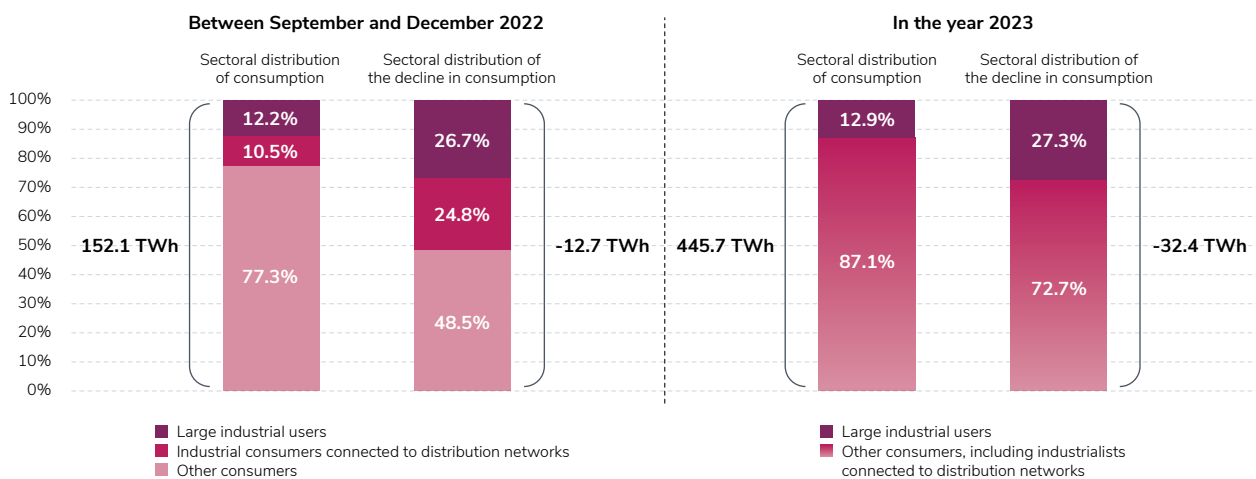
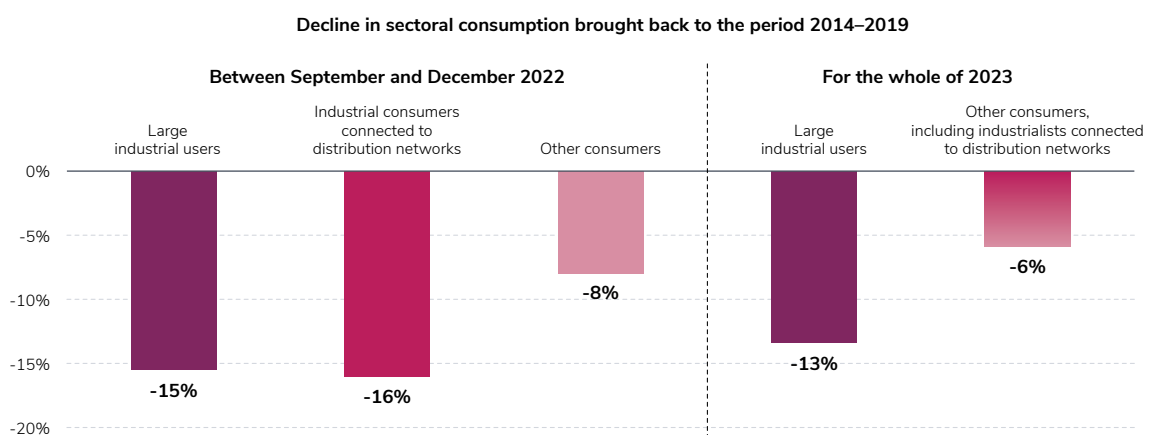
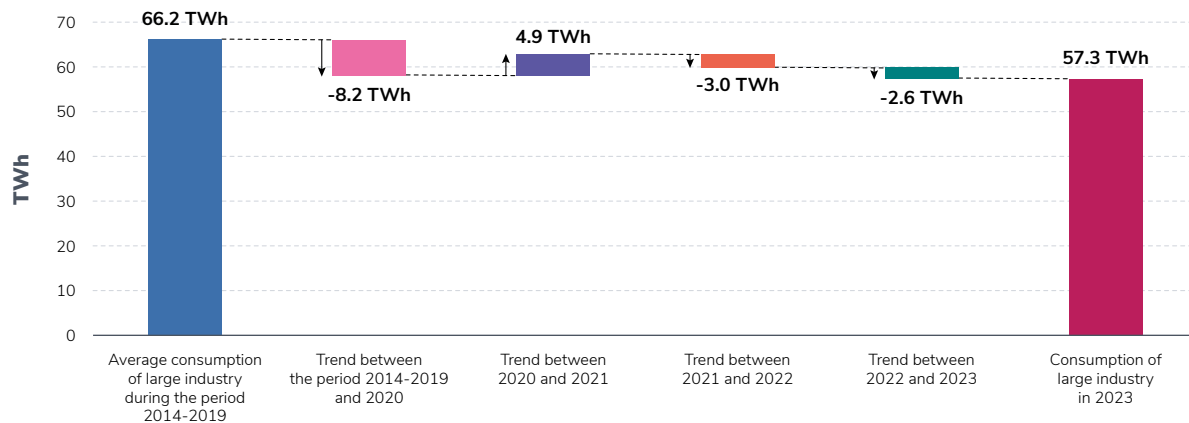


Figure 1.6: Sectoral decline in consumption in the last four months of 2022 and 2023 compared to the period 2014-2019



16. Data on the sectoral distribution of consumption for consumers supplied by distribution networks is not yet available, but the dynamic shows a trend similar to that for 2022 for industry supplied by these networks.

Figure 1.7: Breakdown of the trend of the consumption of the industry connected to the RTE network



compared to 2022) and paperboard (-26% compared to 2014-2019 and -14% compared to 2022), but also for the automotive sector¹⁷ (-24% compared to 2014-2019 but stable compared to 2022), although the latter is not one of the electro-intensive industries.

This marked development in 2023 is part of a more general trend which is that industry consumption is still very much affected by the

effects of the Covid pandemic. About a third of the decrease in consumption observed in 2023 compared to 2014-2019 was in fact during the latter. In addition, the decrease in consumption observed in 2022 and then in 2023 is greater than the increase in consumption observed in 2021, linked to the post-COVID economic recovery. At the end of 2023, the level of consumption of large industrial consumers therefore reached a level lower than that of 2020.

17. The variations shown relate to consumers supplied directly by the transmission network. A very large part of the electricity consumption of the metallurgy sector and the paper and board industries sectors is supplied directly by the transmission network. Electricity consumption in the automotive sector is more or less evenly split between the distribution networks and the transmission network.



FOCUS

Manufacturers and the rise in energy prices

Initial estimates of the electricity bill for industry point to a considerable increase in 2023: the DGE¹⁸ estimated in September 2023 that this bill would be around 29 billion euros in 2023, compared to 16 billion in 2022 and 10 billion in 2021. This increase has not been uniform across all industries, as some sectors are structurally more sensitive to energy commodity prices. Even within a sector, energy bills may have varied across companies, depending on the contracts negotiated with suppliers. INSEE showed in 2022 that increases in electricity bills depended on how

closely individual contracts were indexed to market prices, but also on when these contracts were renegotiated¹⁹.

Although this increase is significant, it has been contained by many government schemes aimed at businesses. This aid has mitigated the consequences of the increase in electricity prices on these consumers, either by directly reducing the bill of eligible industrial consumers, by facilitating the staggering of their payment to their suppliers, or by directly taking charge of part of it.

18. Ministry of the Economy, *What impact will the rise in energy prices have on industry?*, 2023

19. Insee, *In 2022, the average annual price of MWh of electricity increased by 45% and that of MWh of gas by 107%*, 2023

1.5 High temperatures over the year led to a fall in unadjusted consumption

According to Météo France²⁰, the year 2023 was the second hottest year on record in France, just behind 2022 (worldwide, it is the hottest year on record) with a temperature of 14.4°C or 1.4°C above the normals of 1991-2020.

Temperatures were higher than normal for the season throughout the year: monthly averages were almost always above normal for the season, and even more so in the second half of the year.

Summer 2023 ranks as the 4th warmest summer since 1900 behind the summers of 2003, 2020 and just behind 2018. Following on from the

Figure 1.8: Average monthly temperatures for 2022 and 2023, compared to the normal season

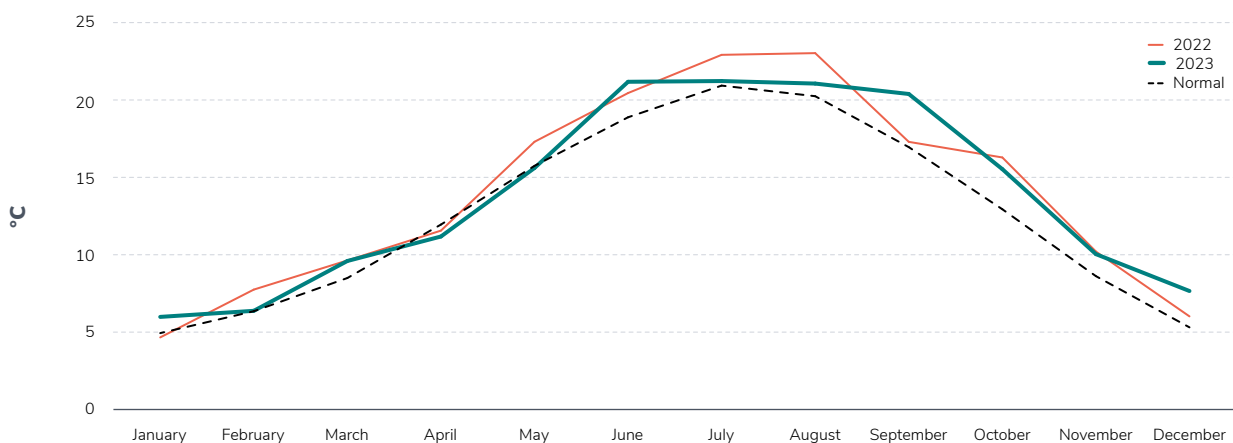
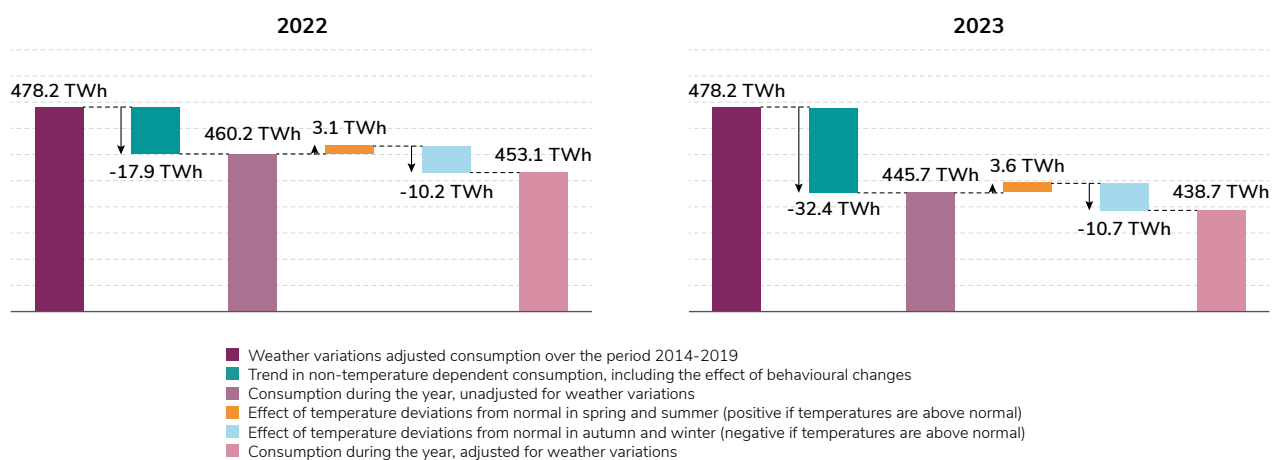


Figure 1.9: Comparison between average consumption over the period 2014-2019 (adjusted for weather-related variations), adjusted consumption in 2022 and 2023, and consumption not adjusted for weather-related variations in those years



20. Météo-France, *Climate report for the year 2023, one of the hottest years in France, 2024*

summer, autumn 2023 was the hottest autumn since measurements began, with September 2023 being the hottest month in France since 1900 and October 2023 the second hottest behind October 2022.

As a result, temperatures drove gross consumption down throughout the heating season, compared

with consumption at normal temperatures, and up in summer, albeit more moderately. Overall, as the rate of electric heating equipment is higher than the rate of air conditioning equipment, the effect of temperature on electricity consumption is predominant during the winter months, and as a result, gross consumption in 2023 is lower than adjusted consumption.

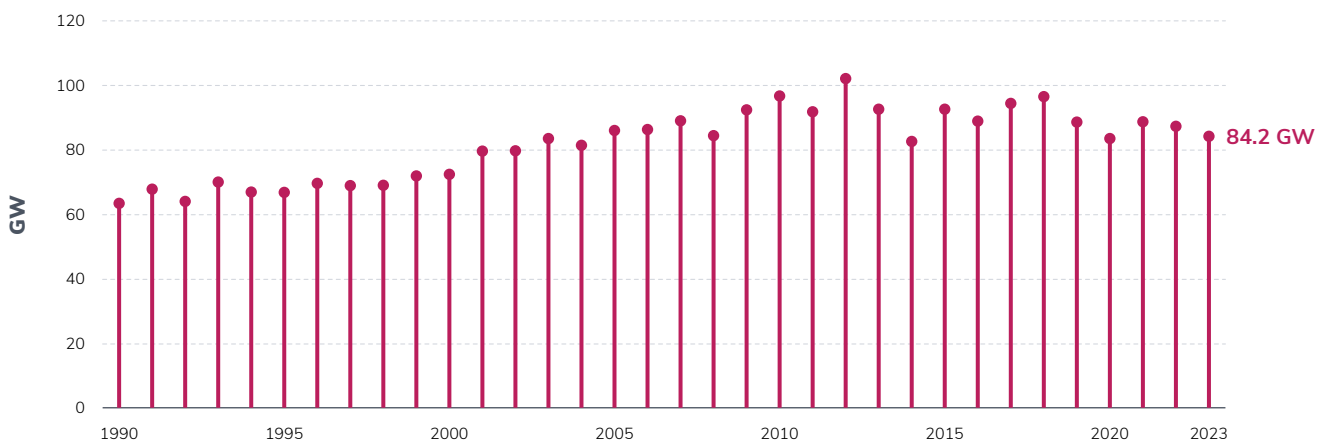
1.6 Peak consumption in 2023 remained similar to that of previous years

1.6.1 Consumption reached its maximum level of 84.2 GW on Monday, 23 January 2023, at 7 p.m.

Transient episodes of cold temperature, taking place mainly at the beginning of the year, occasionally pushed consumption up, so that the peak of consumption was reached on Monday, 23 January 2023, at 7 p.m. It reached 84.2 GW, about 7% less than the average annual consumption maximum over the period 2014-2019. This is due to the combined effects of energy savings and low temperatures (1.3°C on average during the day, i.e., more than 3.8°C below the normal season).

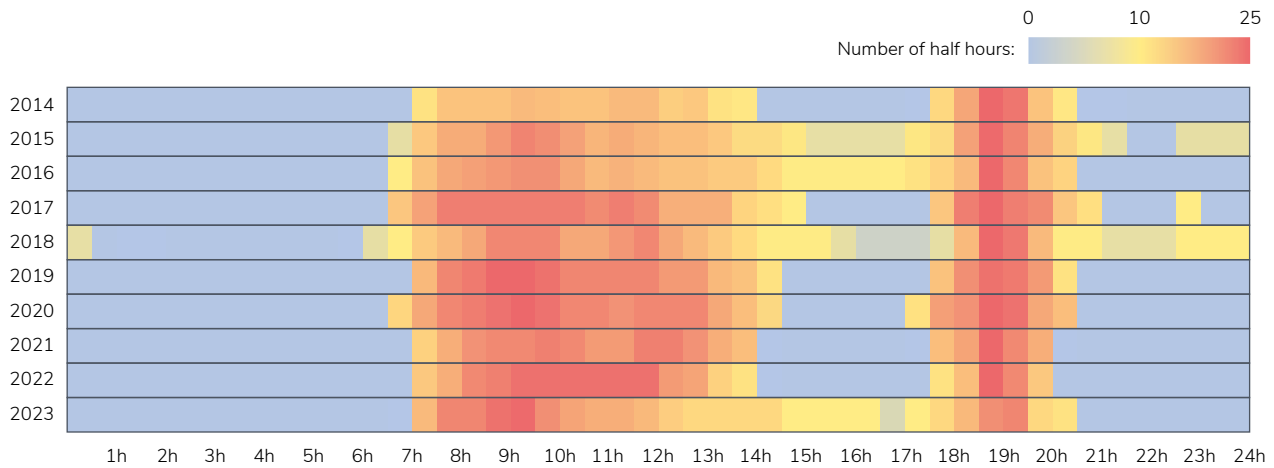
Peak consumption in 2023 was observed between 7 p.m. and 8 p.m., as in 31 of the last 34 years. This evening period corresponds to the time when a large proportion of the population switches on cooking, heating and lighting appliances. However, in 2017, 2020 and 2022, annual consumption peaks occurred during the morning plateau²¹, a period that coincides with the start of economic activity (production plants, heating in offices and shops, etc.). These two periods are the most heavily represented among those, with one of the highest levels of consumption in a year. By way of illustration, on Monday, 23 January 2023, the day on which the peak of annual consumption was reached in the evening, electricity consumption was also high during the morning plateau since it exceeded the threshold of 82 GW between 9 a.m. and 12 p.m., with a maximum of 82.7 GW during this period.

Figure 1.10: Peak electricity consumption in France between 1990 and 2023



21. On a cold day, electricity consumption levels can reach high levels for a longer period than during the evening peak, which is why this period is known as the "morning plateau".

Figure 1.11: Temporal distribution of half-hours of the year with consumption levels in the top 1% of the year



1.6.2 The highest levels of consumption were concentrated over seventeen days; mainly in late January

Even though it is more likely that the instantaneous maximum consumption over a year occurs in the evening, during a marked cold spell, the power calls recorded are significant on all the days concerned. This is because electric heating accounts for such a large proportion of electricity consumption in

buildings: it is used in almost 40% of residential homes and 30% of tertiary buildings. During the heating period, which traditionally extends from 15 October to 15 April, the use of electric heating leads to an increase in electricity consumption.

As a result, hourly consumption peaks over a year usually occur on a limited number of days, often consecutive, corresponding to the middle of cold spells.

Figure 1.12: Daily consumption according to average daily temperature (between 2014 and 2023)

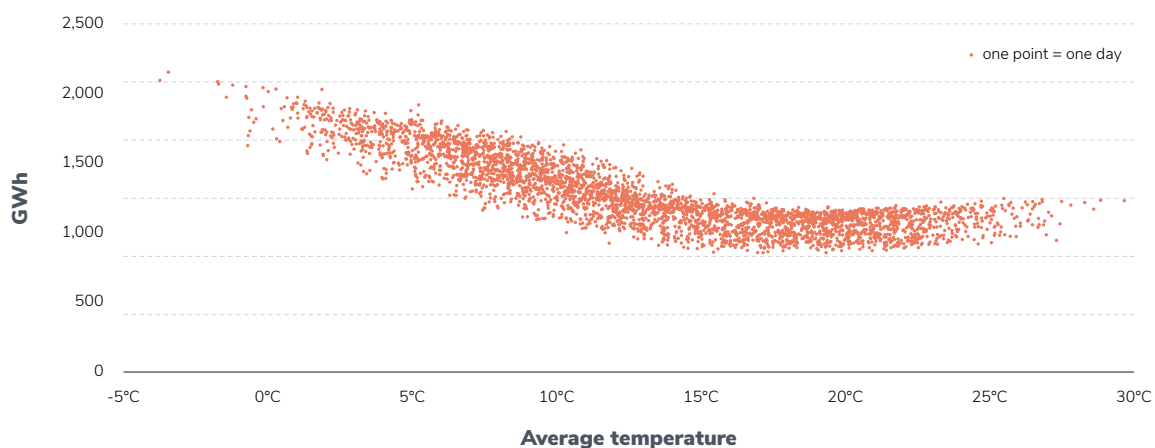
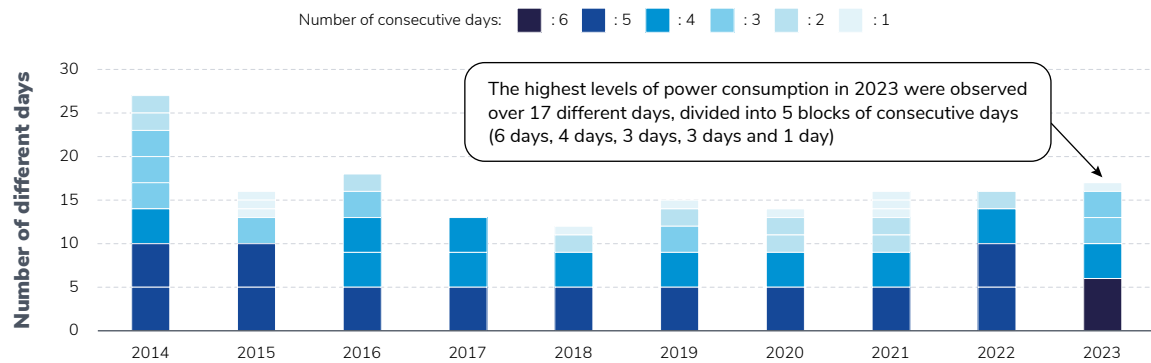


Figure 1.13: Number of different days on which half-hourly consumption levels are in the top 1% of the year



Reading: the graph represents the number of different days on which half-hours with a level of consumption of more than 99% of all half-hours are observed in each year. For example, the half-hours with the highest levels of power consumption in the year 2023 occurred on 17 different days. A second piece of information is provided by the colour of the histograms: a colour represents a number of consecutive days. For example, in 2023, the highest levels of power consumption were observed on 17 different days, including a block of six consecutive days, a block of four consecutive days, two blocks of three consecutive days, and one isolated day.

2. Overall electricity generation increased, thanks to renewables and the partial recovery of nuclear power generation

2.1 Overview

2.1.1 The production volume has risen sharply in 2023 compared with the historically low level of 2022

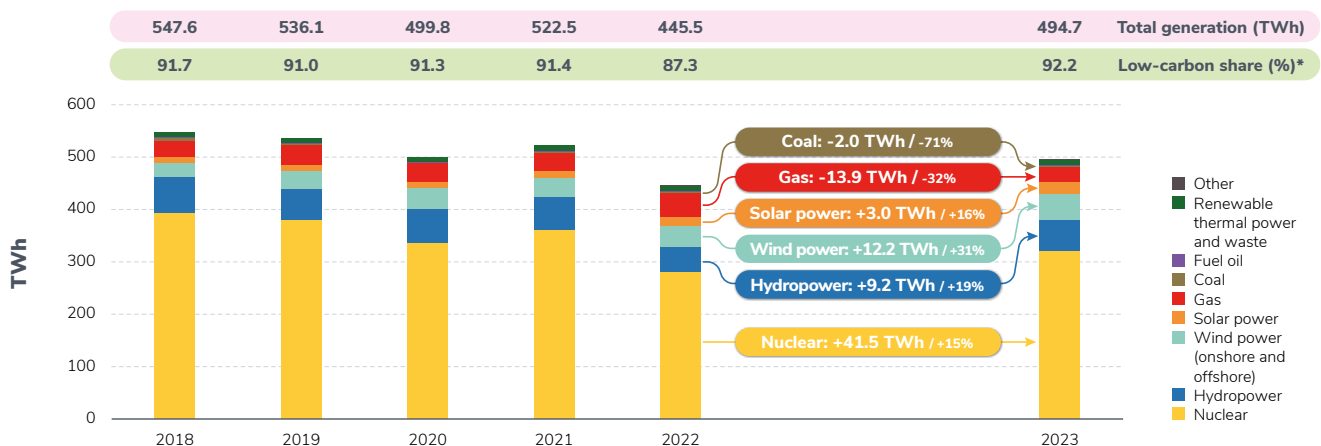
Mainly as a result of the crisis in nuclear power generation due to stress corrosion cracking, but also partly due to low rainfall, 2022 was an unusual year for electricity generation in France, both in terms of the total volume produced and the breakdown between the different generation mixes. In 2023, production returned to levels closer to historical norms, while still lagging behind pre-crisis levels.

Thus, the volume of production increased significantly in 2023 (+11%) compared to the historically low level of 2022, reaching 494.7 TWh (compared to 445.5 TWh in 2022). However, it is still lower than in the years preceding the health and energy crises (an average of 537.6 TWh over the period 2014-2019), and even

lower than in 2020 (499.8 TWh), which was nevertheless affected by lockdowns. Indeed, due to the structural decline in consumption and taking into account import and export levels, which have returned to a situation similar to that of **the pre-crisis period, the balance of the power system was reached in 2023 with lower generation and consumption than in 2020 or previous years.**

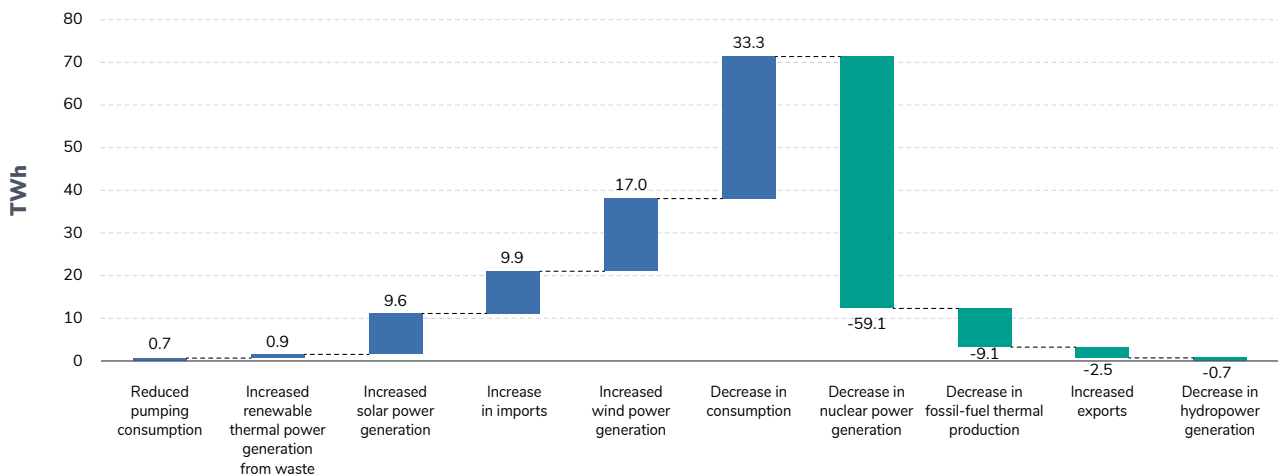
The increase in production in 2023 is the result, on the one hand, of the significant increase in the volume of nuclear power generation (+41.5 TWh) as well as, to a lesser extent, the volume of hydro (+9.2 TWh), wind and solar power generation (+15.2 TWh for these two generation mixes combined). On the other hand, the year 2023 saw a sharp decline in the production of fossil fuels (-16.5 TWh), which had been heavily used in 2022 to compensate for the lower availability of low-carbon generation mixes: the volume of fossil fuel production (32 TWh) even reached its lowest

Figure 2.1: Total electricity generation in France by type between 2018 and 2023, and share of low-carbon production



* Production from household waste is considered 50% renewable. Hydropower generation is subtracted from 70% of the pumping consumption of STEP, according to European Directive 2009/28/EC.

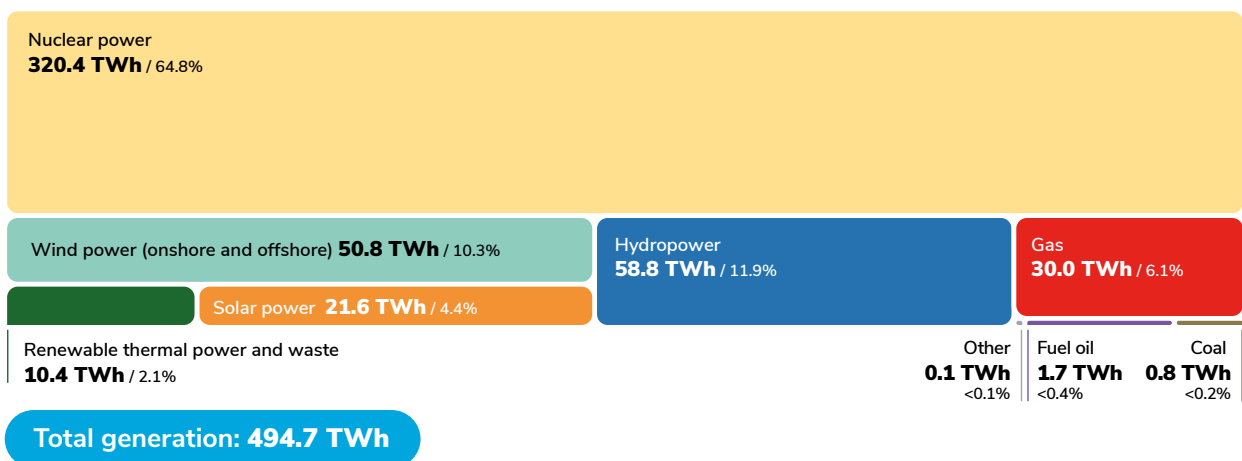
Figure 2.2: Gap in the determinants of electricity supply and demand in France, between 2019 and 2023



level since 2014. Although up sharply, nuclear power generation in 2023 continued to be affected by the repercussions of the stress corrosion cracking crisis. As a result, the source's production output (320.4 TWh) reached a low point close to

that of 1992, when there were several fewer reactors²². Similarly, despite its increase, hydropower generation in 2023 (58.8 TWh) remained slightly lower than the average volumes observed during the period 2014-2019 (61.7 TWh).

Figure 2.3: Total electricity generation in France in 2023 and breakdown by production source



22. In 1992, the current nuclear fleet was not yet fully in service, and several reactors were under construction. Six reactors have been commissioned since 1992 (Penly 2, Golfech 2, Chooz B 1, Chooz B 2, Civaux 1, Civaux 2) and two reactors have been shut down (Fessenheim 1 and Fessenheim 2).

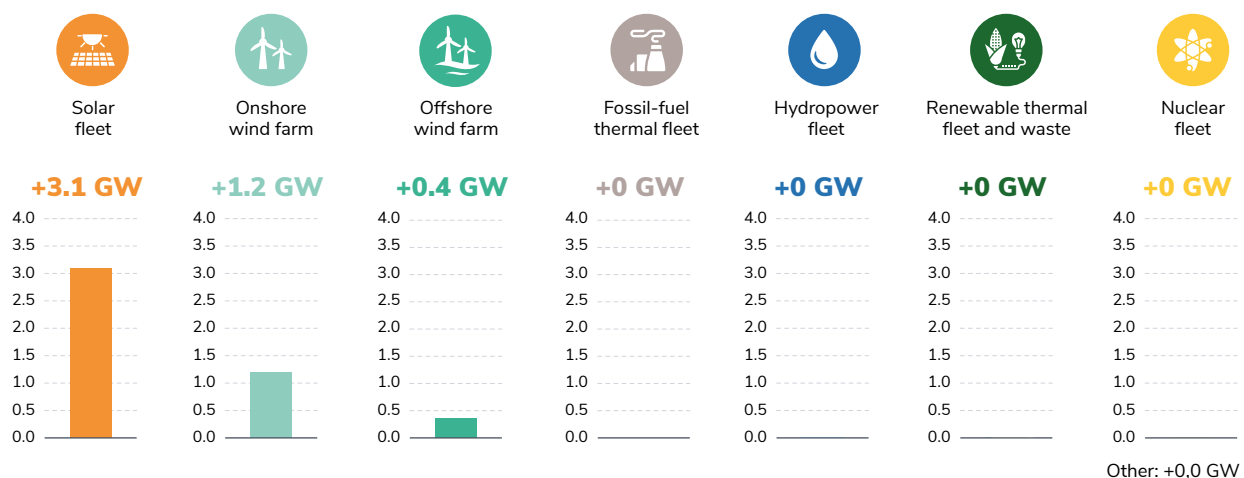
On the other hand, the year 2023 was characterised by production records for both wind power (50.8 TWh) and solar power (21.6 TWh). The trend is upwards, driven by the expansion of the fleet, and by 2023 this production will account for 14.6% of the French electricity mix. Wind power in particular has once again become the third-largest generation source ahead of gas, and its production volume is increasingly close to that of hydropower generation, with particularly abundant production during the autumn and winter months, when consumption is highest. Wind power (like solar power) thus contributes to the balance between electricity supply and demand, including during peaks in consumption (see the *Flexibility* section).

2.1.2 The installed fleet continued to grow thanks to solar and wind power

The increase in the capacity of French power generation in 2023 has been driven upwards by growth in wind power and photovoltaic solar power generation, which accounted for the vast majority of new capacity installed. At 31 December, installed capacity stood at 148.4 GW, an increase

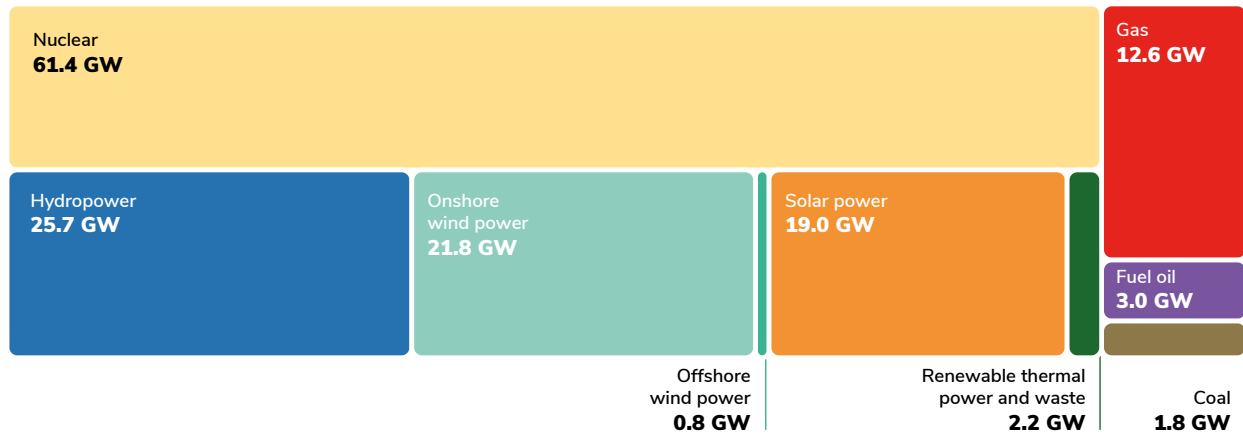
of 4.7 GW in one year. In particular, the photovoltaic solar power fleet reached 19.0 GW as of 31 December 2023 (+3.1 GW in one year), which is a record installation over one year, the previous record being 2.7 GW installed in 2021 and 2022. Onshore wind power farms reached approximately 21.8 GW, an increase of 1.2 GW in 2023. In addition, two offshore wind power farms are being installed in Fécamp and Saint-Brieuc: they should be completed in early 2024 to reach 0.5 GW each in the long term²³. If the capacity installed in 2023 (approximately 360 MW) is taken into account, this, combined with the capacity of the Saint-Nazaire wind farm commissioned in 2022, brings offshore wind power to 0.84 GW at the end of 2023. However, in the case of solar power and even more so in the case of wind power, the increase in renewable energy capacity has not been enough to achieve the targets set by the Programmation pluriannuelle de l'énergie (PPE) [Multiannual Energy Plan] by 2023, which were respectively 20.1 GW for solar power, 24.1 GW for onshore wind power and 2.4 GW for offshore wind power.

Figure 2.4: French electricity generation capacity by source in 2023



23. As of 31 December 2023, capacity connected to the network represented around 224 MW for the Fécamp wind farm and 136 MW for the Saint-Brieuc wind farm.

Figure 2.5: Electricity generation mix in France at the end of 2023 and breakdown by source



The nuclear fleet remained at its level of 61.4 GW, and is expected to grow in 2024 with the commissioning of the Flamanville 3 EPR. Hydropower and fossil-fuel thermal production plants remained stable compared with 2022.

Over the next few years, the generation mix will undergo major changes. In November 2023, the Government submitted for public consultation a document setting out the broad outlines of France's

energy policy: the French Strategy for Energy and Climate (SFEC). The programmatic component of the French legislation regarding energy production, which will be presented to the Council of Ministers in 2024, and the decree concerning the Multiannual Energy Plan (PPE 3) which will follow the promulgation of the law, will set out the objectives for the development of the energy mix in France for the period 2024-2033.

2.2 Nuclear: nuclear power generation has started to recover but is still far from its historic levels

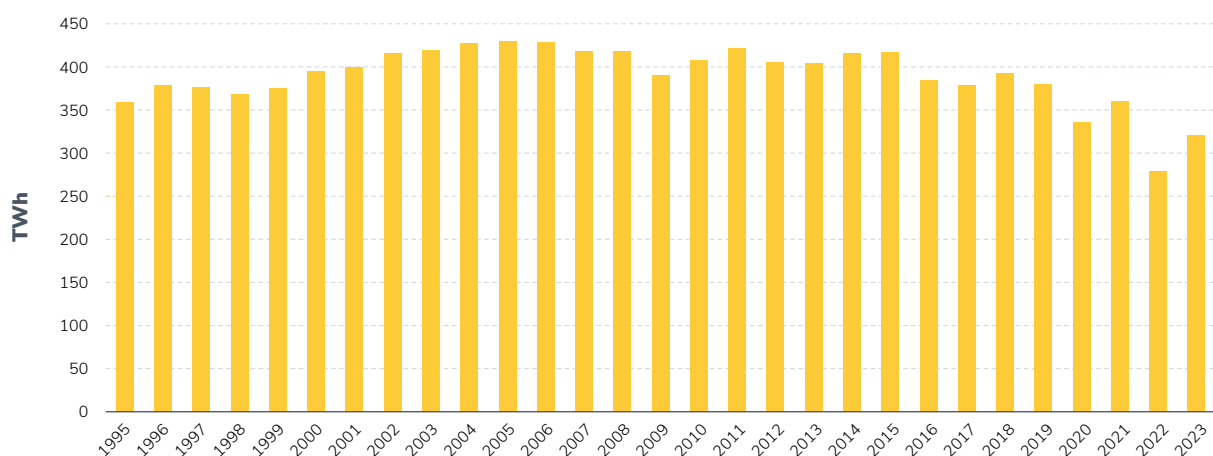
2.2.1 The production volume increased by 15% in 2023 compared to the previous year, but it remained lower than in 2021

Thanks to an improvement in the availability of power generation facilities, reflecting the progress of repairs linked to the phenomenon of stress corrosion cracking (SCC), the volume of nuclear power generation in 2023 has increased significantly (by 15%, or 41 TWh) compared with the previous year (279 TWh). Power generation reached 320 TWh, corresponding to 65% of the electricity generation mix in France. However, this level remains significantly lower (by about 40 TWh) than that of 2021, the first full year since the shutdown of the two reactors at the Fessenheim power plant²⁴ in June 2020. A fortiori, nuclear power generation in 2023 was lower than in 2019 (379 TWh) or even in 2020 (335 TWh), a year in which the Covid pandemic severely disrupted maintenance operations.

Looking in more detail at power generation for 2023, the level of production in the first three months of 2023 remained lower overall than in 2022, although the week of 6 to 12 February was characterised by the highest weekly production in 2023 (7.5 TWh). **From spring, production rose significantly above the level of 2022, and from autumn, it returned to levels close to the minimums observed during the period 2014-2019.**

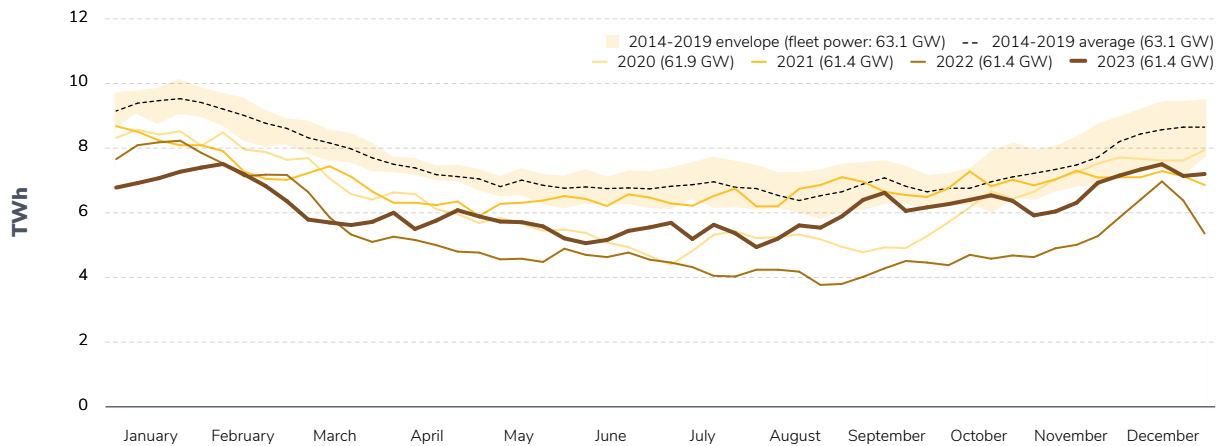
There were a few isolated drops in production between spring and autumn. In particular, at the end of May and the end of July, with the start of several scheduled shutdowns and the unplanned shutdown of a number of reactors in two low-consumption reactors. Power generation also showed a one-off drop in the first half of November, with the combined effect of slight delays to some planned shutdowns, shutdowns scheduled to save fuel in a favourable supply-demand balance, and also unplanned shutdowns (including 3.9 GW for three reactors disconnected due to network incidents caused by Storm Ciarán). The second half of December was also marked by unplanned shutdowns and short maintenance shutdowns,

Figure 2.6: Nuclear power generation in France between 1995 and 2023



24. Representing a total capacity of 1.8 GW.

Figure 2.7: Weekly production of nuclear power plants in 2023 and comparison with previous years



in addition to a downward modulation of nuclear power generation by the operator, against a back-drop of low consumption during the school holiday period combined with high wind power generation.

2.2.2 Unavailabilities related to the phenomenon of stress corrosion cracking have decreased in 2023

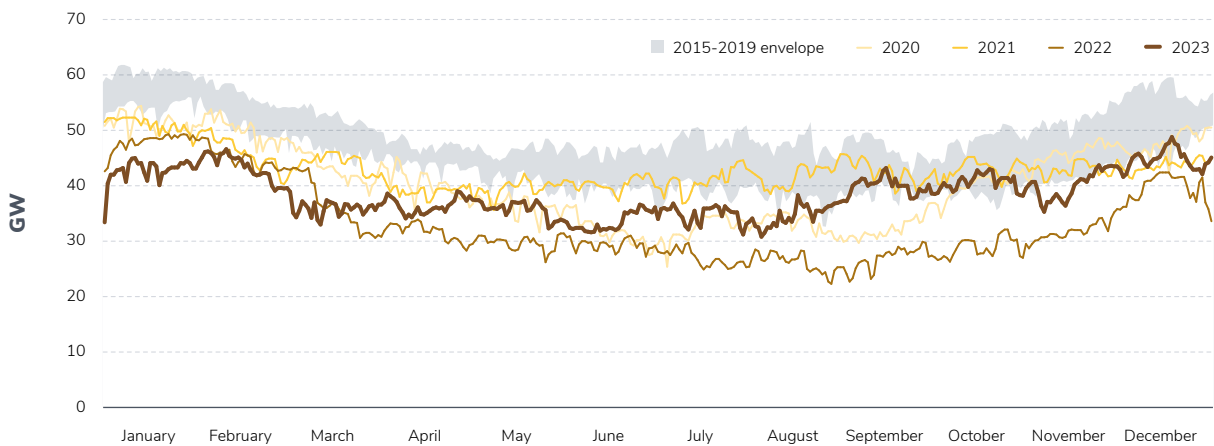
The increase in the power generation level in 2023 compared to 2022 is explained by the decrease in unavailability as a result of repair work related to the phenomenon of stress corrosion cracking. The availability of the fleet – assessed on the basis of the producer's declarations on the transparency platform²⁵ – thus amounted to an average of 38.6 GW in 2023, i.e., 5.4 GW more than in 2022 (33.2 GW) but 7.9 GW less than during the period 2015-2019 (46.5 GW). The availability rate of the nuclear fleet thus reached 63% in 2023 (compared to 54% in 2022 and 74% on average during the period 2015-2019). The level of availability therefore remained very low in 2023, despite a clear improvement compared to the minimum reached the previous year. The improvement in availability in 2023 compared to 2022 is explained by a decrease in unavailability

generated by shutdowns for routine maintenance (partial inspections, shutdowns for simple recharging, -3.9 GW), many of which had been affected by inspections and work related to stress corrosion cracking in 2022. Work related to stress corrosion cracking had also affected the duration of the ten-year inspections during the year 2022: thus, the decrease in unavailability generated by stress corrosion cracking was also reflected in the level of unavailability related to the ten-year inspections (-2.3 GW), while the unavailability caused by unplanned shutdowns increased slightly compared to the previous year (+0.9 GW).

During the first few months of 2023, the availability of the nuclear fleet remained very low by historical standards, remaining at a level close to that at the end of 2022 but lower than that observed during the same period in 2022. From March, the availability of the fleet exceeded that of the previous year, amounting to 35 GW on average. From September onwards, the consecutive restarts of a large number of reactors enabled a return to levels of availability close to those of 2021, and to historic minimum availability levels. There were occasional drops in availability in May,

25. The availability returned here is assessed by RTE on the basis of the declarations of unavailability published by the producer on the transparency platform. These include all types of shutdowns as well as partial unavailability and load increases. These availability factors are a little lower than the "K_s" availability factors published by EDF, which reprocesses certain shutdowns (for fuel saving or power reduction, for example), to account for them in the "K_s" utilisation coefficient. The K_s of the year 2023 will be published in 2024 by EDF on the site explore.data.gouv.fr.

Figure 2.8: Changes in average daily nuclear power availability in 2023 and comparison with previous years



July and November (see previous section on production trends). Peak availability, at 49 GW, was reached on Monday, 18 December, before falling over the last fortnight of December due to the shutdown of three reactors to save fuel in a context of low consumption and high wind power generation.

Although the risk to security of supply was lower in 2023 than in 2022, the nuclear fleet has not returned to nominal operation.

The nuclear fleet's production has indeed recorded a structural decline compared to the maximums reached in the early 2000s. The closure of the two Fessenheim reactors accounts for part of this reduction, but it is far from the majority of it: the drop in availability between 2000 and 2023 represents the equivalent of the closure of 14 reactors of 900 MW.

The reduction in nuclear power generation is not due to the development of renewable energies: modulating the output of reactors is a technical skill for their operators, enabling them to optimise production according to market prices (i.e., producing less during periods of low prices to save fuel and maximising output during periods of higher prices). In reality, there are very few situations in which

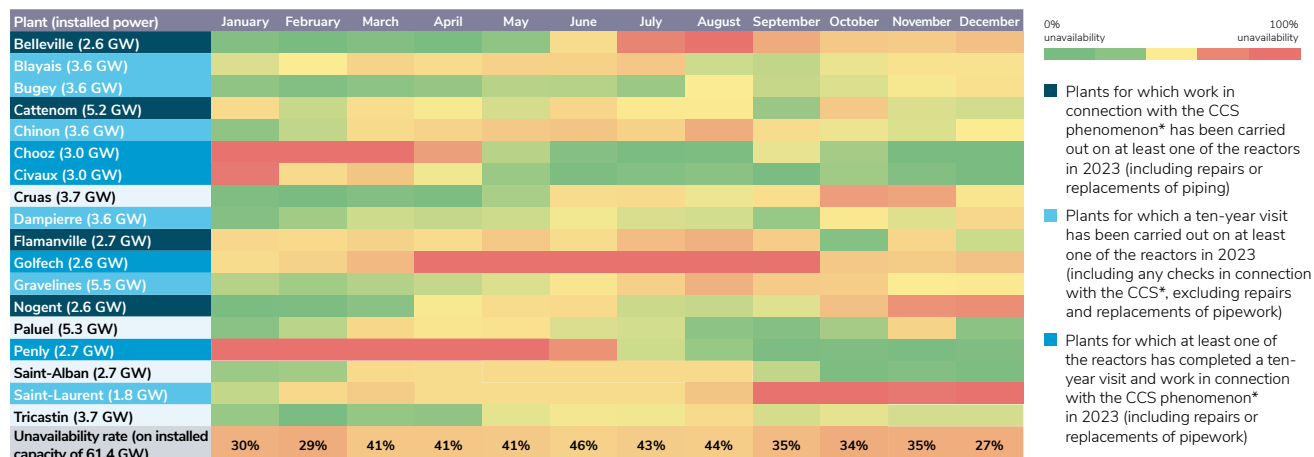
modulation would be “forced” due to a lack of outlets (in such cases, nuclear power is often not the only one to modulate, as the most recent renewable fleets are also shut down).

This downward trend in nuclear power generation is due to the scale of the industrial programme required to extend the operating life of the reactors and to take account of feedback from Fukushima. The Covid pandemic, which disrupted maintenance schedules at a critical time in the ramp-up of the biggest projects, and then the identification at the end of 2021 of a generic stress corrosion cracking defect, have ended up constraining an already highly optimised schedule.

Over the next decade, the challenge is to return to higher levels of availability and production than in recent years, which is one of the essential levers for achieving industrial objectives and initiating the transition to a low-carbon economy. In drawing up the ten-year projections in the latest “*Bilan prévisionnel*” (Generation Adequacy Report), RTE assumed a rapid return to an average annual production volume of around 360 TWh, including the Flamanville EPR, and considered a level of around 400 TWh, as in the 2010 decade, as the top scenario²⁶.

26. RTE, 2023-2025 Generation Adequacy Report, Electricity generation and storage, 2023

Figure 2.9: Breakdown of total unavailability by nuclear power plant and by month in 2023



* CCS: Stress corrosion



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The various causes of reactor unavailability

Nuclear reactors are regularly shut down for different reasons (maintenance, refuelling, etc.), with frequencies and durations that vary according to the objective. The reactors are generally shut down every 12 to 18 months for refuelling, for a period of about 40 days²⁷, every three to four years for partial safety inspections to the reactor (lasting about 3 months) and every ten years for ten-year safety inspections (for a period of at least 6 months). Safety inspections are then combined with refuelling. In addition to these scheduled shutdowns, unplanned shutdowns also impact the availability of the reactors.

However, since 2014, as part of the “Grand Carénage” [Great Refit] programme²⁸, shutdowns for maintenance and improvement to

extend the life of the plants have increased. In this context, and taking into account the schedule of ten-year inspections, the winters between 2021-2022 and 2022-2023 had already been identified by RTE for several years²⁹ as being constrained from the point of view of security of supply. For 2023, this resulted in particular from the positioning of three ten-yearly inspections during the month of January.

In addition to these standard shutdowns, in 2022 and 2023, there was the significant effect of checks and repairs related to the phenomenon of stress corrosion cracking identified by EDF at the end of 2021. Checks and repairs were carried out either during

27. Provisional period usually declared by EDF in previous years as part of the Transparency regulation. Actual durations may vary.

28. Investment programme for the renovation of the existing nuclear fleet approved by the EDF Board of Directors on 22 January 2015. As well as renovating and extending the lifespan of the reactors, the aim is to increase their level of safety and incorporate the improvements designed in the wake of the Fukushima accident in 2011.

29. RTE, *Generation Adequacy Report of the electricity supply-demand balance in France – 2019 edition, 2019*



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specific shutdowns, in particular in 2022, or during scheduled shutdowns, as was the case in 2023. In addition, the effects of the delays in maintenance schedules linked to the Covid pandemic, which had continued to affect the availability rate of the fleet in 2022, were not felt in 2023.

According to the operator's estimates, made public in December 2023, nuclear power generation could return to a level within the range of 335-365 TWh of annual production as early as 2025³⁰. By way of comparison, the production level for the year 2021, for an equivalent fleet, was 361 TWh.

2.2.3 Changes in unavailability linked to the phenomenon of stress corrosion cracking

EDF's strategy for managing stress corrosion cracking (SCC) has been under development since the end of 2021, in line with the consolidation of knowledge as inspections are carried out. From 2023, EDF systematically carried out the preventive replacement of pipework considered as sensitive in P'4 reactors³¹. In 2023, 14 reactors were unavailable for at least one day as part of a shutdown, including work for SCC, the same number as in 2022. However, the shutdowns that started in 2023 were significantly shorter than the previous shutdowns: the average shutdown duration was 5 months compared to 12 months on average for the shutdowns initiated in 2021 and 2022.

After the Nogent 1 and Belleville 1 reactors were reconnected to the network on 29 and 30 December 2023, only one reactor (Cattenom 4³²) remained for which work in connection with the phenomenon is still scheduled for 2024, as part of its 3rd ten-year inspection. However, actions are still planned until 2025, including the inspection of welds repaired at the time of the construction of the reactors, which have been identified as components sensitive to this phenomenon. A defect of this type³³ was discovered at Penly 1 in March 2023, with an impact on forward prices in France for the year 2024 (see *Price* section). The investigations on this reactor have made it possible to determine that it was a defect specific to this installation and not a generic defect³⁴. EDF has nevertheless updated its strategy by accelerating the planned pace of inspections of the 320 repaired welds identified as sensitive on several reactors³⁵.

30. Estimates excluding EPR of Flamanville. – EDF, *Nuclear power generation in France in 2026*, 2023

31. EDF, CSC: *update of the information note (16/12/2022)*, 2022

32. EDF, *Condensed consolidated financial statements for the six months ended 30 June 2023*, 2023

33. Very atypical in its depth (155 mm long and 23 mm deep for a thickness of 27 mm).

34. Senate – Committee on Economic Affairs, *Hearing of Messrs Bernard Doroszczuk, Chairman, and Olivier Gupta, Director General of the Nuclear Safety Authority (ASN)*, 2023

35. EDF, CSC – *Update of the information note – "Update of the control strategy"*, 2023



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Assessment of the impacts of global warming on nuclear power generation

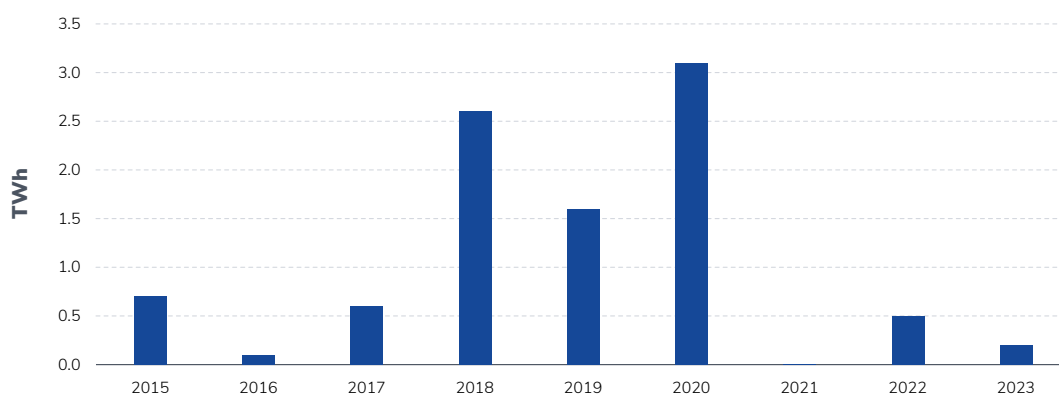
The nuclear fleet is subject to regulatory standards on waste heat and the sharing of water resources during heatwaves and droughts. These episodes are all the more restrictive on nuclear power generation and the balancing of the power system since they generally take place in summer and over short periods. According to RTE's estimates, the risk of unavailability linked to global warming could increase by a factor of two to three by 2050³⁶. ASN reminded EDF in particular of the need to anticipate this risk in the coming summers³⁷.

In May 2023, EDF presented an intervention programme dedicated to these issues. The operator also shared its estimate that production losses due to these phenomena had represented 0.3% of annual production on average since 2000 but could represent 1.5%

by 2050, which confirms the orders of magnitude anticipated by RTE. According to EDF, the main power plants at risk are Saint-Alban, Tricastin, Bugey, Blayais, Golfech and Chooz.

In 2023, these constraints forced EDF to reduce its production on several sites: Bugey (July and August), Golfech (August), Saint-Alban (October) and Blayais (October), totalling 0.2 TWh of production losses, which represents less than 0.1% of production in 2023. This is a relatively low level compared with previous years, as was the case in 2022, when many reactors were already shut down in the summer, in connection with work on stress corrosion cracking. In 2021, production losses were very low thanks to favourable summer temperatures and rainfall conditions³⁸.

Figure 2.10: Annual nuclear power generation losses due to environmental constraints between 2015 and 2023



³⁶. RTE, *Energy futures for 2050 – Full report*, 2022

³⁷. ASN, *Adaptation of EDF nuclear power plants to climate change*, 2023

³⁸. EDF, *Universal Registration Document 2021, 2022*

2.3 Hydropower: Hydropower generation returned to levels in line with historical averages thanks to good stock replenishment

2.3.1 Hydropower generation increased compared to that of 2022, while remaining below the average level of the reference period

The level of production from hydropower plants reached 58.8 TWh in 2023, an increase of 18.6% compared to 49.6 TWh produced in 2022, which had represented the lowest level since 1976. Production in 2023, however, remained 5.1% lower than that of 2021 (62.0 TWh produced that year) and is 4.7% below the average of the period 2014-2019 (61.7 TWh). In 2023, the hydropower source remained the second-largest source of electricity generation after nuclear power, and the largest source of renewable production, slightly ahead of onshore wind power. Thus, the contribution of hydropower to electricity generation in France in 2023 represented 11.9% of total production.

Across all generation mixes, hydropower generation was very low from January to March (except for two weeks in January), months that usually account for a significant share of the

annual total. The very low production volume during the first three months of the year is linked to responsible management of the hydropower stock by players in a context of low rainfall. The particularly low level of production during the month of February is explained by a sharp decline in run-of-river production from power plants due to their high dependence on rainfall. The availability of hydropower resources, and consequently their production volume, then returned to levels close to the bottom of the range for the 2014-2019 period, due to more favourable rainfall. From October onwards, thanks in particular to the very high level of available stocks, production levels even reached some of the highest levels seen in previous years.

All types of power plants (excluding PSPs) saw their electricity generation levels increase in 2023. For power plants with water reservoirs, the very high stocks from mid-April allowed a clear improvement in production during this period compared to 2022, in contrast to the low levels achieved during the winter of 2022-2023 due to low rainfall. In detail, the output of lake-type power plants, generally located in high mountain areas, has increased by 41.7% compared with 2022, and lock-type power plants (often in mid-mountain areas) are up

Figure 2.11: Weekly production of hydropower plants in 2023 and comparison with previous years

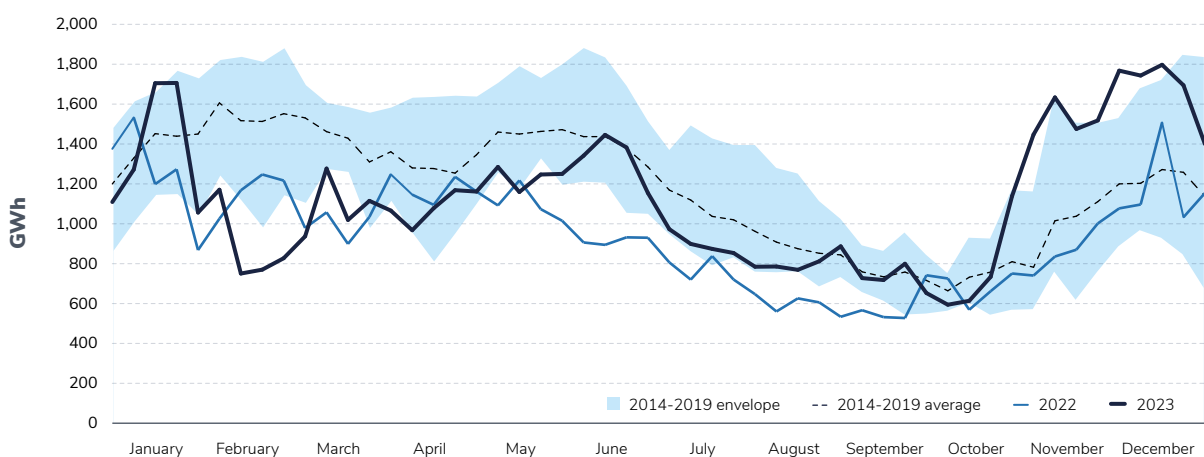
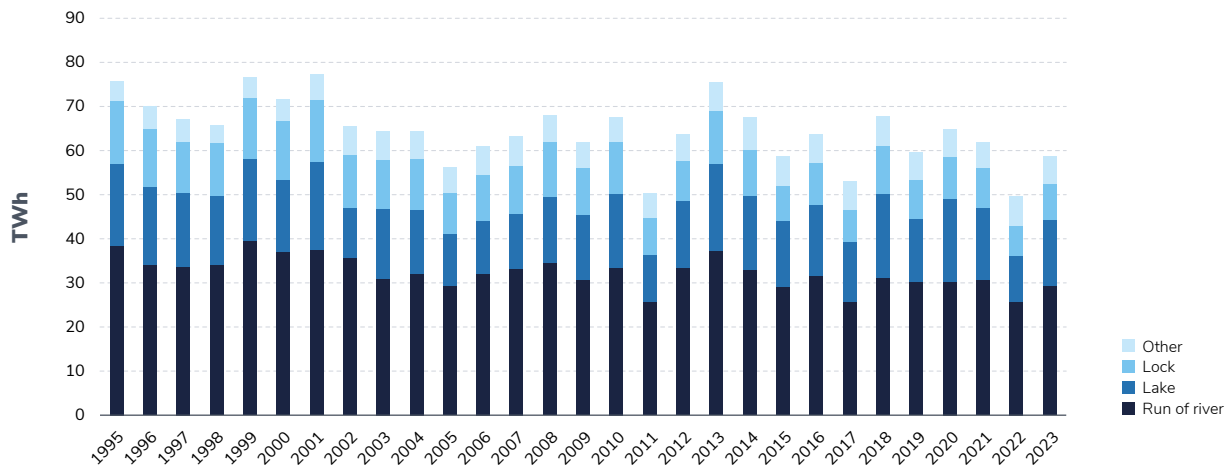


Figure 2.12: Hydropower generation in France between 1995 and 2023



by 24.5%. Finally, the level of run-of-river production from power plants increased by 14.2% over the year. Due to very limited rainfall in February, run-of-river power plants produced a very low volume of electricity before returning to production levels close to those of the period 2015-2019 over the rest of the year thanks to abundant rainfall volumes.

2.3.2 A year of contrasts, alternating very severe drought and abundant rainfall

From a meteorological point of view, 2023 was the second hottest year in France, since the beginning of the 20th century, behind 2022. The year was very mixed, depending on the period. On the one hand, rainfall volumes were very limited throughout the winter, with a particularly large deficit during the month of February (-75% compared to the average for the period 1991-2020³⁹), then also remained in deficit during the summer and until mid-October. Summer 2023 was also the 4th-warmest summer since 1900, only surpassed by 2003 and 2022 and at the same level as 2018⁴⁰. The month of September 2023 was the hottest in France since 1900, as

was the autumn of 2023, according to Météo France. On the other hand, heavy rainfall was recorded at several points during the year: heavy snowfalls in the second half of January, numerous and frequent rainy spells in March and then alternately in April and May, and very intense rain from the second half of October.

2.3.3 Hydropower stock above historical averages from May

At the beginning of the year, the level of hydropower stocks in France was close to the average level of 2015-2021, but the use of lake or lock-type power plants to generate electricity was relatively limited over the first three months of the year, and in particular in February and March. This is due to responsible management of the hydropower stock following the low rainfall during this period, in a context of relatively low consumption compared to levels in previous years (see the Consumption section) and high wind power generation in March.

From spring onwards, stock levels rose thanks to abundant rainfall, reaching one of the highest

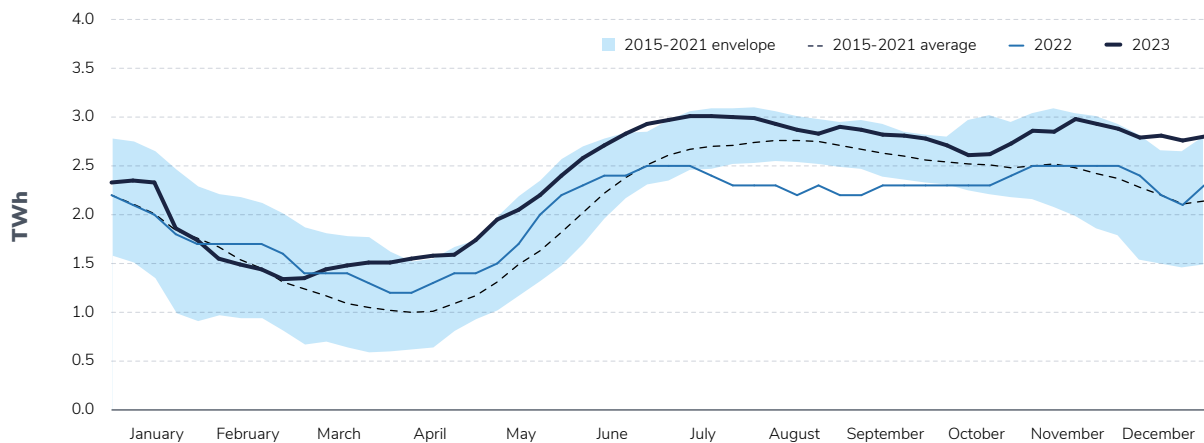
39. Météo France, *Climate report February 2023, 2023*

40. Météo France, *Climate report for the year 2023, 2024*

levels since 2015 over the rest of the year. This development is the result of four factors in particular: the level of consumption remained well below the 2014-2019 levels (see the Consumption section); operators kept their responsible management of the stock with a view to the winter of 2023-2024; rainfall was much more favourable to the replenishment of the

stock over this period, in particular in November and December, while the level of electricity generation from lake-type installations reached its highest level in 2023 over these two months, and finally, wind power generation reached two new peaks in November and December, thus limiting the use of lake stock for electricity generation during these periods.

Figure 2.13: Weekly changes in hydropower stocks in 2023 and comparison with previous years



2.4 Record levels of onshore wind power generation thanks to the development of wind farms and favourable conditions

2.4.1 A higher load factor, thanks to a particularly windy year

In 2023, weather conditions were favourable to wind power generation: the load factor for onshore

wind power was 26.2%⁴¹, compared to 21.6% in 2022. This is higher than in the previous two years but lower than in 2020, which was characterised by a record level of 26.6%.

The increased load factor, combined with a growing installed base (+1.2 GW for onshore wind compared with 2022), has resulted in a record production volume for 2023 (48.9 TWh).

Figure 2.14: Change in annual load factor for onshore wind power between 2014 and 2023

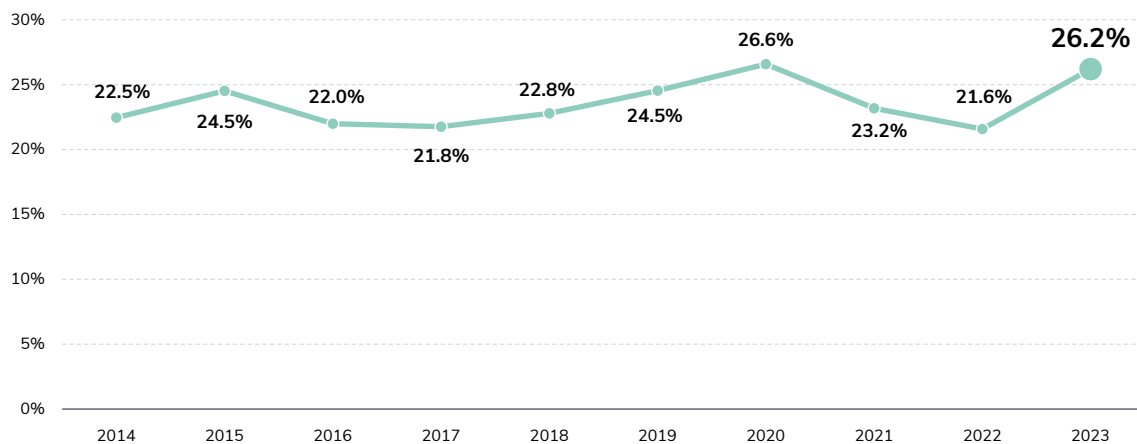
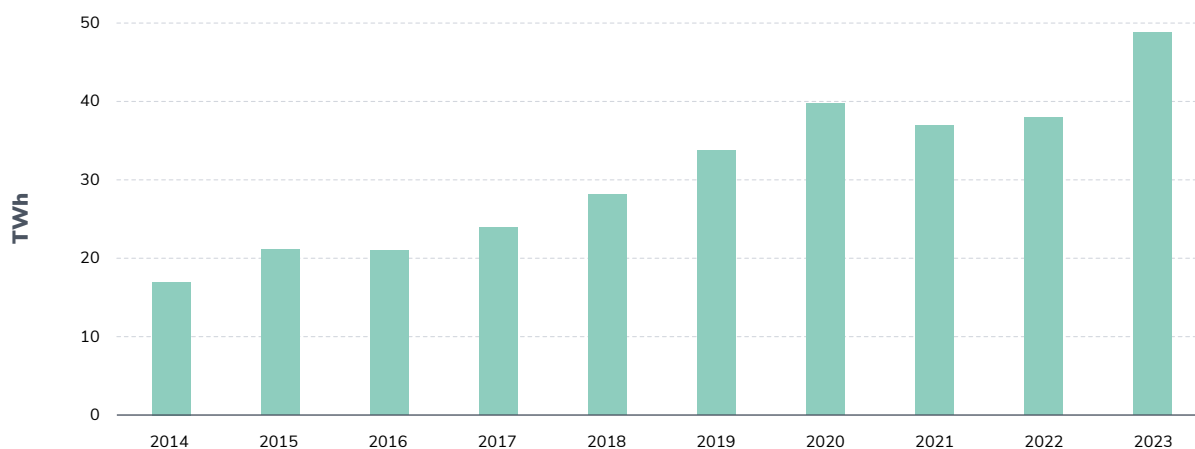


Figure 2.15: Change in annual production volume for onshore wind power between 2014 and 2023



⁴¹. Average annual rate calculated as the average of load factors at 30-minute time intervals. The value for the whole of 2023 is an initial estimate, which will be updated at the end of February with consolidated data.

The previous maximum of 39.6 TWh, dating from 2020, was exceeded thanks to the development of the fleet (4.3 GW between 2020 and 2023) and despite a slightly lower load factor. This “fleet effect” was not sufficient in 2021 and 2022 to exceed the production level of 2020 due to less windy years, characterised by lower load factors⁴².

The rate of coverage of consumption by onshore wind power generation amounted to 11.3% on average in 2023, a clear increase compared to 2022 (8.4%)⁴³ and for the first time above the 10% mark.

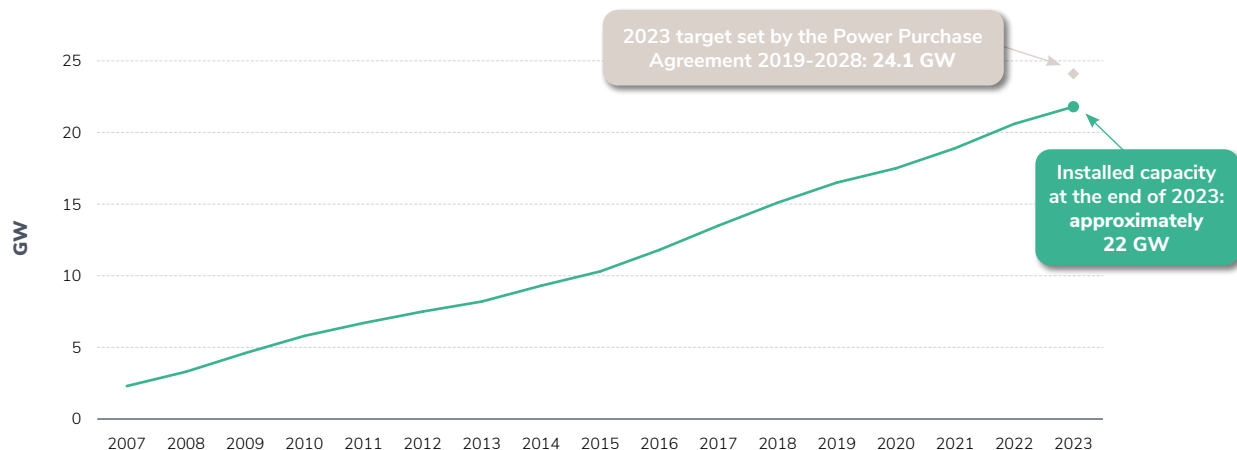
2.4.2 A slowdown in the growth of the fleet compared with the previous year, making it impossible to achieve the targets set by the public authorities for 2023

The power of the onshore wind power fleet stood at 21.8 GW at 31 December 2023, an increase in installed capacity of 1.2 GW compared to 31 December 2022.

Over the last five years, the average rate of development of onshore wind power has been around 1.4 GW/year, 25% less than the 1.8 GW/year that would have had to be installed between 2019 and 2023 to meet the targets for the end of 2023 set by the current Multiannual Energy Plan (PPE 2 covering the period 2019-2028), which targeted 24.1 GW of installed capacity for onshore wind power. The fleet at the end of December is therefore 2.3 GW below this target, corresponding to just over a year and a half of installations at the average rate observed over the last five years.

The wind power fleet will have to continue to develop to meet the challenges of decarbonisation of end-use consumption and reindustrialisation set by the public authorities⁴⁴. The speech given by the French President in Belfort in February 2022 confirmed the desire to continue developing the onshore wind fleet while at the same time adapting it by establishing the principle of levelling out over time the achievement of development targets (with the prospect of doubling capacity by 2050

Figure 2.16: Onshore wind farm development and comparison with public targets by 2023

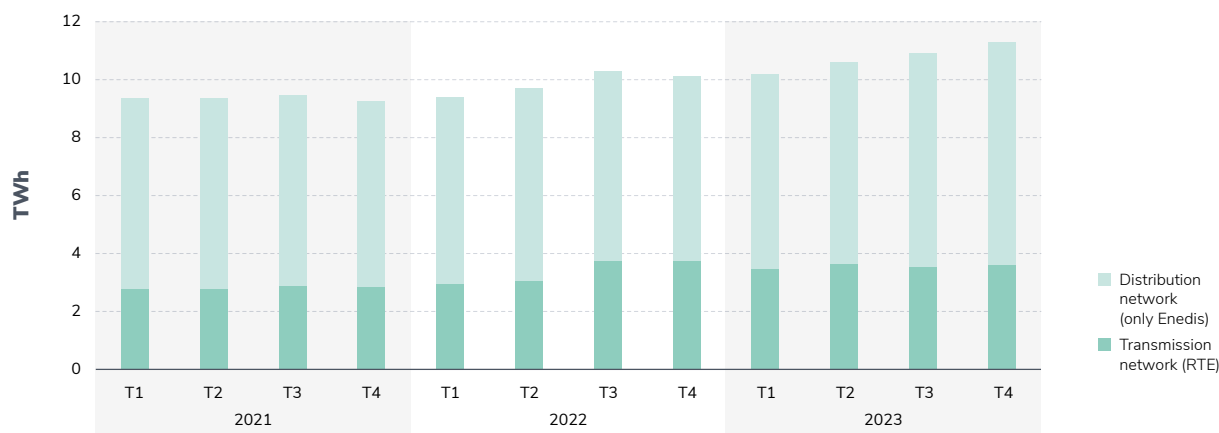


42. RTE, Change in wind power load factor, 2024

43. Average annual rate calculated as the average of coverage rates at 30-minute time intervals.

44. The analyses detailed in RTE's "Bilan prévisionnel 2023-2035" (Generation Adequacy Report) show that the development of renewable energies is one of the essential levers for achieving the decarbonisation and reindustrialisation objectives over the period.

Figure 2.17: Capacity of onshore wind power projects under development, by quarter, on the electricity transmission network (RTE) and the distribution network (Enedis scope only)



instead of 2030). This reflects both a desire to continue development and a slowdown in the pace of commissioning over the next few years.

It is in this vein that the consultation document for the French Strategy for Energy and Climate (SFEC), published in autumn 2023, outlines a review of the pace of development of onshore wind power in France, with less ambitious medium-term targets for onshore wind power and, in return, higher targets for offshore wind power. For onshore wind power, the consultation document proposes an extension of the trend of installation seen in recent years, as well as approximate ranges for installed capacity, ranging from 33 to 35 GW by 2030 and 40 to 45 GW by 2035.

The volume of onshore wind power projects in advanced development phase⁴⁵ increased in 2023: it reached 11.3 GW⁴⁶ as of 31 December, compared to 10.1 GW in the same period in 2022. This increase, of about 1 GW, is close to that observed

in 2021 and could signal a slight increase in the rate of annual installation of new capacities in the coming years. However, the latter is not guaranteed: the actual time taken to commission a project can vary, as can the time spent on development. In addition, the increase in volume observed since 2021 remains modest compared to the overall volume of projects in development.

2.4.3 The wind power capacity installed in France remains lower compared to those of European neighbours

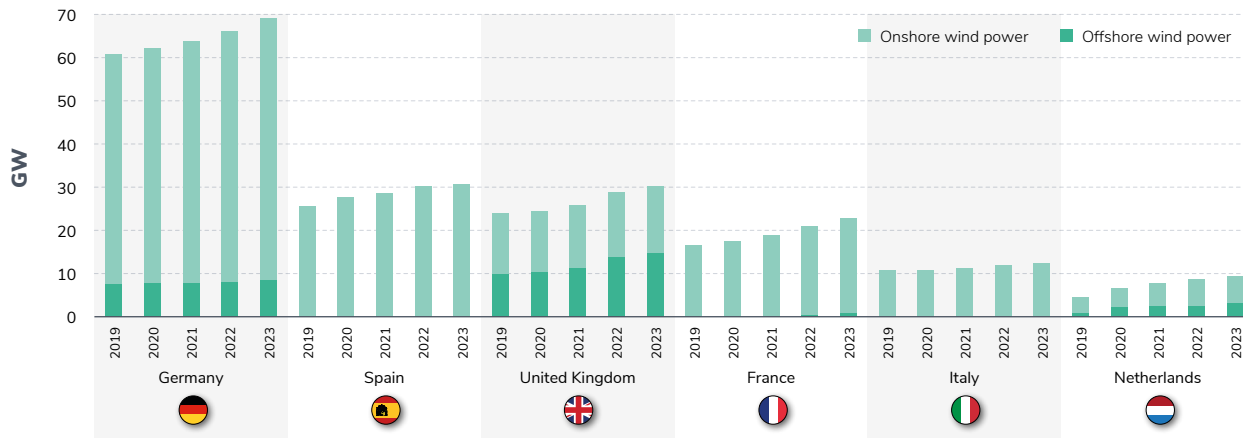
The French wind power fleet (onshore and offshore) stood at 22.7 GW at the end of 2023 and remains significantly smaller, in total capacity, than that of some neighbouring countries such as Spain (30.7 GW), Germany (69.5 GW) or the United Kingdom (30.2 GW). The latter two countries are also ahead of the game in the development of offshore wind power⁴⁷, with respectively 8.5 GW for Germany and 14.7 GW for the United Kingdom.

⁴⁵. For the RTE network, these are projects which have been the subject of a "queue entry proposal" or an accepted "technical and financial proposal", or which have been selected as part of an invitation to tender. For the Enedis network, these are projects for which a connection request has been deemed complete by the distribution network operator.

⁴⁶. RTE data on the transmission network, and ENEDIS data on the distribution network. – [Enedis, Projects in development – Current requests by power tranches and injection methods – Cumulative histories, 2024](#)

⁴⁷. Whose load factor is higher on average than that of onshore wind power, see *Offshore wind power* section

Figure 2.18: Wind capacity trends in a selection of European countries (data at the end of 2023 except for the United Kingdom Q3 2023)



Sources: Fraunhofer Institute, REE, RTE, BEIS UK, TERNA, CBS and ENTSO-E

In 2023, the rate of installation of new onshore wind capacity increased in Germany (3.0 GW, +48% compared with 2022) and the UK (0.8 GW in the first three quarters, +130% compared with 2022 over this period), while it remained stable in Italy (0.5 GW) and decreased in France (1.2 GW, -30% compared with 2022) and Spain (0.6 GW, -60% over the year). Offshore wind capacity installed in 2023 will be lower than in 2022 for all these countries. In the case of offshore wind power, capacity increases are not continuous but depend on the commissioning dates of each new offshore wind farm, which produces an incremental increase over the year of commissioning. Even greater increases are expected for France in 2024, with more than 0.6 GW of offshore wind capacity, corresponding to the completion of the Fécamp and Saint-Brieuc wind farms at the start of the year. The latest proposals for development rates up to 2030, most of which are provisional as they are still in the consultation phase and have yet to be validated by the parliaments of the various countries, point to significant potential increases

for wind power in Germany (10 GW/year for onshore wind power and 3 GW/year for offshore wind power), Spain (5.5 GW/year for onshore wind power) and the UK (5 GW/year for offshore wind power), compared with France (1.5 GW/year for onshore wind power and 0.3 GW/year for offshore wind power⁴⁸).

According to the figures for the production source⁴⁹, 2023 was a record year for installations in the European Union as a whole, with 17 GW installed, bringing total capacity to 221 GW. This represents a very slight acceleration compared to 2022, which saw around 16 GW of installations, albeit that the pace remains insufficient, depending on the source, to achieve the European Union's climate and energy objectives for 2030. The year 2023 was also characterised by a record in terms of new installed capacity for a single wind farm, due to the installation in the Netherlands of the "Hollandse Kust Zuid" offshore wind farm, currently the largest in the world, with a capacity of 1.5 GW⁵⁰.

⁴⁸. According to the first guidelines of the French Strategy for Energy and Climate (SFEC) made public in November. These trajectories, however, foresee a clear acceleration for the offshore wind source from 2030, at around 3 GW/year (see the Offshore wind section).

⁴⁹. WindEurope. *The EU built a record 17 GW of new wind energy in 2023 – wind now 19% of electricity production, 2024*

⁵⁰. This wind farm also has the distinction of having been built without any public subsidies.

2.4.4 The guaranteed tariff continued to generate revenue for the French government in 2023

The majority of wind and solar power generation benefits from an incentive remuneration system thanks to a guaranteed tariff that supports the development of these sources⁵¹. The difference between this guaranteed tariff (feed-in tariff or reference price obtained by the producer, according to criteria set by the French government) and electricity market prices is borne by the government. It may be positive from the government's point of view, i.e. represent revenue, if wholesale market prices (spot or forward) are higher than guaranteed prices, or negative, i.e., represent financing of production by the government, in the opposite case. In 2022, this mechanism generated revenue for the French government for the first time, as wholesale electricity prices⁵² were, on average, higher than guaranteed tariffs. In 2023, this trend continued and was amplified by the increase in production volumes and forward prices set in 2022 for the year 2023.

An initial estimate by CRE on 3 November 2022 for the reassessment of public service energy charges, based on the situation observed at the height of the energy crisis, indicated that onshore wind power should bring in €8.9 billion in 2022⁵³. This estimate was based on a forecast of the profits or losses made by sales of renewable electricity generation on the forward and spot markets. It is therefore naturally subject to updating in line with new price forecasts on these markets, or to re-evaluation a posteriori in line with actual prices. The CRE's deliberation of 13 July 2023⁵⁴ on the assessment of public service energy charges for 2024 indicates that onshore wind power finally brought in €2.3 billion in 2022, and that it should still bring in €3.9 billion⁵⁵ and €3 billion respectively in 2023 and 2024, for a total of €9.1 billion for the period 2022-2024. By way of comparison, such an amount represents 79% of the subsidies received by the production source via the mechanism of the Contribution to the Public Electricity Service (CSPE) over the last 20 years⁵⁶. As explained above, these estimates for 2023 and 2024 are provisional and may be updated.

51. Via the Complementary Remuneration or Obligation to Purchase mechanisms. Producers can also sell directly to a consumer or supplier through the signing of a long-term private law contract ("Power Purchase Agreement"). Although this type of contract is on the increase, it remains largely a minority phenomenon today.

52. In the spot and futures markets.

53. CRE, *CRE's deliberation of 3 November 2022 on the reassessment of public service energy charges for 2023, 2022*

54. CRE, *CRE's deliberation of 13 July 2023 on the assessment of public service energy charges for 2024 and the reassessment of public service energy charges for 2023, 2023*

55. Revenues for 2023 could be higher than those for 2022 due to the combination of two opposing effects: while profits from the sale of wind power generation on the spot market were lower in 2023 than in 2022, profits on the forward markets were higher in 2023 than in 2022, in particular, because the price at which energy was traded on these markets was set in 2022, at a time when energy prices were very high.

56. CRE, *Annex 7 of the CRE's deliberation of 13 July 2023 on the assessment of public service energy charges for 2024 and the reassessment of public service energy charges for 2023 – History of public service energy charges, 2023*

2.5 Two new offshore wind farms to be built by 2023 and increased medium-term targets

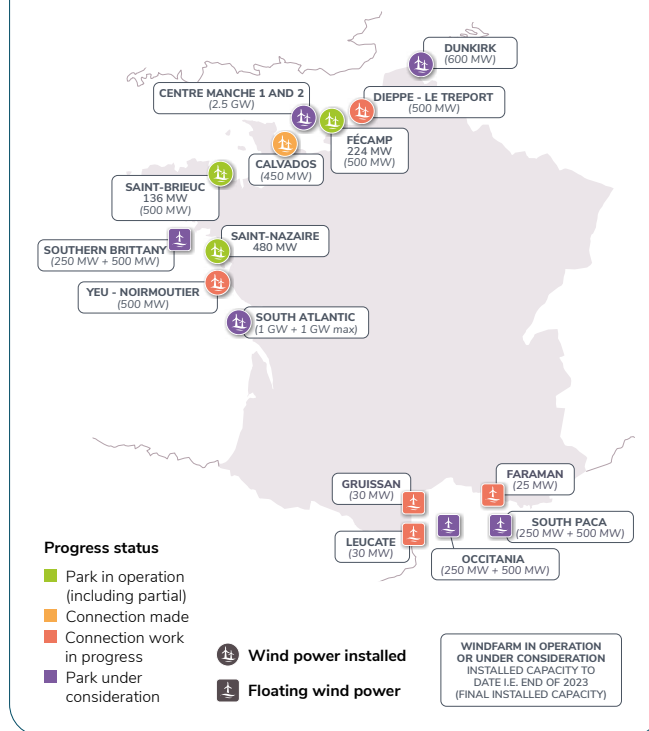
2.5.1 The construction of two new offshore farms began in 2023

The year 2023 saw the gradual commissioning of two new offshore wind farms in France, located off the coasts of Brittany and Normandy, near Saint-Brieuc and Fécamp. With the first farm commissioned in 2022 off Saint-Nazaire, France now has three offshore wind farms in operation, two of which are currently being finalised. When the installation of the two new farms is completed, the total capacity of offshore wind power in mainland France will reach 1.5 GW. As of 31 December 2023, capacity connected to the network represented around 224 MW for the Fécamp wind farm and 136 MW for the Saint-Brieuc wind farm (i.e., 45% and 27% respectively of their total future capacity), bringing installed offshore wind capacity to 840 MW.

When completed, the Saint-Brieuc wind farm will comprise 62 wind turbines installed on the seabed, 16.3 km from the coast at the nearest point, with a total installed power of 496 MW. The Fécamp wind farm will comprise 71 wind turbines located between 13 and 24 km off the coast⁵⁷, for a total installed capacity of 497 MW.

In the Multiannual Energy Plan 2019-2028, the public authorities set a target for offshore wind power of 2.4 GW of capacity in service by 2023. Even if the total capacity planned for the three wind farms mentioned above were taken into account, the installed capacity would reach approximately 1.5 GW, still nearly 1 GW below this target. Several other wind farms, each with a capacity of around

Figure 2.19: Map of existing and planned offshore wind farm projects at the end of 2023



500 MW, are expected to come on stream in the short term: by 2025, the Courseulles-sur-Mer (450 MW) and Yeu Noirmoutier (496 MW) wind farms are due to be completed, followed in 2026 by the Dieppe - Le Tréport (496 MW) wind farm.

The volume of energy generated by offshore wind farms represented 1.9 TWh in 2023. This was mainly due to the Saint-Nazaire wind farm, as the production volume of the two new wind farms was low over the year due to their gradual commissioning.

⁵⁷. As of 31 December 2023, both wind farms are still in the process of being installed. While some wind turbines are up and running and are already generating electricity, others are still under construction. Both farms are expected to be fully operational in the winter of 2023-2024, according to the operators.



FOCUS

A higher target for installed capacity in 2035

In recent years, offshore wind power has emerged as an essential technology for achieving France's energy and climate objectives. Offshore wind power is now economically competitive, and a significant part of its value chain is located in France. As a result, the industry enjoys broad political support, even though there are some areas of concern, particularly with regard to conflicts of use at sea and the preservation of marine biodiversity. In 2022, the offshore wind pact signed between the French government and the wind energy industry will significantly raise development targets. The latter targets around 40 GW of offshore wind power by 2050 and provides for an intermediate objective of 18 GW

of installations commissioned in 2035. New announcements during 2023 also concerned a possible increase in the target for 2050 from 40 to 45 GW. In the short and medium term, this clear acceleration is reflected in the initial guidelines submitted for consultation in November 2023 as part of the new French Strategy for Energy and Climate, which propose a target of 3.6 GW in 2030 and 18 GW in 2035. The planned fivefold increase in installed capacity in just five years, between 2030 and 2035, represents a major challenge, requiring major planning efforts that must be anticipated and implemented over the next few years, in particular with the launch of several invitations to tender for new capacity⁵⁸.

2.5.2 A higher load factor at sea

While the load factor of onshore wind turbines installed in France is around 23-24% and can reach around 26% for the most recent wind turbines⁵⁹, offshore wind turbines generally have a significantly higher load factor, which can be explained by several structural factors: they take advantage of a surrounding area at sea free of obstacles and stronger and regular winds. They are also larger, with higher mast sizes and rotor blade diameters.

As with a land-based site, the exact load factor for an offshore wind farm depends on the site selected and the average annual winds found locally. It also depends on the manufacturing technology of the wind turbines used. In 2023, the Saint-Nazaire farm, in its first year of operation⁶⁰,

achieved an average annual load factor of 35%. This level is lower than the average load factor of 40% announced by EDF, which corresponds to the long-term average that the farm should achieve over its entire life. The load factor over a particular year may vary depending on wind conditions and other factors (shutdowns for maintenance in particular), and it will take a sufficiently large sample of years to assess a reliable average load factor for this farm or other future farms.

According to the operator⁶¹, the Saint-Brieuc farm should produce 1,850 GWh annually, corresponding to a load factor of approximately 42%. This farm also marks a change in technology compared to that of Saint-Nazaire, with wind turbines of higher unit power (8 MW and 6 MW respectively).

⁵⁸. For more details on the subject, refer to chapter 3 Electricity generation and storage of RTE's "Bilan prévisionnel 2023-2035" (Generation Adequacy Report).

⁵⁹. See the note Change in wind power load factor on the RTE Analytics and Data portal.

⁶⁰. Which is not representative of "normal" operation since it may involve tests, adjustments for optimisation or shutdowns for maintenance. In particular, a large part of the farm was at a standstill in December, a time of year when the farm usually produces a lot of power.

⁶¹. Ailes Marines, *An overview of the project, 2023*

By the end of the decade, according to the operators, the other expected wind farms will have even higher load factors. For example, for the Dunkirk and Centre Manche 1 offshore wind farms, the project developers who have responded to the

various invitations to tender envisage load factors of almost 50%⁶². Over the same time horizon, floating wind farms will also be able to enjoy better offshore winds, which will help improve their load factor.

62. For Dunkerque, the developers indicate an annual operating time at full power of between 3,950 and 4,150 hours, i.e., a load factor of between 45% and 47% ([CRE, Dunkerque summary report, 2023](#)). For Centre Manche 1, the load factor would be between 48% and 51.8% ([CRE, Centre Manche 1 public version summary report, 2023](#)).

2.6 A record volume of solar power generation and an unprecedented increase in the installed fleet

2.6.1 Solar output is on the rise

Solar power generation was 21.6 TWh in 2023, an increase of 17% (+ 3.1 TWh) compared to 2022.

The increase in production is primarily due to the increase in the installed solar power fleet, which has accelerated since 2021 (see the next section).

The load factor is down very slightly and was 14.2% in 2023 compared to 14.5% in 2022. The rate of coverage of consumption by solar power generation averaged 5.0%⁶³ in 2023, breaking the 5% barrier for the first time, against a backdrop of falling consumption in France.

Figure 2.20: Change in annual photovoltaic solar power generation volume between 2009 and 2023

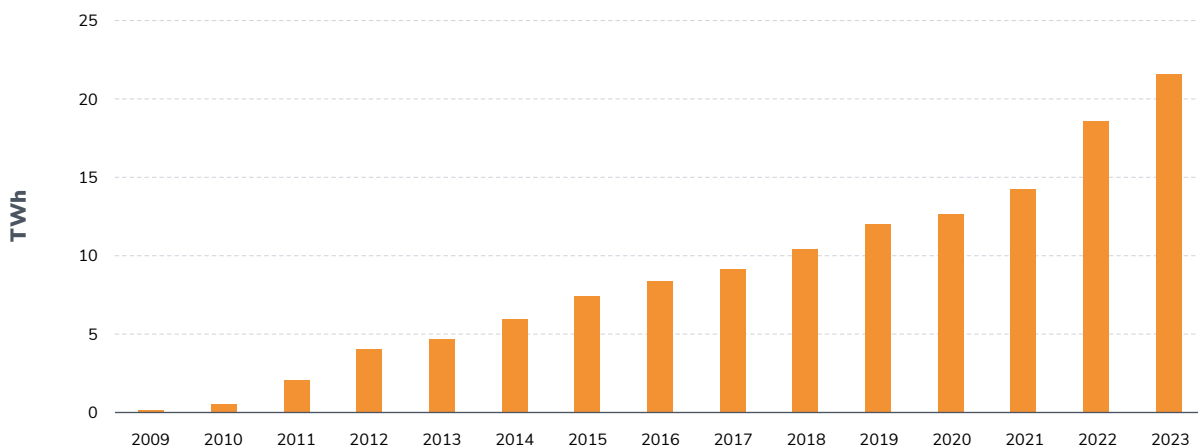
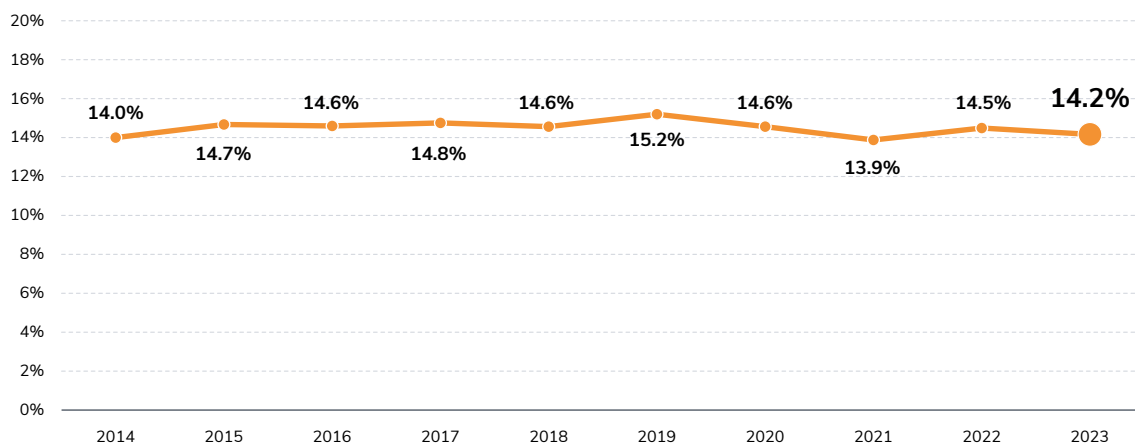


Figure 2.21: Change in annual photovoltaic solar power load factor between 2014 and 2023



63. Average annual rate calculated as the average of coverage rates at 30-minute intervals.

2.6.2 An acceleration in the pace of development, making it possible to move closer to the targets set by the public authorities

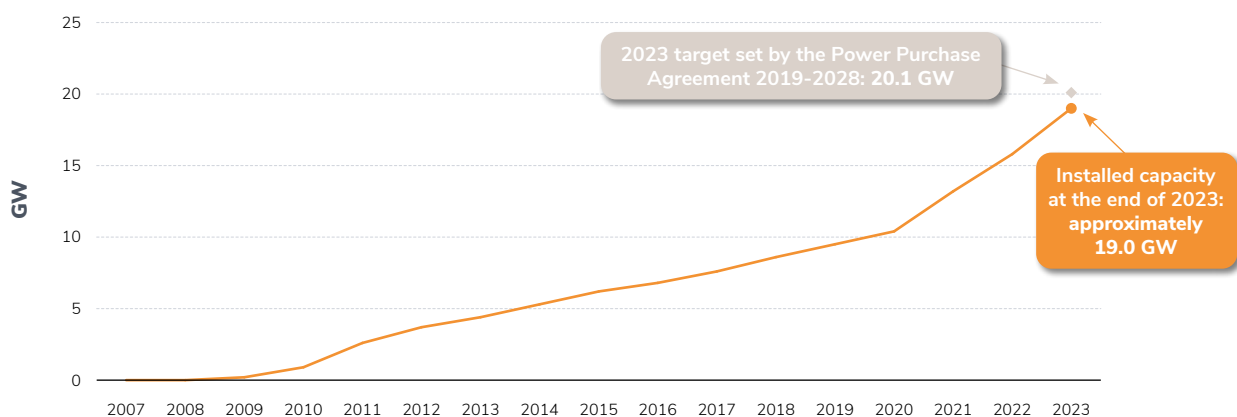
The solar power fleet reached **19.0 GW** at the end of 2023, an increase in installed capacity of **3.1 GW** compared to the end of 2022^{64,65}. This change in installed capacity represents a record development over one year, with a net acceleration compared to the previous rates observed in 2021 and 2022 (+2.7 GW/year).

Thanks to this significant growth in the fleet, the installed fleet is close to the target of 20.1 GW set by the Multiannual Energy Plan (PPE) 2019-2028 at the end of 2023 to within about one gigawatt, which is about six months behind the average rate of installation seen over the last five years. Over the period 2019-2023, i.e., the first period of the PPE, the rate of development observed (2.1 GW/year) was 10% lower than the rate that would have been necessary to achieve the objectives (2.3 GW/year).

However, the increase in the fleet observed on average since 2021 (2.9 GW/year) largely exceeded this rate, marking a clear improvement compared to that of 2019 and 2020 (+0.9 GW/year).

Over longer horizons, the solar power fleet will have to continue to develop to meet the challenges of decarbonisation of end-use consumption set by the public authorities⁶⁶. The first guidelines of the French Strategy for Energy and Climate (SFEC), submitted for public consultation in the autumn of 2023, propose an increase in long-term targets, which would imply a marked acceleration in the pace of photovoltaic development in mainland France. It also indicates the first possible ranges of installed capacity, respectively 54 to 60 GW in 2030 and 75 to 100 GW in 2035. These targets would represent development rates of between 5 and 7 GW/year approximately by 2035, more than twice the average rate of the last three years.

Figure 2.22: Growth of the photovoltaic solar power fleet and comparison with public targets for 2023

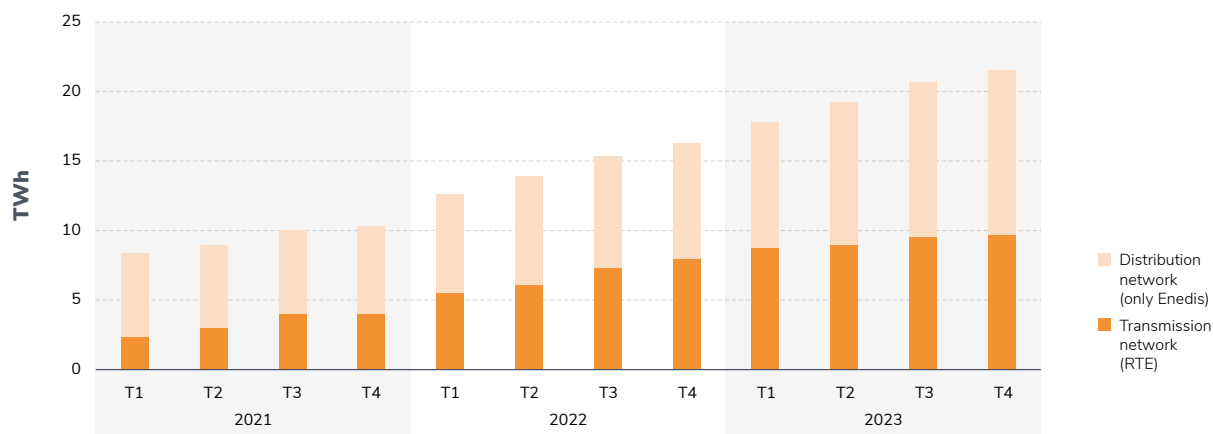


64. The installed capacity at the end of 2022 (15.9 GW) has changed slightly compared with the figure given in the 2022 Electricity Report (15.7 GW) due to the changeover to definitive data.

65. It should be noted that self-consumption installations without injection are not counted in the fleet and production. Self-consumption installations with injection are counted in the fleet, but only injected production is taken into account. These types of installations have grown significantly this year, although they still represent only a small share of the total solar power fleet. – [Enedis, Production fleet – Regional & departmental – Cumulative history, 2024](#)

66. RTE's "Bilan prévisionnel 2023-2035" (Generation Adequacy Report) indicates that the development of renewable energies is one of the essential levers for achieving the decarbonisation and reindustrialisation objectives by 2030-2035.

Figure 2.23: Capacity of photovoltaic solar power projects under development, by quarter, on the electricity transmission network (RTE) and the distribution network (Enedis scope only)



As in 2022, the volume of solar projects in development⁶⁷ in 2023 increased significantly, reaching more than 21 GW at the end of 2023⁶⁸ compared to about 10 GW at the end of 2021, a doubling of the volume of projects in development in less than two years. Annual growth in installed capacity is therefore likely to increase significantly over the next few years, even if it is not possible to predict precisely when and to what extent, as the actual commissioning time will depend on the type of project, legislation and the local context.

2.6.3 A widening gap in the pace of development compared to neighbouring countries

The rate of installation of the photovoltaic fleet accelerated markedly in 2023 in France and in some of the neighbouring countries. Compared to 2022, this pace accelerated in Spain (+12%

increase in pace) and France (+16%), and accelerated significantly in Germany (+91%), Italy (+112%) and the United Kingdom (+260%, in the first three quarters alone). This dynamic did not allow the French fleet to reduce the gap with the German, Spanish and Italian fleets, these countries also having installed a greater power in absolute value (respectively 14.3 GW, 5.2 GW⁶⁹ and 5.2 GW over the year) but it enabled the UK fleet to pull ahead. The total capacity available at the end of 2023 in Spain (25.1 GW⁷⁰), Italy (30.3 GW) and in particular in Germany (81.8 GW), and the Netherlands (22.6 GW) are therefore significantly higher than the French capacity (19.0 GW) (see also the Europe section).

For the European Union as a whole, the figures for the production source⁷¹ indicate a record installation in 2023, with 56 GW more installed capacity

67. For the RTE network, these are projects which have been the subject of a "queue entry proposal" or an accepted "technical and financial proposal", or which have been selected as part of an invitation to tender. For the Enedis network, these are projects for which a connection request has been deemed complete by the distribution network operator.

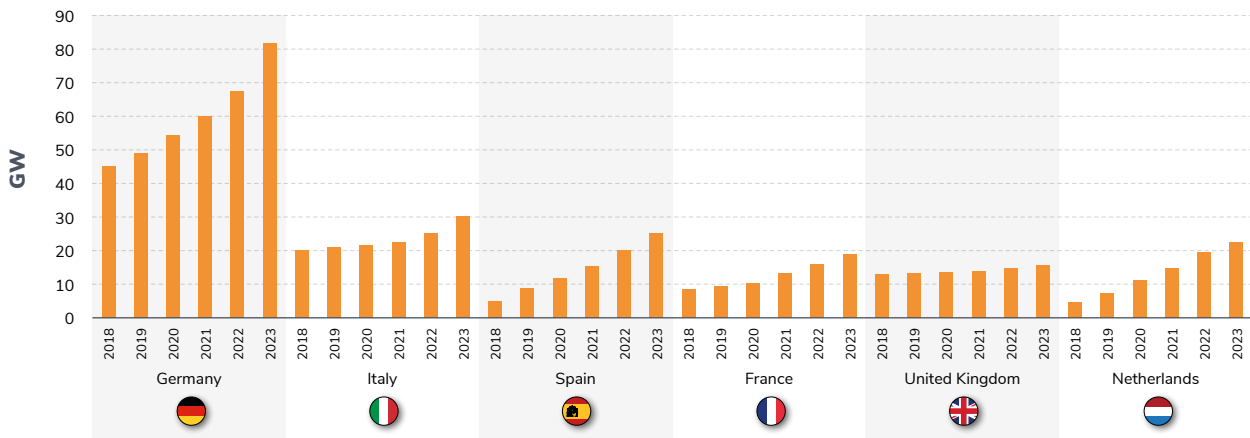
68. RTE data on the transmission network, and ENEDIS data on the distribution network. – [Enedis, Projects in development – Current requests by power tranches and injection methods – Cumulative histories, 2024](#)

69. The figures for Spain do not take into account private and industrial self-consumption installations, which represent +1.7 GW of installations in 2023, according to the industry. – [UNEF, En 2023 se instalaron en España 1.706 MW de autoconsumo fotovoltaico, 2024](#)

70. The figures for Spain do not take into account self-consumption installations by private individuals and industry, which have developed very strongly in recent years (7 GW by the end of 2023, according to the industry). – [UNEF, En 2023 se instalaron en España 1.706 MW de autoconsumo fotovoltaico, 2024](#)

71. [SolarPower Europe, EU Market Outlook for Solar Power 2023-2027, 2023](#)

Figure 2.24: Photovoltaic solar power capacity trends in a selection of European countries (data at the end of 2023 except for the United Kingdom Q3 2023)



Sources: Fraunhofer Institute, REE, RTE, BEIS UK, TERNA, CBS and ENTSO-E

for the year (+ 40% compared with 2022), bringing the total capacity of the fleet from 167.5 GW to 263 GW (+27% in one year). The previous record was set in 2022 (40 GW) and the industry expects a continuous acceleration over the coming years. The trend could therefore continue, with more installations each year than the previous one at the

European level, at least until 2030. A significant part of the installed capacity in Europe in 2023 was in Germany (14.3 GW⁷² out of 56 GW): Germany therefore installed in a single year the equivalent of 75% of the total photovoltaic fleet existing in France at the end of 2023.

72. Fraunhofer Institute figures.

2.7 Thermal production from renewable sources and waste remained stable

The renewable thermal and waste production source includes electricity generation facilities from solid biomass (wood, straw, etc.), waste (household and paper) and biogas. While a large proportion of the electricity produced by the source is considered renewable (from solid biomass or biogas), only 50% of the electricity produced by household waste incineration plants is considered renewable, by convention⁷³.

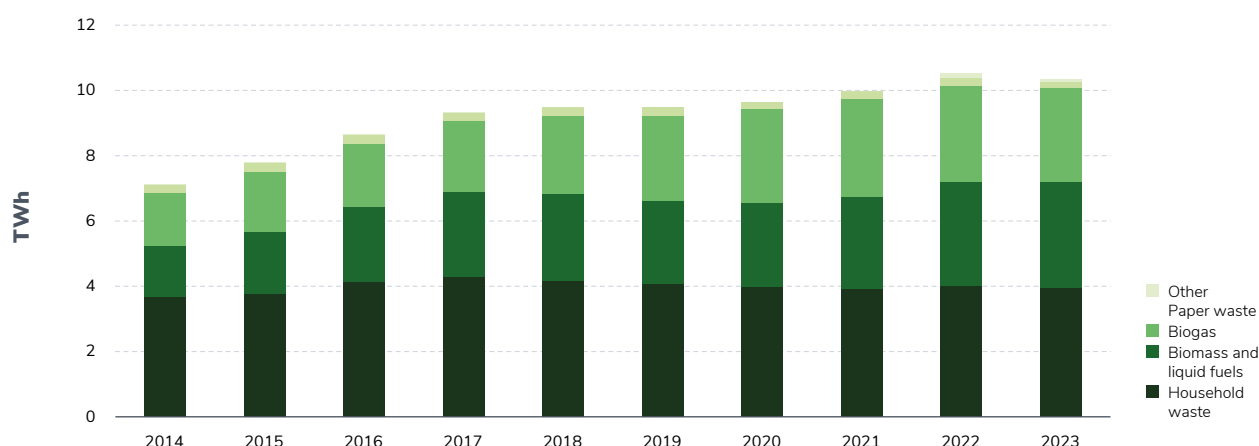
The volume of electricity generation from bioenergy and waste remained stable in 2023 compared to the previous year, at 10.4 TWh (compared to 10.5 TWh in 2022). This is due to the stability of the fleet in service compared with 2022 (2.2 GW) and to the fact that this fleet produces electricity “in baseload”, i.e., on a continuous and relatively constant basis, often as part of cogeneration units.

The installed capacity had increased steadily during the 2010s, from 1.2 GW in 2010 to 2.1 GW in 2020, a development driven almost entirely by biogas and solid biomass production units, but this increase has slowed significantly since 2020.

The consultation document for the French Strategy for Energy and Climate (SFEC), published in autumn 2023, provides guidance for the development of the production source in the coming years. The proposed trajectory continues the trend of recent years for biomethane and solid biomass, with a relatively stable stock for electricity generation due to the prioritisation of other uses for bioenergies, such as direct injection into gas networks, direct heat production for industry and buildings, and the production of biofuels for aviation and maritime transport.

As far as biogas is concerned, the SFEC’s consultation document forecasts the development of methanisation mainly for injection into gas

Figure 2.27: Renewable thermal production from waste between 2014 and 2023



73. Order of 8 November 2007 adopted pursuant to Article 2 of Decree No. 2006-1118 of 5 September 2006 on guarantees of origin for electricity generated from renewable energy sources or by cogeneration. – Légifrance (legifrance.gouv.fr)

networks. The use of biogas to generate electricity is essentially limited to units that are located far from the existing gas network, and therefore unable to operate with direct injection. The proposed targets rise from a range of 24 to 32 TWh of

biomethane produced in France by 2028, of which 14 to 22 TWh will be injected, to 50 TWh by 2030, but with 44 TWh injected, and therefore with a reduction in the proportion of biogas available for electricity generation.

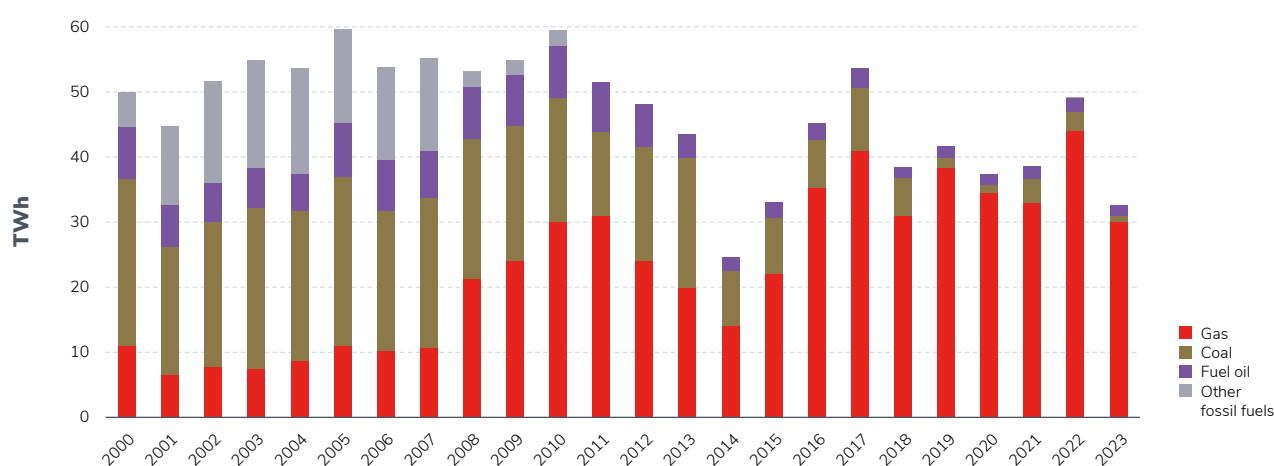
2.8 Fossil-fuel thermal production: the fossil-fuel thermal fleet has been used much less than in 2022, thanks to the recovery in nuclear and hydropower, the increase in renewable production and the fall in consumption

The contribution of fossil-fuel thermal production to France's electricity supply decreased significantly in 2023 (32.6 TWh) compared to 2022 (49.2 TWh), due to the improvement in the availability of nuclear and hydropower, the drop in consumption (see the Consumption section) and strong wind power generation (in particular in January, March, November and December). Looking at the longer-term trend, production from fossil-fuel units has not been this low since 2014. On average, the aggregate level of production of these sources has been lower over the last decade (39.4 TWh during the period 2014-2023⁷⁴) than that of the previous decade (53.3 TWh during the period 2004-2013), thanks in particular to the development of the wind power

and, to a lesser extent, the solar power sources. Furthermore, within this category, we can see the gradual replacement of coal- and oil-fired production by gas-fired production, which emits fewer greenhouse gases, as can be seen in the change in the volume of emissions linked to electricity generation (see the Emissions section).

Electricity generation from fossil fuels has a higher variable cost of production (cost of fuel) than other production sources, which is reflected in the price offered by these producers on the markets. In general, these sources are therefore "called upon" to produce after the decarbonised sources (renewable and nuclear), the variable costs of which are low (according to the principle of economic precedence or merit order, see the Price section). As a result, the annual volume of fossil-fuel thermal production is adjusted, on a European scale, according to the balance between electricity consumption and generation from decarbonised sources, within the limits of

Figure 2.28: Electricity generation from fossil fuels in France between 2000 and 2023⁷⁵



74. This remains true considering only the years prior to the health and energy crises: the average over the period 2014-2019 is also 39.4 TWh.

75. Between 2001 and 2007 inclusive, the "Other" series included production from distribution networks, production from derived gases and production from "miscellaneous" fuels. Between 2008 and 2010, it contained derived gases and miscellaneous fuels, while the production of distribution networks was divided between fuel oil and gas. From 2011, all the entities in the "Other" series have been broken down into the gas, fuel oil and coal series.

interconnection capacities. Over the course of 2023, lower electricity consumption and higher decarbonised production, both in France and the rest of Europe, meant that less production was needed compared with the previous year.

2.8.1 Gas-fired production in sharp decline

Electricity generation from gas-fired power plants decreased by about 32% in 2023 (30.0 TWh) compared to that of 2022 (44.0 TWh). It remained in high demand at the start of the year, against a backdrop of constrained hydropower generation, but at levels already seen in the past during the winter months. During the summer, production volumes were significantly lower than the previous year, approaching the averages seen over the years up to 2019, whereas in 2022 the contribution made by gas-fired power plants to the security of electricity supply during the summer, at the height of the energy crisis, was unprecedented.

Production then remained low over the last three months of the year (with a one-off rise in the

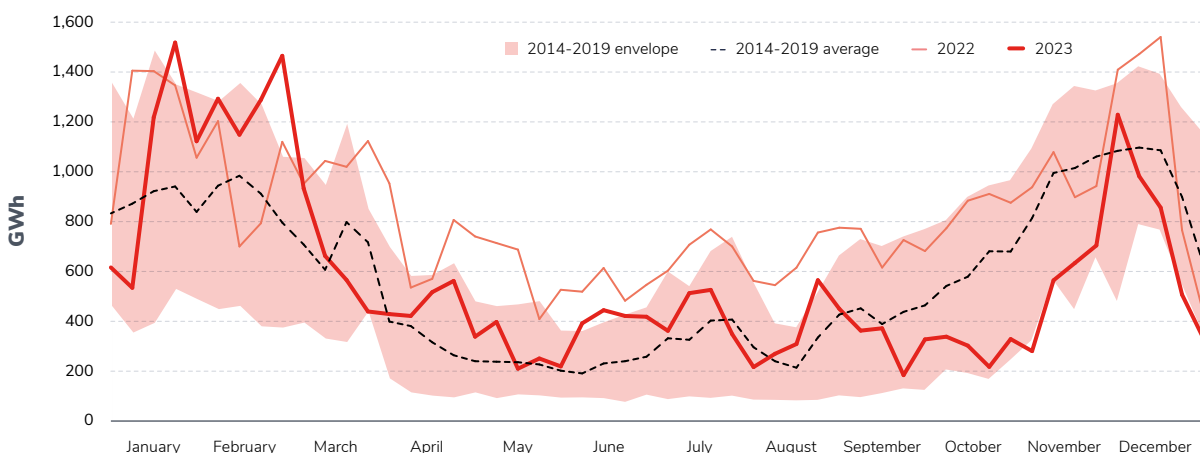
last week of November), against a backdrop of above-seasonal temperatures, relatively low consumption compared with historical levels, high volumes of hydro and wind power generation, and improved availability of the nuclear fleet compared with 2022.

2.8.2 Coal-fired production at an all-time low

The volume of electricity generated from coal was already extremely low in 2022 (2.9 TWh or 0.6% of production): it was even lower in 2023, reaching a level that is now insignificant in the generation mix (0.8 TWh, which corresponds to 0.17% of electricity generation in France). The level of production from coal-fired power plants was thus at an all-time low, almost twice as low as the already very low levels of 2019 (1.5 TWh) and 2020 (1.3 TWh)⁷⁶. The phase-out of coal in France is already almost complete in terms of volumes produced.

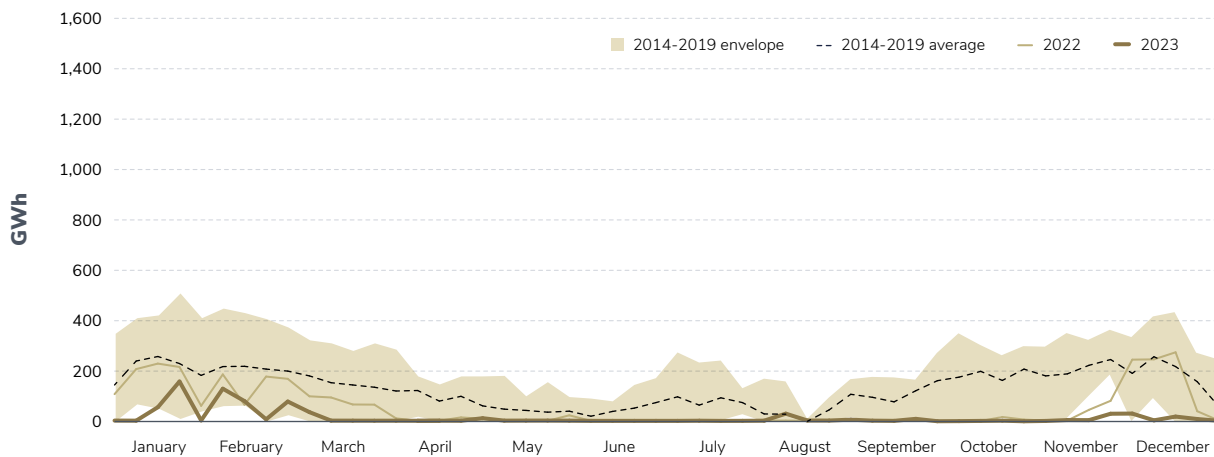
In detail, coal-fired power plants were called upon only occasionally during the year, mainly in the first few months, when the volume produced was

Figure 2.29: Weekly production of gas-fired power plants in 2023 and comparison with previous years



⁷⁶. A small part of this production, about a quarter, results from diffuse production injected into the network by industrial sites.

Figure 2.30: Weekly production of coal-fired power plants in 2023 and comparison with previous years



nevertheless lower than the previous year and the average for the years before 2019, and to a lesser extent at the end of the year, when the high level of wind power generation and the low level of consumption meant that there was very little need to use coal, even occasionally.

The low level of production observed in 2023 reflects the gradual decline in the number of coal-fired power plants in France in recent years (closure of the Gardanne and Le Havre power plants in 2021). Emissions associated with these power plants remained well below the permitted threshold, including before the cap was raised⁷⁷.

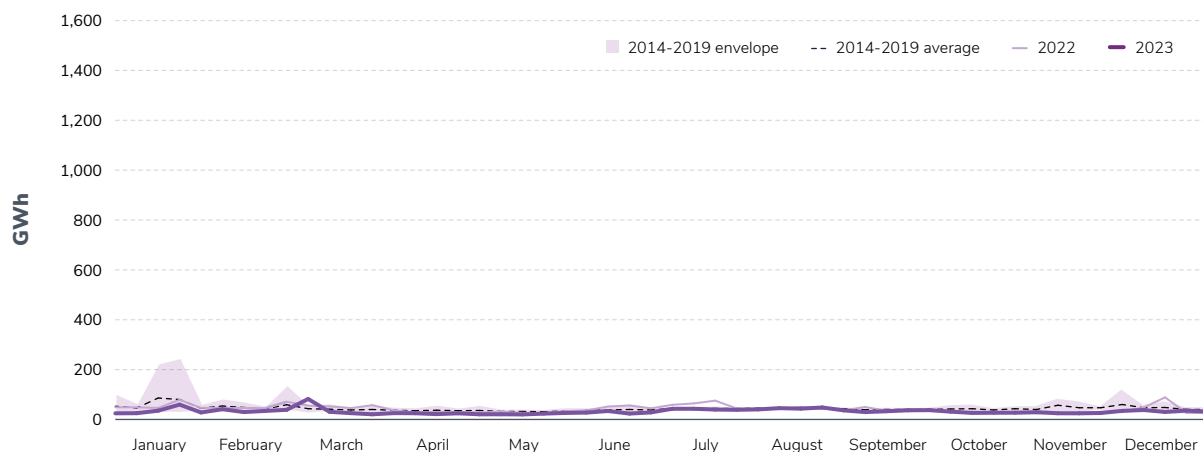
⁷⁷ Article D311-7-2 of the French Energy Code, which set a greenhouse gas emission threshold from 1 January 2022 for power plants with an emission factor greater than $0.55 \text{ t}_{\text{CO}_2\text{eq}}/\text{MWh}$, had been amended by several decrees to set higher thresholds until the end of 2024.

2.8.3 Fuel oil production has remained very low in the last few years

Electricity generation from fuel oil represented 1.7 TWh for the year 2023, or 0.3% of total production. This volume is down compared to the level reached in 2022 (2.2 TWh) as well as compared to pre-crisis levels. Fuel-oil production facilities were called upon on a relatively regular basis during the year, with some occasional peaks in the first months.

As for coal-fired power plants, the volume of greenhouse gas emissions from fuel-oil-fired production facilities was very much lower than the ceilings in force in 2023 defined by Article D311-7-2 of the French Energy Code, and even lower than the levels expected before the regulatory ceilings were raised. It should be noted that the total annual electricity generation of fuel-oil-fired power plants was already of this order of magnitude before the establishment of the regulatory ceilings.

Figure 2.31: Weekly production of fuel-oil-fired power plants in 2023 and comparison with previous years

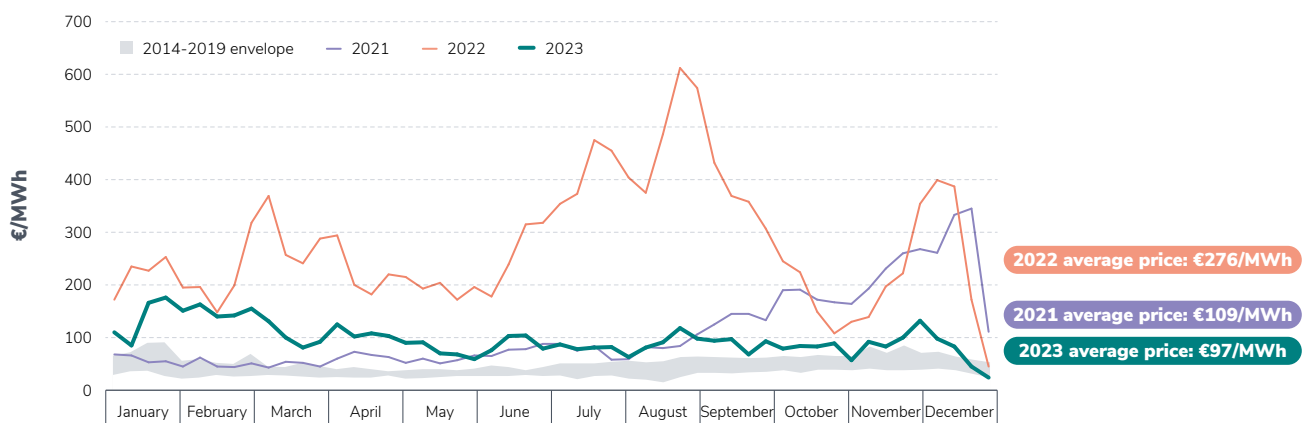


3. Electricity prices on wholesale markets have fallen significantly compared to 2022, but without returning to pre-crisis levels

In 2022, electricity prices reached unprecedented levels on wholesale markets, as a result of the triple energy crisis that simultaneously affected nuclear power generation in France, hydropower generation in southern Europe and gas prices following Russia's invasion of

Ukraine. In 2023, due to the improvement in nuclear and hydropower generation and the drop in gas prices, electricity prices showed a significant drop: from €276/MWh in 2022 to €97/MWh in 2023 as an annual average for "spot" prices.

Figure 3.1: Weekly average spot electricity prices in France in 2023 and comparison with previous years



Source: EPEX

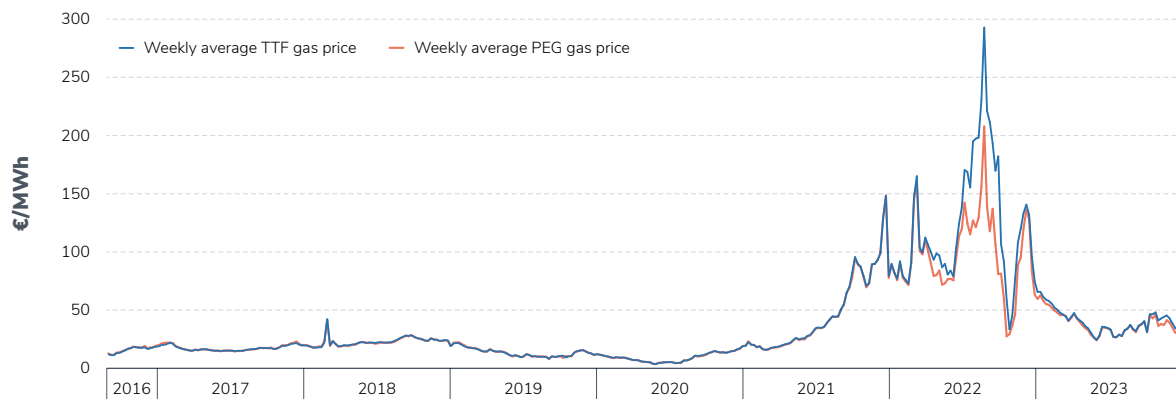
3.1 Market fundamentals improved significantly in 2023

The year 2022 was characterised by an exceptional increase in gas prices on the European market, which reached their peak in the summer. In fact, this increase continued a dynamic that began in the second half of 2021, before the start of the war in Ukraine. At the time, this upward movement was interpreted as the result of a mismatch between gas supply and demand due to the effects of the

economic recovery, which led to an increase in energy consumption as the Covid pandemic drew to a close against a backdrop of supply chains still disrupted by the crisis. It has now been established that supply restriction manoeuvres on the part of commercial operators linked to Russia have contributed to this increase, in particular by under-filling the stocks held by these players in Europe from summer 2021⁷⁸. The increase in gas prices had led to a comparable increase in prices on the wholesale electricity markets (spot and futures).

⁷⁸ The Oxford Institute for Energy Studies, *Falling like dominoes: the impact of Nord Stream on Russian gas flows in Europe, 2022*

Figure 3.2: Gas prices (GEP and TTF) between 2016 and 2023 (weekly averages)



Source: EEX

The crisis worsened in December 2021 with the pronounced deterioration in the availability of the French nuclear fleet, and then in 2022 with Russia's invasion of Ukraine. This had an effect on fuel markets, with an unprecedented rise in gas and coal prices driven by supply fears. Indeed, Russia supplied 42% of gas to the countries of the European Union in 2021: this share represented only 19% in 2022 and 9% in 2023. Gas prices on the French spot market thus reached a peak in August 2022 with prices above €200/MWh_{th}⁷⁹ on average over the month, and above €300/MWh_{th} over the last week, whereas in 2019, before the health and energy crises, they were around €20/MWh_{th} at the beginning of the year and €10/MWh_{th} at the end of the year. All these factors, combined with the unprecedented drought that affected Europe in 2022, reinforced fears about security of supply and led the European Union to adopt emergency measures to contain the rise in energy prices. These included measures specific to the power system (reduction of electricity consumption, taxation of infra-marginal income⁸⁰, etc.) and other measures concerning the gas market (reduction of demand, aiming to replenish stocks

before winter, etc.). These measures, which began gradually in 2022, have contributed to improving the determinants of security of supply in 2023.

The year 2023 was indeed characterised by a significant decline in fuel prices, which contributed to the decline in wholesale electricity prices: the spot prices of French gas fell below the €40/MWh_{th} mark on average over the year, whereas in 2022 the average was around €100/MWh_{th}. However, they remained relatively high compared to the values they had in the late 2010s.

The diversification of supplies has made it possible to replenish stocks more quickly, which had focused attention in 2022 because of their very low levels as winter approached. **On the one hand, stock levels were historically high at the end of winter 2022-2023, which proved to be warmer than normal seasons. On the other hand, LNG deliveries remained abundant in 2023 in line with 2022. Finally, gas consumption continued to decline in 2023, reaching a lower level than in 2022 in France (-13%⁸¹), and in the European**

79. Thermal MWh indicates the energy content of the gas, before conversion to electricity.

80. This is the income that producers receive due to the difference between the market price (based on the marginal cost of the last unit called, often a gas-powered unit) and their variable cost of production.

81. Energy Networks Open data. Gross daily consumption

Union (-10%⁸²). As a result, stocks reached the targets set by the European Union (90%) earlier than planned, in September 2023 instead of November. Fears about the security of the gas supply have thus been significantly reduced as the winter of 2023-2024 approaches.

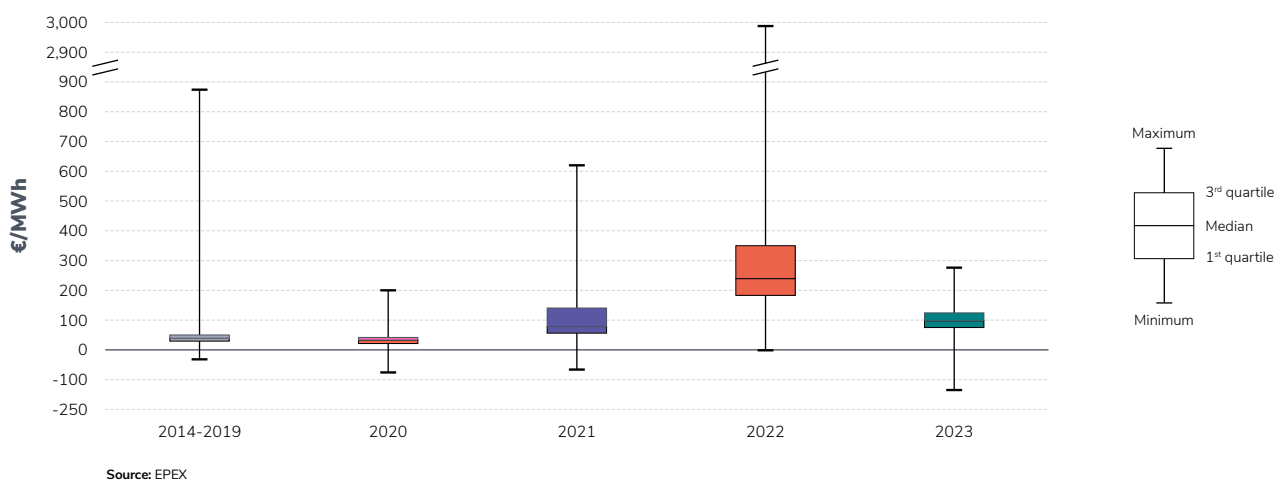
Other determinants of the security of the electricity supply showed a favourable trend in 2023, contributing to the fall in wholesale electricity prices: the unprecedented fall in consumption, which is largely an effect of high prices but also of above-normal temperatures, the improved availability of France's nuclear fleet, the rise in renewable production and rainfall that was within the norm (at least on average), which enabled hydropower stocks to be filled to capacity.

3.2 Spot prices have fallen significantly, but their volatility is more pronounced than before the crisis

As a result of the improvement in the determinants of the security of electricity supply, **the annual average spot price of electricity in France stood at €97/MWh in 2023, a division by three compared to the average price in 2022 (€276/MWh) and a drop of 11% compared to that in 2021.** Despite this significant decline, wholesale electricity prices have remained very high compared to levels in the years before the health and energy crises. Indeed, the average spot price over the period 2014-2019 was €40.7/MWh.

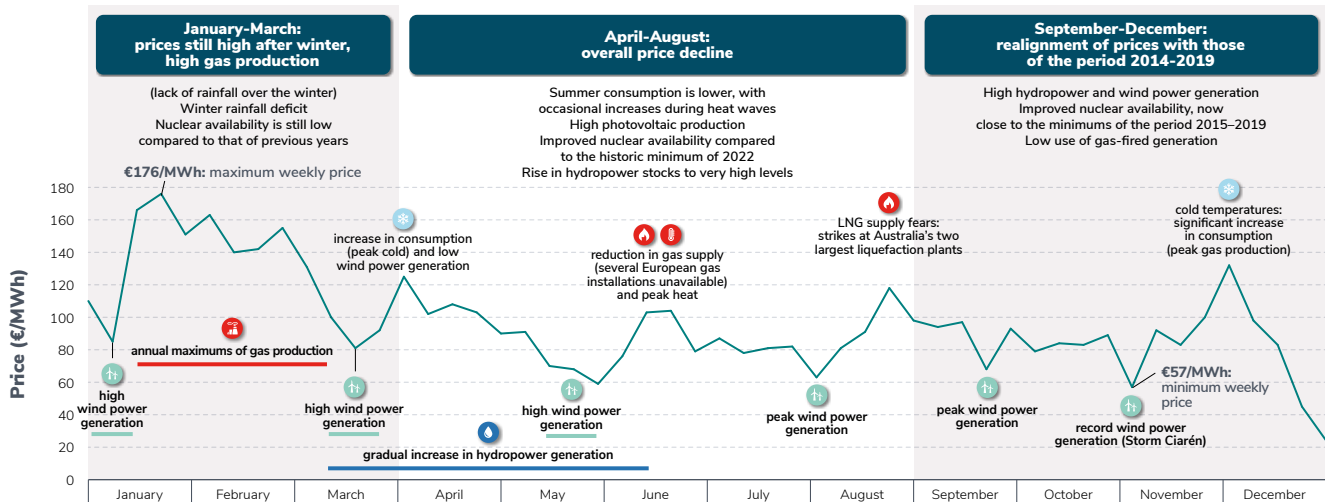
Looking at the development of prices during the year, the 2023 spot price curve has returned to characteristics similar to those of the pre-crisis years. The highest prices of the year typically occurred at the beginning and end of the year, when gross consumption was highest due to the winter period, unlike in 2022, when the greatest stresses on the power

Figure 3.3: Hourly spot electricity price distributions in France in recent years, and over the period 2014-2019



82. Eurostat, Supply, transformation and consumption of gas – monthly data

Figure 3.4: Weekly average spot prices in France in 2023 (weekends and holidays included)



system occurred exceptionally in the summer, resulting in a concentration of prices that were abnormally high for the period. On the other hand, the lowest prices were reached in late spring and summer when demand fell and renewable production held a more important place in the electricity mix.

In line with the general fall in prices, the hourly maximums recorded in 2023 are nothing like those in 2022 (prices had reached €2,713/MWh and then €2,988/MWh on Monday 4 April 2022) and also remained lower than the price peaks reached in the last few months of 2021. Prices were also less volatile in 2023, compared to 2022 and 2021, indicating less uncertainty about the security of supply. However, volatility remained higher than before 2020.

3.3 French spot prices are generally within the range of variable production costs for thermal facilities

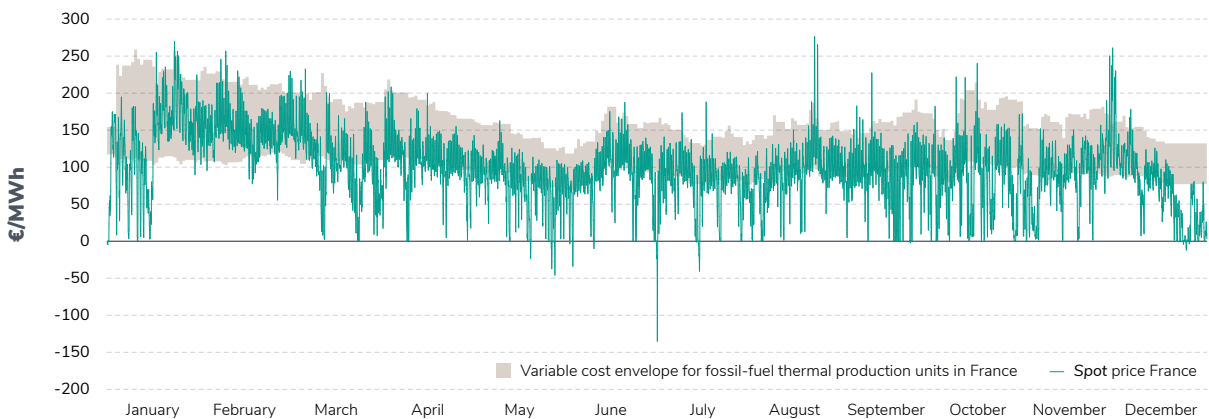
In 2023, as well as throughout the previous year, French spot prices very frequently fell within the range of variable production costs of thermal power

plants, including the cost of the corresponding carbon allowances. Prices have generally been set at the level of the operating costs of the marginal production units of the European power system, which have often been gas-fired production plants located abroad.

Thus, spot prices have reflected the volatility of gas prices, including during most of the peaks observed in March and during the summer of 2022. However, at the height of the crisis, in the summer of 2022, the price of electricity on the spot market occasionally reached levels of the order of €1,000/MWh, much higher than the marginal production cost of thermal units, even considering the high level of gas prices at the time⁸³. However, these prices can also be explained according to the marginalist principle, noting that the marginal units at the time regularly corresponded to power plants affected by stock constraints (oil-fired turbines, hydropower plants): these are operated on the basis of value-in-use, i.e. by arbitrating between immediate electricity generation (in the summer) or generation deferred over time (in particular the following winter, which is forecast to be very strained). This value-in-use management is a “normal” operating mode for

83. RTE, *Electricity report 2022. Price chapter, 2023*

Figure 3.5: Hourly spot electricity prices in France in 2023 and comparison with the variable costs of fossil-fired thermal power plants



stock resources, which helps to make the most of electricity stocks at the best time for the power system. In the second half of 2022, except for a few hours during the coldest hours of December, prices no longer reached summer values due to the decrease in electricity consumption from autumn 2022.

In 2023, due to the increase in renewable and nuclear power generation and the decrease in consumption compared to the previous year (consumption had started to fall significantly only from the autumn of 2022), the number of hours when prices fell below the variable cost range of thermal power plants increased. Prices were most often below this range between spring and summer and exceptionally during the first half of January, periods characterised by abundant renewable production

(wind power in winter and spring, solar power in summer) combined with a gradual improvement in the availability of the nuclear fleet. Gas production units have less often found themselves in a marginal position in the merit order, and have fixed the price less often. During the autumns and winters of 2022-2023 and 2023-2024, controllable thermal power units were more often used, as usual during this period, and prices remained more frequently within the range of variable costs for thermal facilities.

This price volatility on the spot market, which reflects the cyclical conditions of the balance between production and consumption, is not a problem in itself insofar as there are hedging markets for economic players to manage their supplies over the long term.



FOCUS

Market price and production costs

The specificities of the French generation mix create a structural misalignment between market prices, which are often fixed at the level of gas-powered units (often located abroad), and production costs, which are lower for low-carbon methods. This misalignment does not result from an “indexation” of prices to those of thermal production resources, but it is the result of market balances that are created at the European level. The European electricity market operates according to a logic of economic precedence (*merit order*), which leads the spot price of electricity to be formed every hour at the variable cost of production of the last unit called to cover demand⁸⁴. This is because producers have an incentive to start producing as soon as the market price exceeds their marginal cost of production (if the price is lower than the marginal cost of production, the producer will not be able to cover its costs, and in the opposite case, not producing would result in a loss of income). The surge in wholesale electricity prices led the Member States of the European Union to ask the European Commission for a structural reform of the European electricity market,

which was presented on 14 March 2023. This reform allows Member States who wish to do so to promote various tools, such as long-term contracts that can take the form of contracts for differences (CfD) or long-term bilateral commitments (*Power Purchase Agreements*, or PPAs). Alongside this work, a number of proposals for dealing with the repercussions of the crisis have stimulated public debate, particularly in France. Against this backdrop, on 14 November 2023, the public authorities presented a proposal for a system to protect electricity consumers, based in particular on the principle of taxing the income earned by EDF from its historic nuclear power plants, the precise terms of which were the subject of a dedicated consultation.

A more detailed discussion of the link between production costs and market prices and public interventions to stabilise prices paid by consumers over the long term will be presented in the Economics of the Electricity System chapter of RTE’s “*Bilan prévisionnel 2023-2035*” (*Generation Adequacy Report*), to be published in 2024.

84. In practice, market players optimise their purchases/sales at the level of their production and consumption portfolio, and not at the level of each individual unit, but the price still tends to form around the offer price of the marginal unit necessary to satisfy the supply-demand balance.

3.4 The spot price fell more sharply in France than in neighbouring countries, returning to its usual relative position within European prices

The functioning of the European electricity market, based on the principle of marginality (see the focus in the previous section), allows optimal use of the available production resources, within the limits of the capacities of exchanges between the different countries, and therefore minimisation of production costs at the level of the interconnected system.

The significant increase in market prices in France in 2022, as well as the reversal of exchange flows which led France to become an importer over the year, reflect the same need to resort to production resources abroad, which are more expensive than French units, in particular, to compensate for the low nuclear power generation due to checks and repairs linked to the phenomenon of stress corrosion cracking.

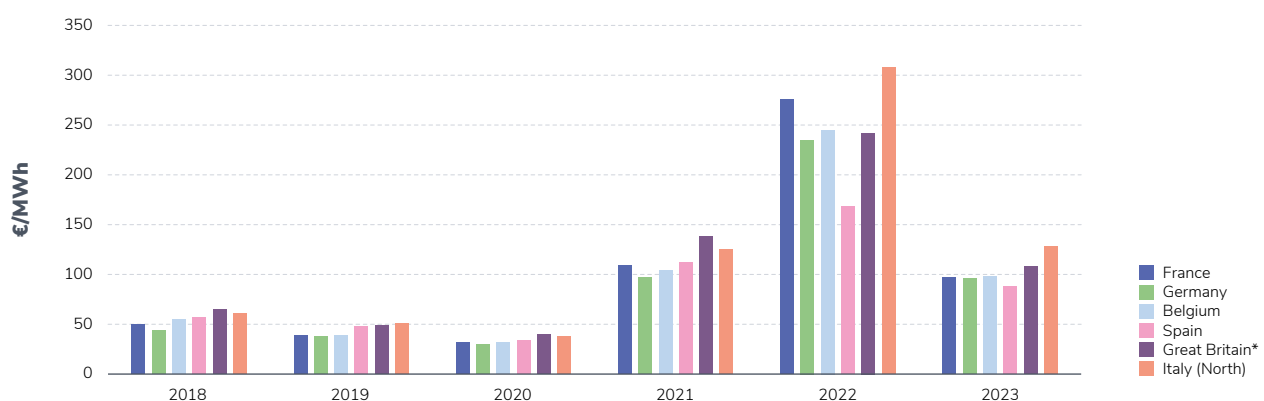
The easing of tensions on the French market in 2023, thanks to the improvement in low-carbon production, the decline in the level of consumption, and

that of gas prices, has reduced the need to request thermal resources abroad, and has allowed the spot price in France to return to lower levels than those of neighbouring countries. This has led to the reversal of the exchange balance, which has become an exporter again (see the Exchanges section).

The improvement in market fundamentals has also benefited other European countries, with a general decrease in spot electricity prices. While the French price went from €276/MWh to €97/MWh between 2022 and 2023, that is to say a 65% drop, the German, Spanish and Italian prices went from €235/MWh to €95/MWh (-60%) in Germany, from €168/MWh to €87/MWh (-48%) in Spain, and from €308/MWh in 2022 to €128/MWh (-58%) in Italy.

Thus, French spot prices have returned to their usual position in the European price hierarchy, becoming, on average, lower than prices in the United Kingdom and closer to prices in Belgium and Germany. Only in Spain have prices remained lower than in France, as they were in 2022, whereas they were historically higher until the end of the 2010s. The mechanism of capping⁸⁵ the price of

Figure 3.6: Annual average hourly spot electricity prices for several European countries over the 2018-2023 period

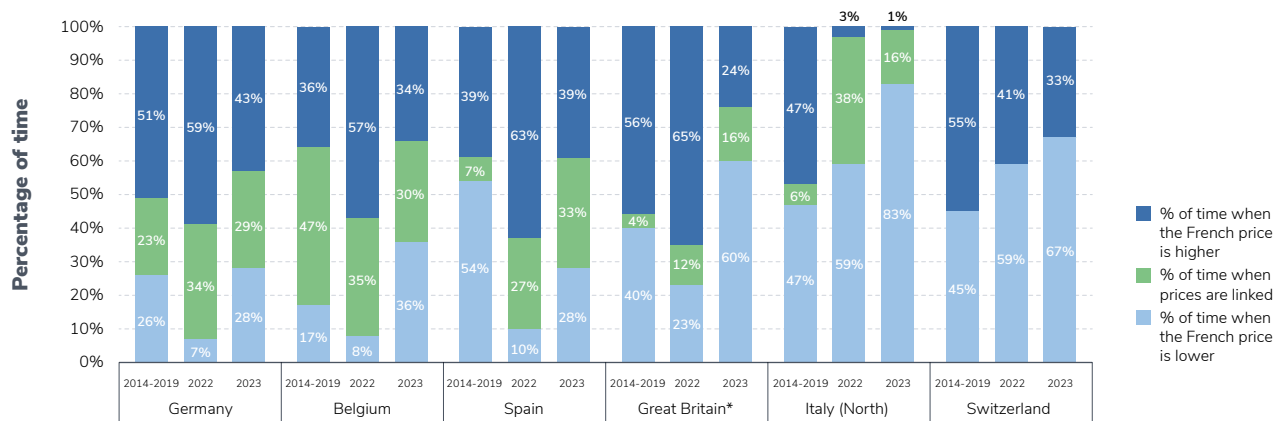


* Great Britain and Northern Ireland do not belong to the same market area: the data displayed here concern only Great Britain and not the United Kingdom.

Source: EPEX

85. Subsidy mechanism for thermal power plants (gas in particular) set up by Spain and Portugal. The rules of operation of the European market have continued to be applied by these two countries, but they have imposed a cap on the price of gas for electricity generation, granting gas-fired power plants compensation to cover the difference between this cap and the market price of gas. See the Economic analysis chapter of the "Bilan prévisionnel 2023-2035" (Generation Adequacy Report) for a discussion of this mechanism, which it would not be possible to transpose to France with the same effects, unless it were implemented simultaneously in all interconnected countries.

Figure 3.7: Positioning of the French spot price compared to that of neighbouring countries in 2022 and 2023, and comparison with the period 2014-2019



* Great Britain and Northern Ireland do not belong to the same market area: the data displayed here concern only Great Britain and not the United Kingdom.

Source: EPEX

gas used for electricity generation in Spain, which explained a large part of the difference observed in 2022, was renewed in 2023, albeit that this had no effect that year due to the drop in the price of gas below the cap set by the authorities. The abundant volume of renewable production in the country, linked in particular to the strong development of installed solar power capacity (+22% in 2023, see the *Europe* section), as well as consumption that is still below pre-crisis levels, explain the low level of prices in the country, the lowest on average among France's neighbours. If the pace of development of renewable capacities remains high, Spanish prices could become structurally lower than French prices.

In 2023, the proportion of time when the French price was lower than that of all neighbouring countries (Germany, Belgium, Spain, Great Britain, and Northern Italy) was 15%. By way of comparison, in 2022, this had happened only 4% of the time, whereas this rate was 25% between 2014 and 2019. With the development of renewable energies in neighbouring countries, it is likely that in the coming years average prices in these countries will be lower than in France more often than in the years up to 2019.

3.5 Structurally more frequent negative prices

The year 2023 was characterised, in France as in other European countries, by an increase in the number of negative price episodes on the spot market, the occurrence of which follows an upward trend over the last ten years, due to the significant increase in production capacity from renewable energies.

Negative prices can occur during times of low consumption combined with high renewable energy production. When renewable production exceeds consumption, controllable units, particularly non-flexible thermal units, should stop producing. However, temporarily shutting down a thermal unit can be costly because of technical and economic constraints (start-up costs, minimum technical requirements, minimum shutdown time, etc.), and it may be more advantageous for a producer to pay to continue producing for the duration of the period of high renewable production rather than shutting down the unit. In this case, producers are required to offer volumes of energy on the market at a negative price, reflecting the fact that they are willing to pay for buyers to consume (or resell to consumers) their production. Thus, consumers are paid to consume electricity produced in quantities that are

too abundant compared to consumption needs at these specific times.

Negative prices are not in themselves an anomaly in the functioning of the market. In theory, the negative price is a legitimate economic signal, encouraging consumers to increase their consumption during periods of high renewable production, and producers with controllable units to lower their production levels. In fact, however, only a small part of electricity consumption at a given time is covered by volumes traded at the spot price or whose price is indexed to it, which reduces the incentive effect of this signal on the level of consumption.

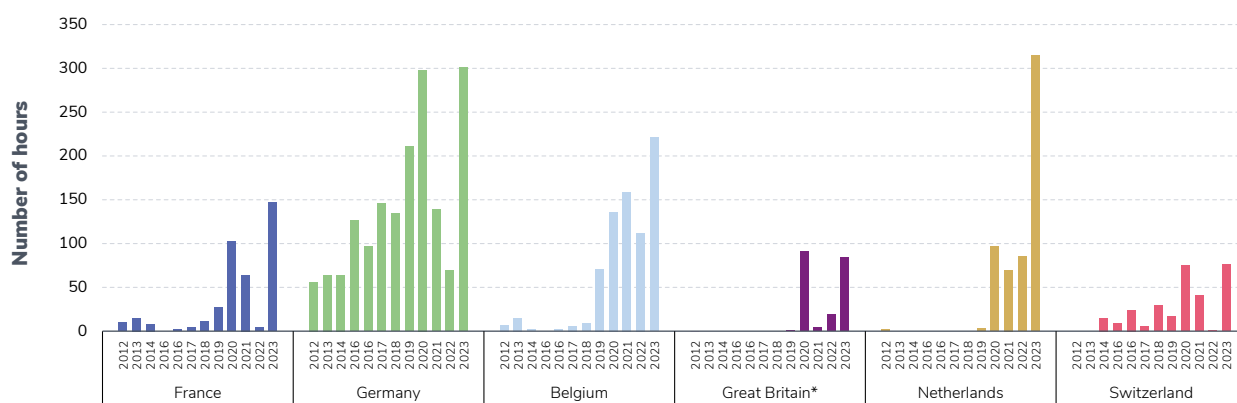
In addition, a large part of renewable production is also not exposed to market prices, having direct power purchase agreements through the feed-in tariff mechanism. The negative price does not then act as an incentive to reduce this production. On the other hand, facilities receiving additional remuneration have an incentive not to produce if prices are negative. Indeed, the mechanism does not provide for any remuneration during these episodes unless the number of hours the facility is shut down over the year exceeds a threshold defined for each production source (20 hours for wind power, for example).

In France, spot prices reached negative values for 147 hours in 2023, a historical maximum.

These negative prices appeared mainly between the months of May and September in the afternoon, between 12 p.m. and 4 p.m., as a result of high solar power generation and low levels of consumption during these periods. A significant episode occurred on 2 July: on that day, hourly prices fell to -€134.9/MWh, the lowest level observed since 2013, and the price was negative on average over the day, at -€1.2/MWh, which had not happened since 2020. The negative prices observed in France have often been the effect of bids submitted on the markets of neighbouring countries. Indeed, in the majority of cases where a negative price was reached in France, an even lower negative price was reached on the market of one of the other European countries at the same time. Prices tend to converge within the limits of trading capacities, which explains why a very negative price on the market of a neighbouring country is reflected in a slightly less negative price in France.

In the Netherlands, the number of negative price occurrences increased significantly in 2023 from just a few hours in 2019 to 316 hours in 2023. The development of solar and wind power generation capacities has been particularly rapid in the country, which has a target of 70% electricity from

Figure 3.8: Number of hours over the year when electricity prices were negative in a selection of European countries



* Great Britain and Northern Ireland do not belong to the same market area: the data displayed here concern only Great Britain and not the United Kingdom.

Source: EPEX

renewable energies in the electricity mix (see the Europe section). The proportion of these energies in the country's electricity mix has increased from 8% in 2015 to 40% in 2023. The solar power fleet particularly benefited from this acceleration. By way of comparison, the solar power capacity installed in the Netherlands is higher than the annual consumption peaks in the country. When renewable generation exceeds consumption and export capacities to other European countries are saturated (and, moreover, renewable production can be high in other countries at the same time), prices can reach very low negative levels. In particular, many solar power capacities are installed in private homes, which do not have the technical means or adequate incentives to adapt their injection into the electricity network in the event of surplus power generation⁸⁶. Thus, on Sunday 2 July, when solar power generation was abundant in several European countries, the price fell in the Netherlands to -€500/MWh between 1 p.m. and 3 p.m., a historical minimum.

Germany was also characterised by a record number of hours per year with a negative spot price in 2023 (301 hours). Unlike other countries, however, there is no marked difference from previous years. Indeed, this number is almost identical to that of 2019 (298 hours). The spot price reached a minimum level of -€500/MWh on Sunday 2 July

as in the Netherlands, the lowest since October 2009. In addition, over the period from Sunday 24 to Monday 25 December, 36 consecutive hours of negative spot prices were recorded. On this Sunday, followed by a public holiday during the end-of-year holiday period, temperatures were higher than normal for the season and wind power generation was abundant.

The temporal analysis of negative price episodes in the various countries makes it possible to identify common trends, in particular the fact that these mainly occurred during the spring and summer. In Germany, the winter months are also affected. The times when these prices most frequently materialise are during the afternoon consumption slump, between 12 p.m. and 4 p.m., and in some countries during the night consumption slump between midnight and 6 a.m.

All of this points to a need to develop flexibilities in the power system, and in particular a real move to scale in terms of demand flexibility, with the aim of adapting, both sustainably (to take account of solar power generation in the middle of the day, which is very regular and easily predictable) and dynamically (in particular to monitor wind power generation), the consumption profile to that of the renewable production (see the *Flexibilities* section).

⁸⁶. In particular, consumers with net-metering pricing contracts whose excess injection into the network is subsidised.

Figure 3.9: Monthly distribution, by year, of negative spot prices in France

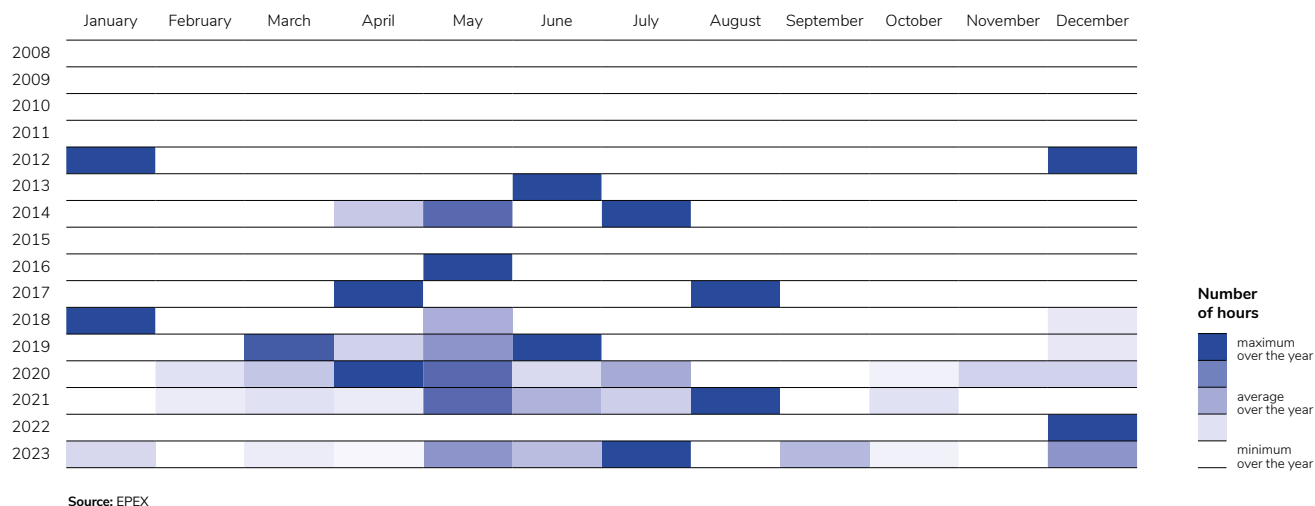


Figure 3.10: Monthly distribution, by year, of negative spot prices in Germany

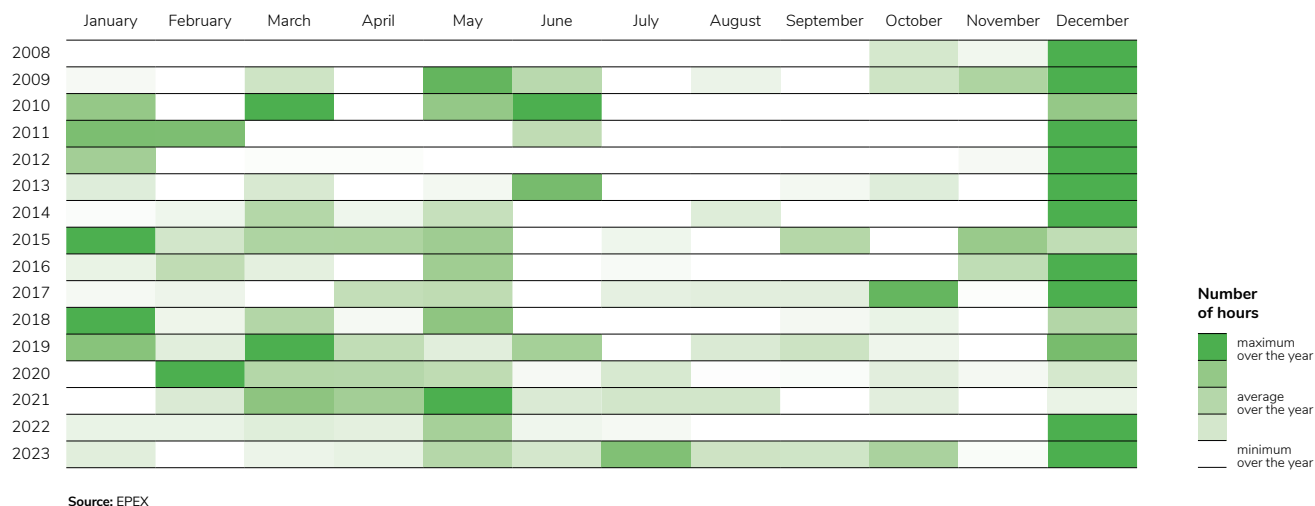


Figure 3.11: Monthly distribution, by year, of negative spot prices in the Netherlands

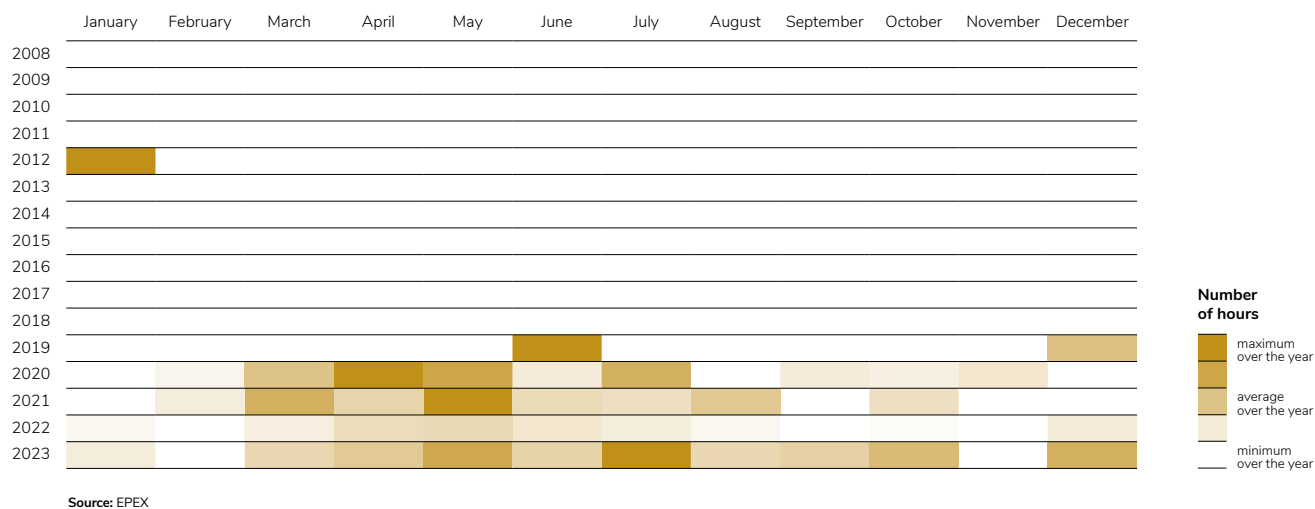


Figure 3.12: Hourly distribution, by month, of negative spot prices in France over the period 2002-2023

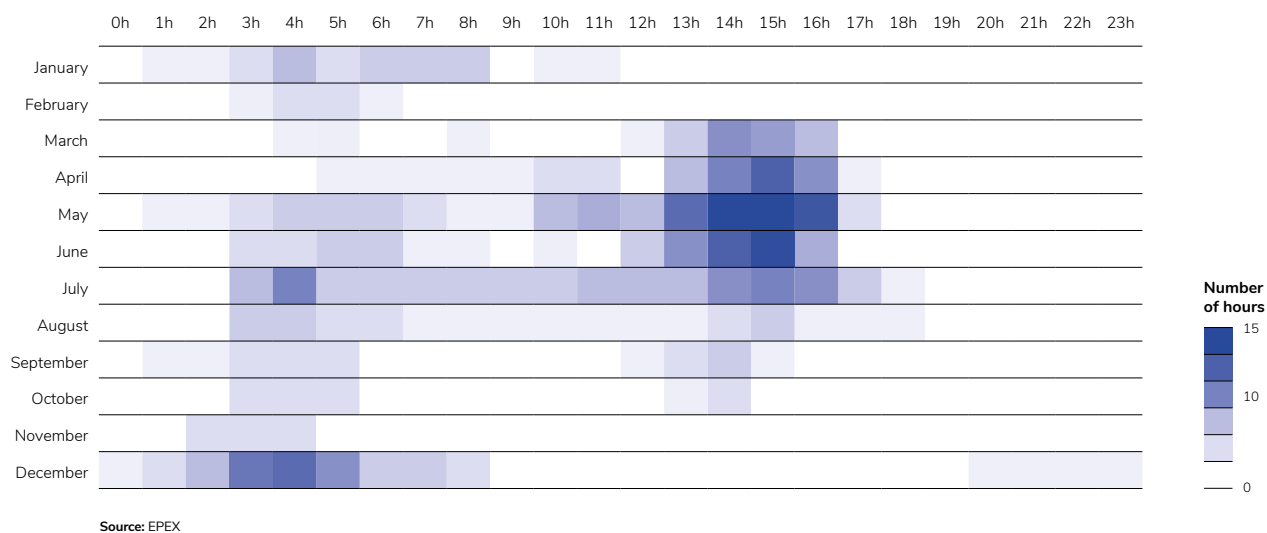
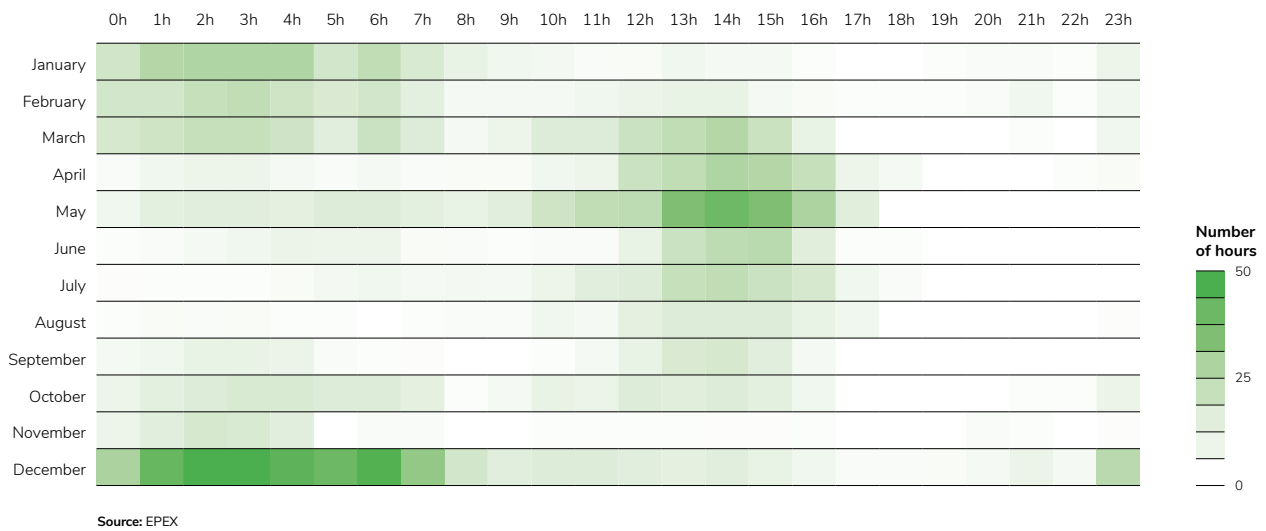
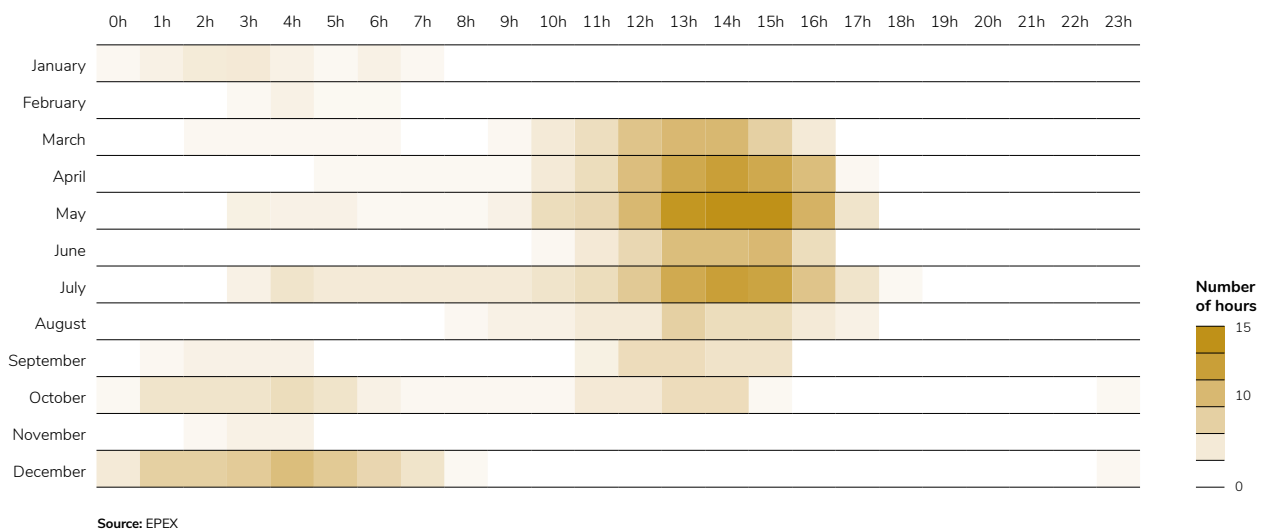


Figure 3.13: Hourly distribution, by month, of negative spot prices in Germany over the period 2002-2023**Figure 3.14: Hourly distribution, by month, of negative spot prices in the Netherlands over the period 2002-2023**

3.6 The risk premium for forward prices has decreased since the end of the summer

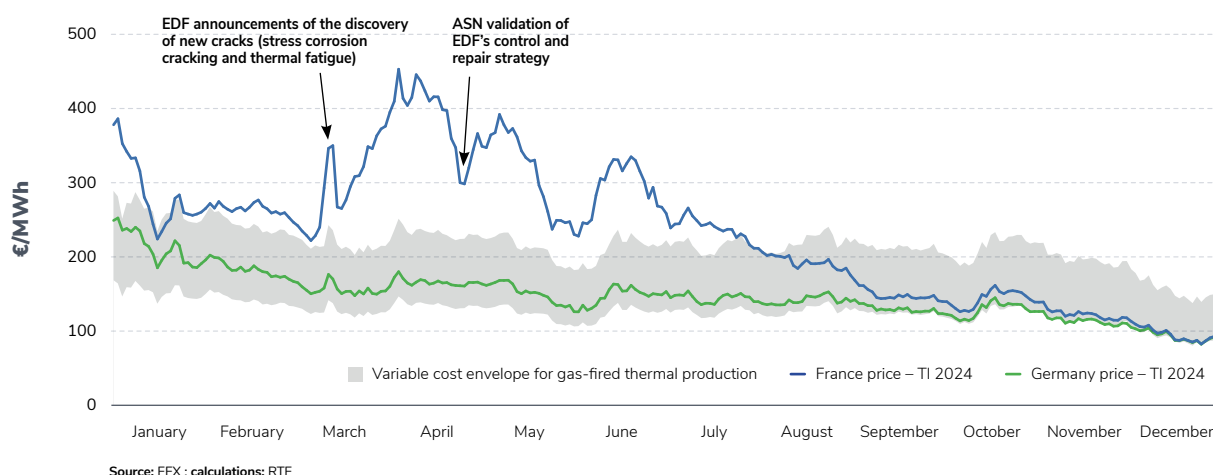
22. The less tense environment for gas and electricity supplies also benefited French forward prices. From mid-2021, the latter had reached unprecedented levels. While the average price of contracts negotiated in year N for an electricity delivery in year N+1 had remained relatively stable between 2014 and 2020, around €40/MWh, it stood at €122/MWh between June and December 2021 (for delivery in 2022) and at €366/MWh in 2022 (for delivery in 2023). In 2023, forward prices showed a clear decrease compared to the exceptional levels of 2022, with €162.7/MWh on average for a delivery in 2024, a decrease of 56%, while remaining well above historical levels.

The unprecedented rise in forward prices on the French market had not been solely the result of

tensions on the fuel markets and uncertainties over the security of electricity supply: since the second quarter of 2022, prices had included a risk premium that was decoupled from the economic fundamentals underlying the electricity markets, as highlighted by RTE in its various seasonal reports⁸⁷. It reflected the strong risk aversion of players and a hedge against extreme risk scenarios that appeared highly unlikely. In addition, the low liquidity of the electricity futures market in France has most likely exacerbated the rise in prices. On the one hand, a large part of the volumes consumed in France do not pass through the market⁸⁸. On the other hand, interconnection access rights and associated hedging products offer only a reduced visibility and possibility of long-term coverage for market players.

The exceptional risk premium characterising the French market had gradually decreased at the end of 2022. It was again visible between the spring and summer of 2023, after the detection of new defects on

Figure 3.15: Trend in 2023 of forward prices for delivery in the first quarter of 2024, in France and Germany, and comparison with the variable costs of gas-fired power plants



⁸⁷. RTE, *Analysis of the winter season 2023-2024, 2023*

⁸⁸. See the CRE's December 2022 report on electricity forward prices for the winter of 2022-2023 and the year 2023, its report on the functioning of the wholesale electricity and natural gas markets in 2022, and its public consultation of 12 October 2023 on the supply of the regulated electricity sales tariff for the year 2026 and the proper functioning of the wholesale market. The Cour des Comptes also pointed out that the ARENH system, which results in the allocation of electricity volumes outside the wholesale market, and the integrated nature of the incumbent operator, which uses most of its production to supply its own end customers, also contribute to a lack of liquidity in the French wholesale market (see report on the organisation of electricity markets, above).

welds repaired at the time of the construction of the reactors and identified as sensitive parts with regard to the phenomenon of stress corrosion cracking. At this time, the French price for delivery in the 1st quarter of 2024 was higher than the range of variable power generation costs for thermal power plants. The risk premium gradually disappeared from the end of the summer and throughout the winter of 2023-2024.

The prices of futures markets are of great importance in determining the prices paid by consumers. On the

one hand, they are reflected in regulated sales tariffs, and on the other, they directly affect consumers who buy from wholesale markets, in a differentiated way according to their terms of supply and the renewal date of their contract. Consumers whose contracts were up for renegotiation in autumn 2022 were particularly hard hit, as the prices offered by suppliers directly reflected forward prices at the time. Nevertheless, the price increase for consumers in France was relatively contained compared to other European countries.



FOR A BETTER UNDERSTANDING

Why can electricity prices depend on gas prices?

The European electricity market is based on the principle that the price of electricity is fixed at each moment at the level of the variable production cost of the last unit called upon to cover electricity demand. In other words, for each hour, everything happens as if the production facilities were “stacked” in order of economic merit until they reached a sufficient volume to supply the demand for electricity: the last facility called upon in this stack, described as “marginal”, then determines the price of electricity for the given hour. In practice, market players optimise their purchases/sales at the level of their production and consumption portfolio, and not at the level of each individual unit, but the price still tends to form around the offer price of the marginal unit necessary to satisfy the supply-demand balance. This ensures an economically optimal allocation of production.

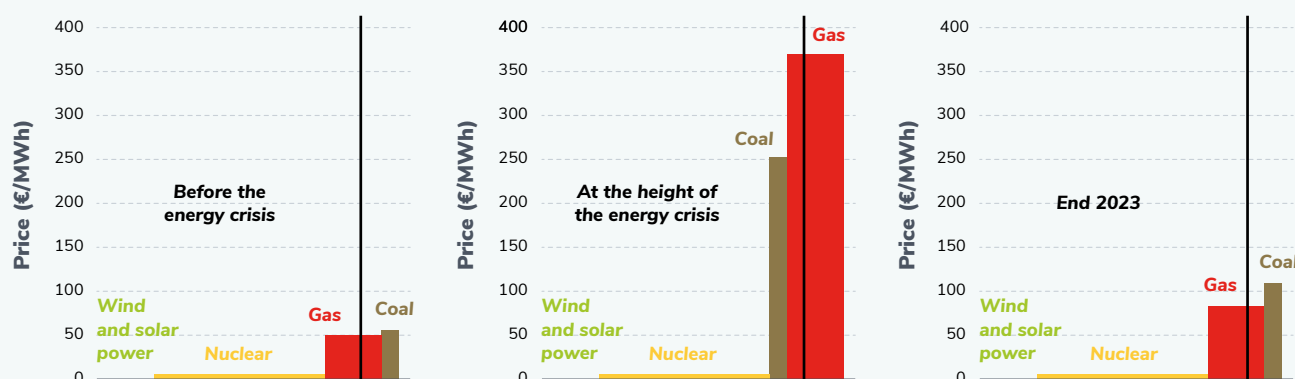
At the European level, this price formation mechanism takes into account the balance between

supply and demand in each price zone (which generally corresponds to a country), as well as the exchange capacity between these zones. The result is an optimisation, on a European scale, of the use of the resources available in the short term. As fossil-fuel thermal power plants are needed most of the time to ensure the supply-demand balance on a European scale, the hourly spot price is generally based on the variable cost of the corresponding production facilities, thus correlating electricity price trends with those of fuels such as gas and coal, as well as with the price of CO₂. So, even if the proportion of fossil-fired production in French electricity generation is low, it is still a determining factor in electricity pricing, because interconnection with the rest of the European grid means that electricity prices in France also depend on fossil-fired production located abroad and exchanged on the market.



FOR A BETTER UNDERSTANDING

Figure 3.16: Illustrative example of the order of economic precedence and electricity price formation: before the energy crisis, at the height of the energy crisis in 2022, and at the end of 2023



The different concepts of electricity prices (*spot, forward, etc.*)

In practice, the “electricity price” covers different concepts that are often confused. In particular, it is necessary to distinguish between the price of electricity on wholesale markets, on the one hand, and the “retail price” charged to the consumer, on the other.

The concept of “wholesale price” is itself multiple depending on the timeframe to which it refers: it can be either the spot price, corresponding to the price of one megawatt-hour of electricity for physical delivery at a given time, the day before for the following day (constructed on daily markets according to the principle of economic precedence illustrated above) or a few hours later (intraday markets), or a forward price with a longer delivery timeframe, ranging from one week to one year.

Futures markets allow producers and suppliers to hedge against the “price risk” of the daily market, i.e., against the hourly price volatility that forms there. The producers, on the one hand, and

the suppliers or large consumers, on the other, respectively sell or buy a large part of their production and consumption, to, as the case may be, define their margin or determine a rate for their customers, several months, or even several years upstream (with only a residual part of their production or consumption being sold or bought on the spot market).

Forward prices thus reflect a trade-off between selling or buying electricity in advance and waiting until the last moment to hedge (at the time of the daily market). Forward prices are therefore generally based on expectations of average spot prices, including a possible risk premium which may depend on the uncertainty and/or risk aversion of the various players involved. In particular, risk premiums can reach very high levels when a crisis occurs, reflecting players’ perceptions of a shortage or pressure on supply.

Forward prices are one of the components of the price of electricity paid by end consumers (they



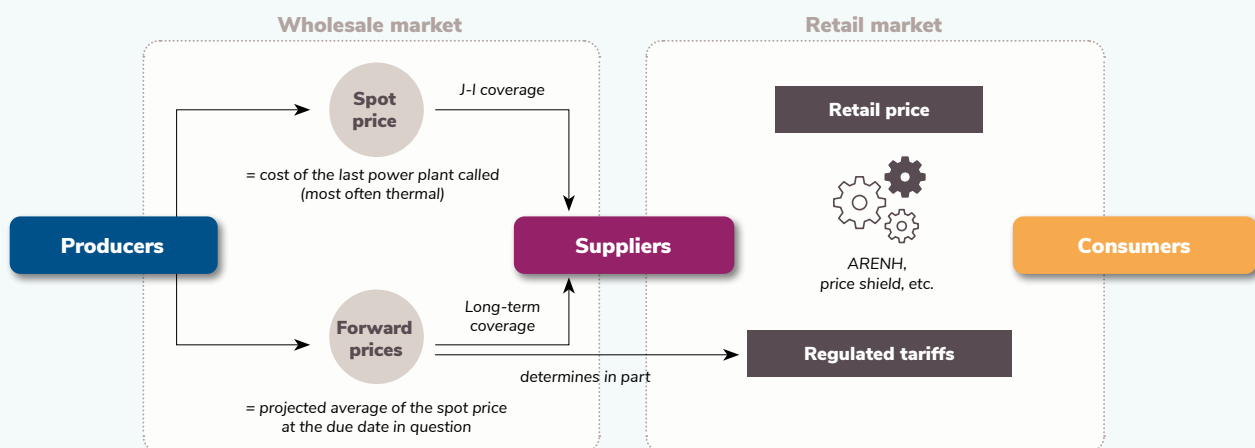
FOR A BETTER UNDERSTANDING

are used in particular to construct regulated sales tariffs and to supply consumers who are not eligible for these tariffs, such as industrial customers) alongside other components. In addition to this supply on the forward markets, the retail price shown on consumers' electricity bills includes a component corresponding to the costs of the network needed to transport the electricity, a tax component, a component linked to regulatory mechanisms such as the ARENH and other various components (marketing costs, capacity mechanism, etc.). These principles are common to

regulated sales tariffs, which are still largely dominant for residential and small business customers, and to the market offers that compete with them.

In short-term physical markets (daily markets – with next-day delivery – but also intraday markets), weather conditions play an important role. On the other hand, in the futures markets, which have a longer delivery date, prices are more strongly dependent on the outlook for gas prices over the medium term and the supply and demand situation.

Figure 3.17: Operation of the wholesale and retail electricity markets



4. France returned to its usual role as a net electricity exporter

4.1 Electricity markets have ensured optimal use of available resources

The power systems of the different European countries are now quite widely interconnected. Most countries in continental Europe are part of the “synchronous continental power system”, which shares the same 50 Hz electrical frequency at all times⁸⁹.

The development of interconnections has long been a priority of the European Union’s energy policy. Mentioned as early as 1955, this goal is considered a way to reduce the cost of electricity. The interconnection of national networks is indeed a prerequisite for the establishment of the European electricity market. By making it possible to take advantage of the complementarities of national energy mixes, it is likely to benefit the European community in three ways: by reinforcing the security of electricity supply and the operational security of interconnected systems, by reducing production costs on a continental scale through the use of the least expensive production resources, and by making it possible to integrate greater volumes of decarbonised energies.

Exchanges between European countries mean that the capacity needed for security of supply can be pooled, and the least expensive (and least carbon-intensive) production capacity available to cover electricity consumption in Europe can be called on at any given time. This pooling is particularly interesting because it makes it possible to take advantage of the consumption profiles in the various European countries. For example, consumption peaks do not occur at the same time of day or in the same season depending on the country (peaks in summer in the afternoon in Italy, in the evening

in winter in France, in the morning in winter in Scandinavian countries). To a lesser extent, this allows us to benefit from the abundant production of variable renewable energies.

The European electricity market helps to minimise the cost of operating the power system at the European level. However, the very high levels of electricity prices reached in 2022, which exerted intense pressure on consumers, public finances and the economy in general, led to the emergence of a debate at the European level on the subject, which culminated at the end of 2023 in an agreement on a reform of the organisation of markets in Europe⁹⁰. The aim is to bring production costs more into line with the bills paid by electricity consumers while maintaining the efficiency of the short-term market and strengthening incentives for investment in the new electricity generation facilities required for decarbonisation. The foundations of the short-term spot market remain unchanged, and the emphasis is on developing futures markets and regulations to encourage public or private guaranteed price contracts between producers and consumers⁹¹ (see the *Prices* chapter).

Finally, the strengthening of exchange capacities is part of the European Union’s political project. The European regulation “on the governance of the energy union and climate action”⁹² requires each Member State, as part of its national energy-climate plans, to prioritise its investments in interconnections in order to target capacity equal to 15% of its production capacity in 2030, subject to a positive cost-benefit analysis for each investment and certain conditions, in particular environmental integration. Under the Trans-European Networks for Energy regulation, the European Union has introduced the concept of “projects of common interest”

⁸⁹. In March 2022, this synchronous system was urgently extended to Ukraine and Moldova to support the stability of the electricity network in these regions by speeding up procedures already underway.

⁹⁰. Council of the European Union, *Press release. Reform of the organisation of the electricity market: the Council and the Parliament reach an agreement, 14 December 2023*

⁹¹. The two main instruments are (CfD, Contracts for Difference) and Power Purchase Agreements (PPA). The most difficult debates concerned the eligibility of different production sources for state-guaranteed contracts.

⁹². Regulation (EU) 2018/1999 of 11 December 2018.

which allows interconnection projects that benefit from it to become eligible, under certain additional conditions, for European financial support under the *Connecting Europe Facility*.

The operation of the power system on a European scale is now a reality, which proves essential when the French power system finds itself in a situation of supply tension, as was the case in the autumn-winter of 2022/2023. Over the past ten years, the strengthening of interconnections between countries and the development of variable renewable energies have led to a significant increase in exchanges between countries, and France is no exception.

Located at the intersection of several electric peninsulas (Iberian Peninsula, Italy, Great Britain) and with significant installed production capacities, France participates fully in European exchanges. From a technical and economic point of view, it would not be optimal to size the production fleet to systematically and fully cover periods of high consumption. This is all the more true in France, where consumption is highly sensitive to temperatures (see the Consumption section). So if there is tension in the supply-demand balance, even outside of a crisis situation, it is normal for the country to find itself in an importing position. However, as French production (nuclear, hydropower and other renewables) is more competitive than that of most of its neighbours, France becomes an exporter again as soon as the balance between supply and demand is not strained, i.e., the vast majority of the time. **The interconnection of France with other European countries thus allows it on the one hand to ensure its security of supply and on the other hand to find economic opportunities for its low-carbon production and contribute to the decarbonisation of the European mix.**

Thus, during 2022, flows were well aligned with the physical needs of the power system: while the balance of French exchanges is usually in the nature of being a net exporter, it became an importer in 2022 at a time when national production was falling as a result of the unavailability of a large number of nuclear reactors and reduced hydropower generation. The increase in market prices and the inversion of France's electricity exchanges are twin phenomena resulting from the same physical need, that of calling on more expensive production resources located in neighbouring countries, essentially in place of French nuclear reactors made unavailable by checks and repairs linked to stress corrosion cracking from December 2021. This was particularly the case in the summer of 2022, when pressure on the French power system reached its peak.

The improvement in the fundamentals of the supply-demand balance in France led to a reversal of the situation in 2023, with a marked fall in prices (see the Prices chapter) and an exchange balance that became largely export-oriented again (see below), showing the temporary nature of this massive use of foreign production. This development in exchanges, synchronised with the development of the system's physical requirements, shows that Europe now has, with the interconnected market, an extremely efficient and responsive short-term allocation system, which did not fail during the crisis period, whose rules have not been called into question by any country, and which operates in such a way as to achieve the objective of maintaining security of supply. The legitimate questions raised by this market in terms of its ability to enable a policy of mass electrification must not obscure this essential result of twenty years of technical integration of power systems on a European scale.

4.2 Net exports reached 50,1 TWh

From the point of view of exchanges, 2022 was a significant year for France: for the first time since 1980, the country imported more electricity than it exported; the balance reached 16.5 TWh in terms of imports. **In 2023, a reversal of France's net position vis-à-vis other European countries occurred: the annual balance became export-oriented again, reaching 50.1 TWh in the direction of exports.** This value, more in line with the long-term average over the previous years (about 55 TWh/year of net exports on average over the period 1990-2022), reflects the clear improvement in the availability of the production capacities of the French power system (see the *Production* chapter). In addition, **the monthly balance was export-oriented throughout the year.**

The turnaround in France's net balance between 2022 and 2023, which was very substantial (+67 TWh difference between the 2022 balance and the 2023 balance), and in the end quite rapid, testifies to the robustness of the power system in the face of the crisis it experienced in 2022. **The fact that France had to import more electricity than it exported is more cyclical than structural**, and it was closely linked to the difficulties experienced

by the French production fleet in 2022, in particular nuclear power and to a certain extent hydropower. This has demonstrated the usefulness of a high level of interconnection to strengthen the security of supply, as well as the smooth operation and flexibility of the European electricity exchange system (see above).

Although the monthly balance was export-oriented throughout the year, its magnitude changed from month to month. In the first quarter, the balance was positive but close to equilibrium, with France still importing high volumes on some borders (Spain and Core) and exporting on others (Italy, Switzerland and the United Kingdom, see the *Analysis by border*). From April, with the usual fall in consumption in France after the winter and still-high nuclear power availability (see the *Production* and *Consumption* chapters), the balance became strongly export-oriented, and imports were low in volume (about 1 TWh per month on average). In December, abundant wind power generation, higher-than-normal temperatures and increased availability of nuclear power compared with the same period in 2022 resulted in an export balance of almost 6 TWh, which is one of the highest December balances since 2005.

Figure 4.1: Physical exchanges of electricity between France and neighbouring countries between 1953 and 2023

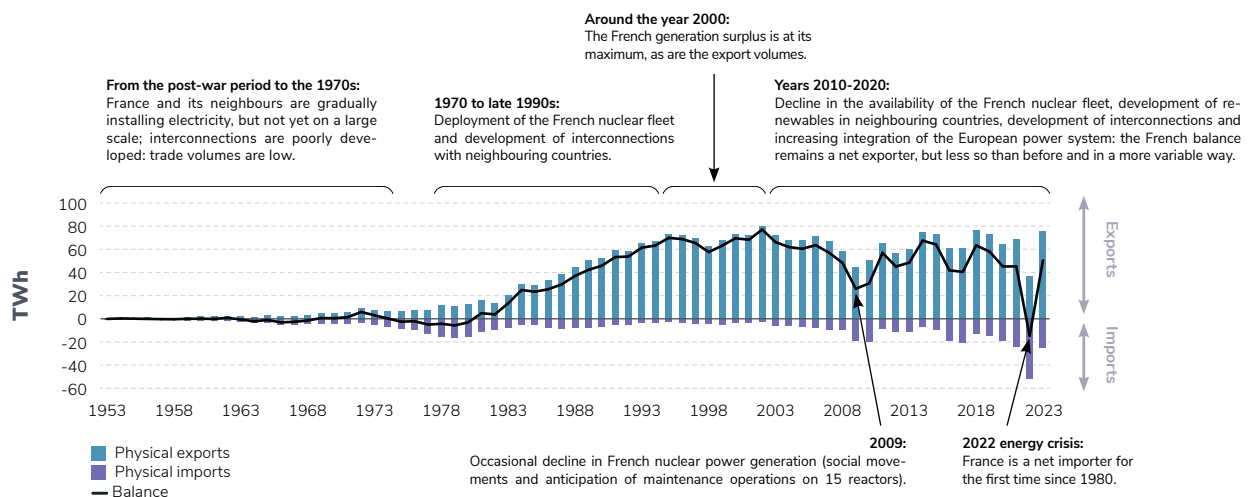
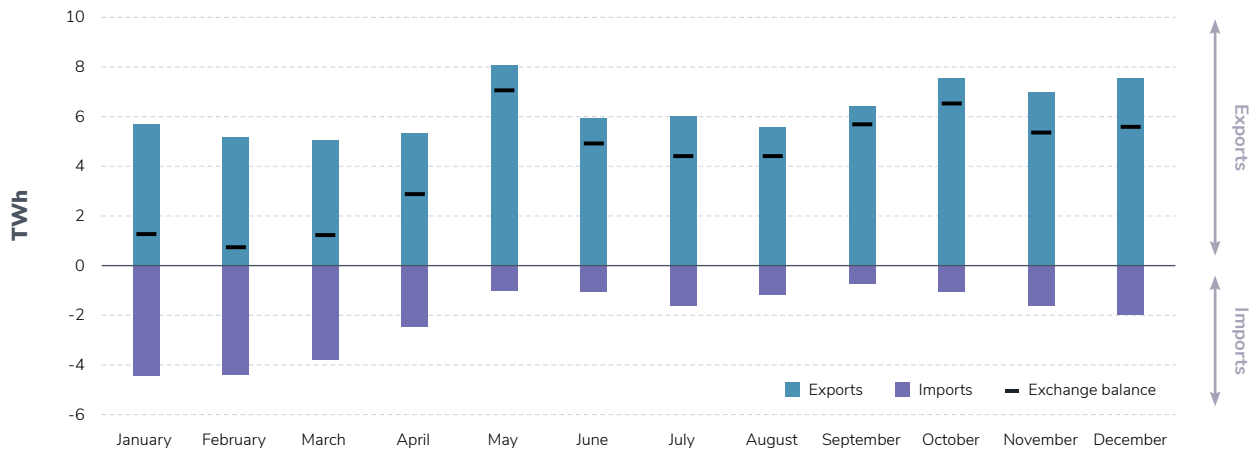


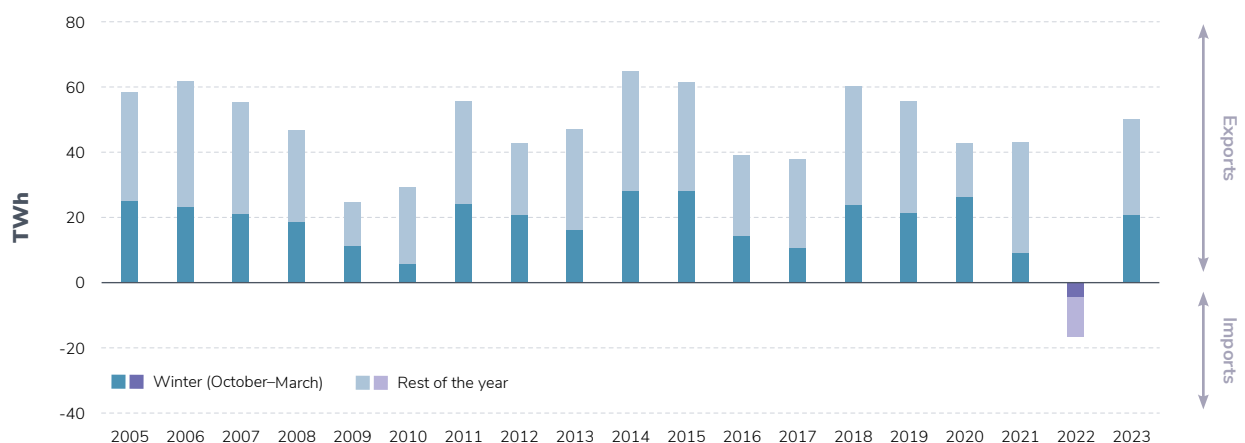
Figure 4.2: Monthly electricity exchanges between France and neighbouring countries in 2023



In 2022, the unusually large balance was mainly built up during the summer, when the availability of nuclear power reached an all-time low and low rainfall affected hydropower generation. In 2023, the distribution of the construction of the export balance between the winter season

(October-March) and the rest of the year was more balanced. In the last quarter of 2023, in particular, the balance was among the highest observed in this period since 2005 (17 TWh of net exports, or one-third of the net balance over the entire year).

Figure 4.3: Balance of electricity exchanges between France and neighbouring countries according to the season



4.3 The historical analysis of hourly exchanges, in addition to the annual and monthly breakdowns, provides a complete picture of the operation of the French and European power system

When analysing exchanges between France and other European countries, it is possible to identify major trends based on structural characteristics, as well as cyclical effects and occasional risks. These different levels of analysis are complementary.

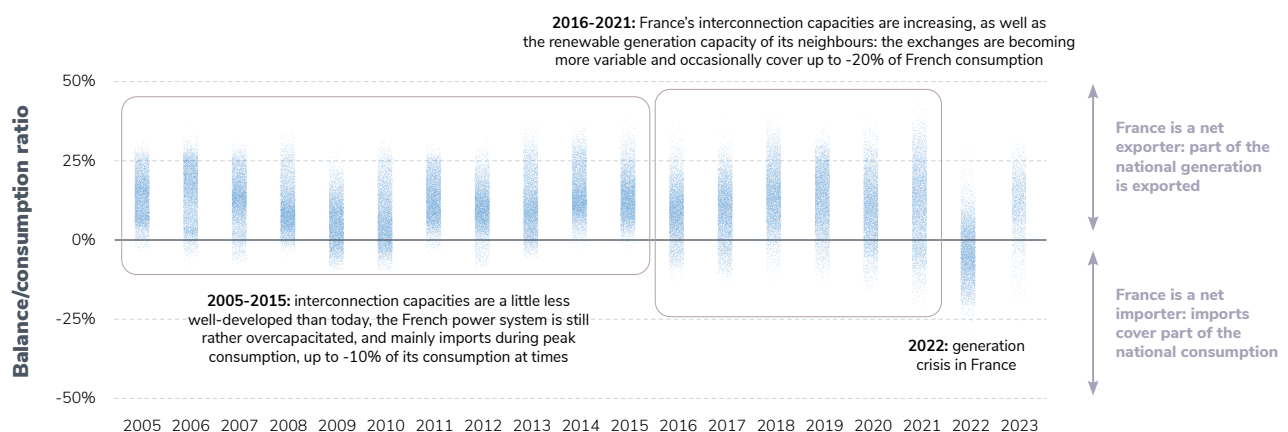
Annual volumes and their development over a long period of time give an indication of structural trends. With the development of the nuclear fleet from the 1980s, France found itself in a position to produce much more electricity over the year than was necessary for domestic consumption, and therefore to export this surplus to its neighbours. In 2002, the balance reached an absolute maximum of 77 TWh of net exports. This surplus was then slightly diminished from the first half of the 2000s, due in particular to the downward trend in the availability of nuclear power and the closure of the most heavily polluting thermal power plants in order to meet the environmental objectives of decarbonising the power system (see the *Generation and Emissions* chapters), but also to

the rise of renewable energies in neighbouring countries, particularly Germany and (more recently) Spain. The decline in the French export balance in the 2010s compared to the peaks reached in the 2000s therefore results from a slight structural decrease in the relative advantage of French electricity generation compared to its neighbours, but this is due at least as much to the transformation of the generation mix of other countries as to a loss of competitiveness of its own.

Aggregated monthly volumes show the cyclical trends that can be observed over a period of several months. At this level of detail one can see, for example, the rise in France's import balance in the summer of 2022, when nuclear availability was at its lowest, and the gradual return to a net export position as efforts to bring reactors back into service took shape.

Finally, the hourly distribution of France's positions highlights the one-off nature of certain situations, in particular the heavily importing and exporting positions, which concern only a few hours in the year. On the graph, this corresponds to the few extreme points of the annual distributions. Although relatively infrequent throughout the year, situations of heavy imports are nevertheless part of the normal functioning

Figure 4.4: Distribution of the ratio between the exchange balance and unadjusted consumption in France for the year 2023 and for several recent years (one point = one hour over the year)



Reading: using the convention common to all graphs (positive balance = France exports, negative balance = France imports), the quantity represented, for a given hour, is written: $\text{Ratio} = \frac{\text{France net balance}}{\text{Consumption}}$. Thus, a negative ratio means that France imports, and is similar to a rate of coverage of consumption by imports.

of the power system, particularly during periods of high consumption in winter, mainly because consumption in neighbouring countries does not present the same level of thermosensitivity as consumption in France.

While the rates of coverage of French consumption by imports had been unusually high for a large part of the time in 2022 due to the crisis in production in France, their distribution over the year 2023 was more similar to that of the period 2016-2021. There has also been a “broadening” of the distributions of these coverage rates over time, particularly in the second half of the 2010s. This phenomenon is linked to two structural changes in the power system:

- on the one hand, the massive development of renewable energies in France and especially in neighbouring countries, which has the effect of making exchanges more “dynamic”, i.e. more variable, as well as increasing the number of time periods when it makes economic sense to import from neighbouring countries. This is an expected and normal effect: exchanges make it possible to take advantage of the complementarities between the generation, particularly renewable, and consumption profiles of the various interconnected countries;
- furthermore, the development of interconnection capacity is essential to support the growing penetration of renewable energies in the electricity mix on a European scale.

4.4 Exchanges with neighbouring countries: analysis by border

In terms of exchanges, the borders between France and its neighbours can be divided into two categories, depending on the bilateral balance between France and each of these countries in 2023:

- the borders on which France has been a major exporter: the borders with Great Britain, Switzerland and Italy;
- borders where the balance is close to equilibrium: Spain (from which France imports to a small extent) and the Core region (Germany/Belgium, to which France exports to a small extent)⁹³.

Figure 4.5: Electricity exchanges between France and neighbouring countries in 2023

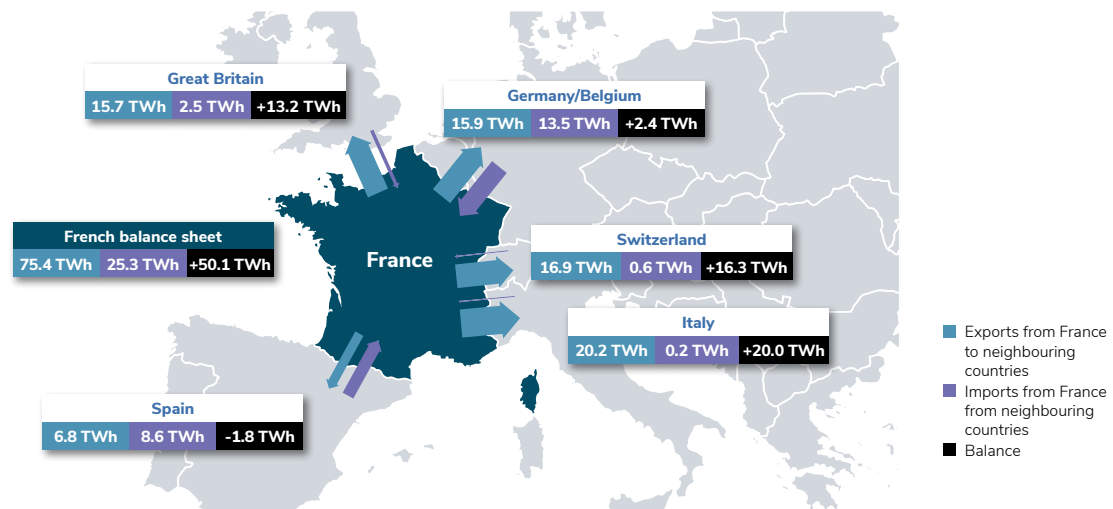
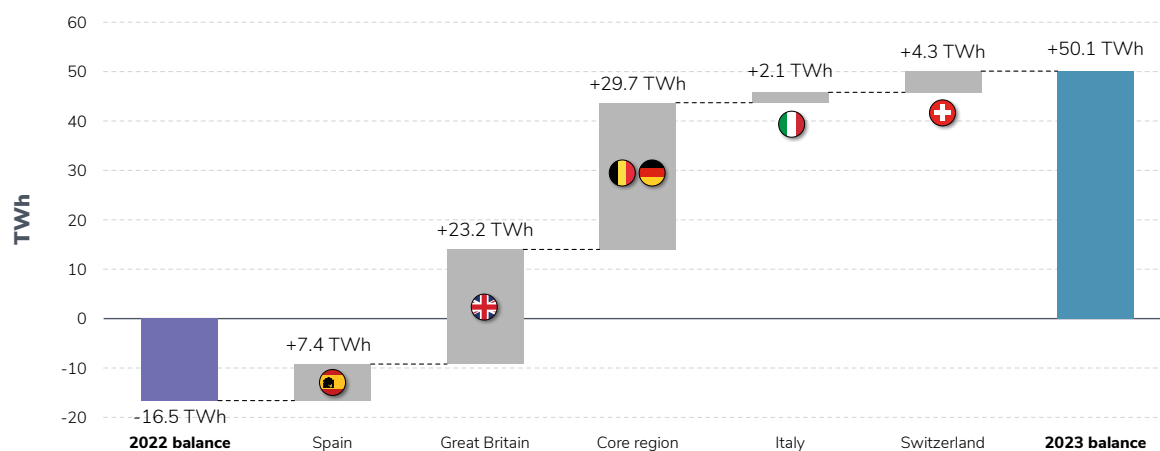


Figure 4.6: Contribution of the various borders to the development of the balance of French electricity exchanges between 2022 and 2023



⁹³ On this border, exchanges are organised at the level of a set of countries, known as the "Core region". For France, this organisation means that it is irrelevant to isolate exchanges with each of its two neighbours in the Core region, Belgium and Germany: these are referred to as exchanges with the Core region without distinction.

Exchanges on the various borders made a mixed contribution to the rebuilding of the balance in 2023, with a strong export balance (50.1 TWh), compared with the import balance (16.5 TWh) in 2022. The difference in the balance between 2022 and 2023, of 66.6 TWh, is 80% due to exchanges on two borders: with Great Britain (+23 TWh compared with 2022) and with the Core region (+30 TWh compared to 2022). On the Spanish border, the mixed situation during 2023 (see Spain below) led to a smaller difference of +7.4 TWh between the 2022 balance and that of 2023. On the other hand, the balance on the borders with Italy and Switzerland did not vary significantly in 2023 – having remained largely export-oriented as in 2022: these borders therefore contributed less to the reversal of the balance between 2022 and 2023.

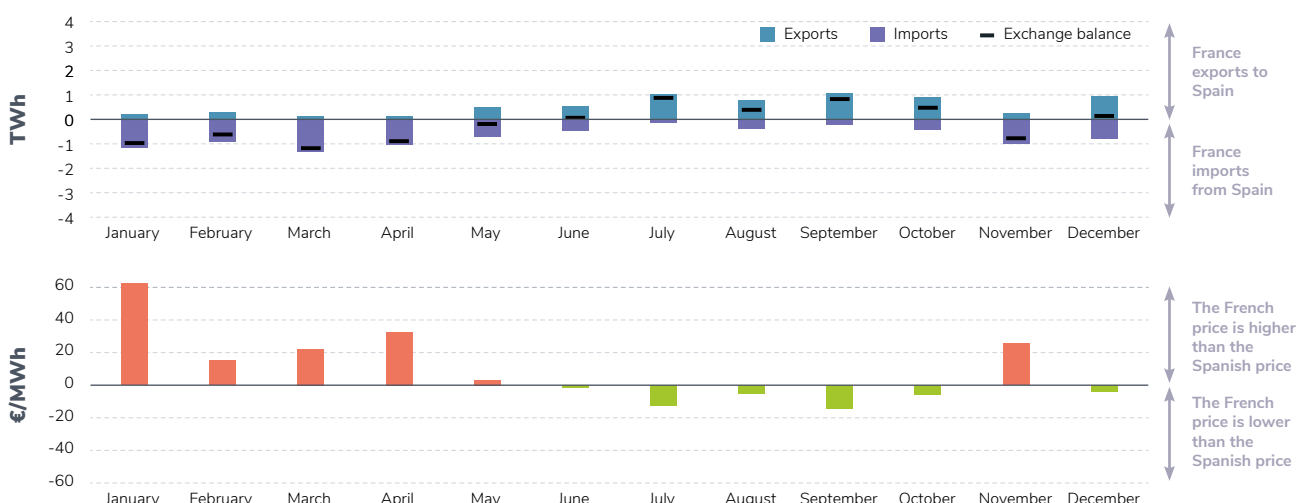
4.4.1 Spain

French and Spanish electricity consumption is countercyclical on an annual scale. For example, France usually exports large volumes to Spain in the summer, when consumption is at its highest in Spain, mainly due to the use of air conditioning. In winter, the situation tends to be slightly more balanced: France regularly imports from Spain during peaks in French consumption, but overall remains a net exporter in terms of volume.

In 2022, however, most of the exchanges were from Spain to France, as a result of two major factors: the production crisis in France, and the introduction by Spain, in June 2022, of the mechanism for capping the price of gas used to generate electricity^{94,95}, sometimes referred to as the “Iberian mechanism”.

In 2023, three major phases were observed with regard to exchanges at the Spanish border. **From January to May**, France remained a major

Figure 4.7: Monthly volumes of electricity exchanges between France and Spain (top) and monthly average differences between French and Spanish spot prices (bottom) in 2023



⁹⁴ RTE, *Electricity Report 2022, Exchange chapters*

⁹⁵ This mechanism, applied from mid-June 2022 in Spain and Portugal, consists of a ceiling on the price of natural gas used for electricity generation. The difference with the real price of gas is covered by a public subsidy, i.e., by the government budget. As the marginal electricity generation resources in Spain are most often gas-fired power plants, this had the concrete effect of also limiting electricity prices at the time when gas prices were highest.

importer from Spain, in line with the second half of 2022. From the summer onwards, however, the situation was reversed: the fall in consumption in France, the rise in consumption in Spain and the continued high availability of French nuclear power meant that the exchange balance on this border became a net exporter to Spain from June onwards. Finally, as winter approached, the increase in consumption in France combined with very high wind power generation in Spain (an average of almost 14 GW over the month of November 2023) once again led to a reversal in exchanges: France was a net importer from Spain in November. In December, the balance was close to equilibrium. Similarly, looking at the total for the year, the balance of exchanges with Spain was close to equilibrium, reaching 1.8 TWh in the import direction.

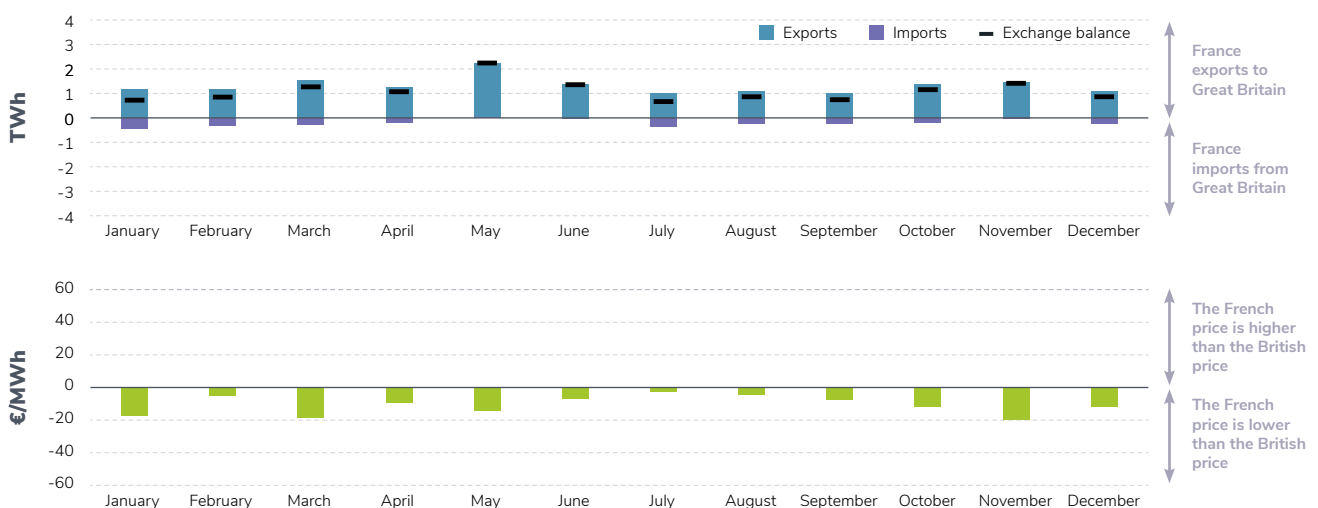
It should be noted that the Iberian mechanism has not been in effect since February 2023, as gas prices have fallen below the cap set by the authorities (see the Prices chapter). This cap therefore played no role in determining exchanges between France and Spain in 2023.

4.4.2 Great Britain

Since the commissioning, in 1986, of the very first electrical connection between Great Britain⁹⁶ and the continental European power system⁹⁷, France has been exporting large volumes of electricity to Great Britain for most of the year. In winter, when consumption is high in France, however, it is common for exchanges to be reversed and for France to import from Great Britain.

In 2023, in accordance with historical practice, most of France's exchanges with the United

Figure 4.8: Monthly volumes of electricity exchanges between France and Great Britain (top) and monthly average differences between French and British spot prices (bottom) in 2023



⁹⁶ This refers to exchanges with Great Britain, and not with the United Kingdom, because the power systems of the island of Great Britain and Northern Ireland are not synchronous, are not managed by the same transmission system operator (National Grid for Great Britain and SONI for Northern Ireland), and do not belong to the same market area. The Northern Irish electricity system is integrated with that of the Republic of Ireland; the two Irish transmission system operators (EirGrid for the Republic of Ireland) have jointly operated a single market area for the entire island of Ireland, the Single Electricity Market, since 2007. The Irish network is interconnected with the British network by two DC links with a capacity of 500 MW each: the East-West Interconnector, between the Republic of Ireland and Wales, and the Moyle Interconnector, between Northern Ireland and Scotland. A third HVDC link is planned, between the Republic of Ireland and France, this time: this is the Celtic Interconnector, with a capacity of 700 MW and whose commissioning is scheduled for 2027.

⁹⁷ This was the IFA2000 DC interconnection, with a bi-directional capacity of 2 GW. Since then, two other interconnections with France have been commissioned (IFA2 in 2020, then Eleclink in 2022), bringing the maximum exchange capacity to 4 GW.

Kingdom were export-oriented. Over the last ten years, the margins of the British power system have shrunk, due in particular to the closure of a large number of coal-fired power plants as part of the energy transition⁹⁸; between 2012 and 2023, coal-fired production fell from 23 GW to 2 GW (see the Europe chapter). This state of affairs, combined with its island nature and the fact that France is by far the country with which it is most interconnected, have led France to be a fairly significant exporter throughout 2023 on the Franco-British border. The annual balance vis-à-vis Great Britain amounted to 13 TWh in exports.

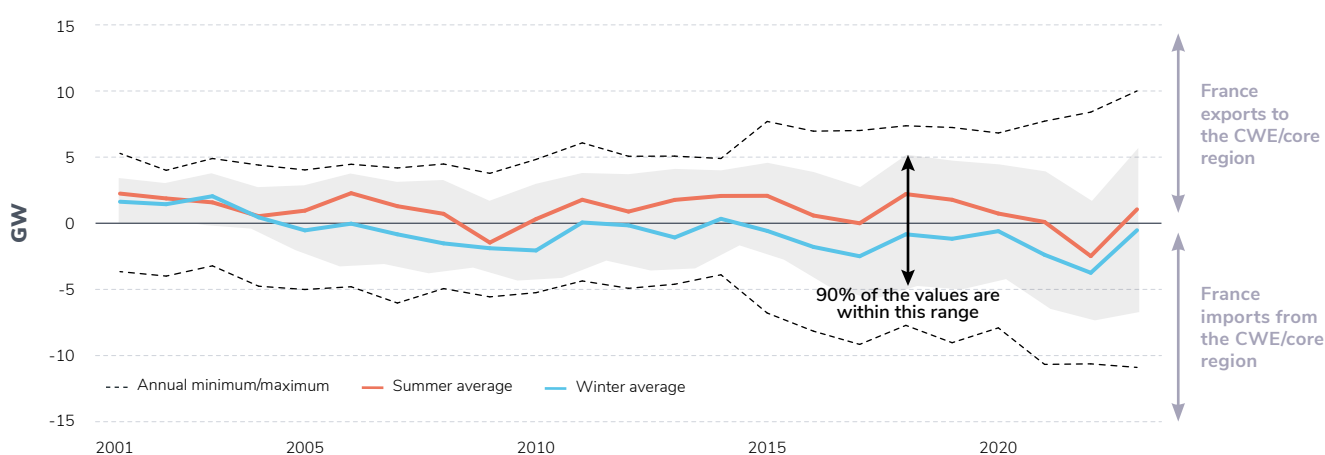
As part of its energy transition, the United Kingdom has been pursuing a massive interconnection strategy with the continent since the 2000s, with the aim of strengthening its security of supply and facilitating the integration of onshore and offshore wind power generation, which is developing very rapidly (see the Europe chapter). Interconnections have been put into service with the Netherlands (2011), Belgium (2019), Norway (2021) and, most recently, Denmark (2023), bringing the physical

exchange capacity between Great Britain and the continent to nearly 9 GW, against only 2 GW in 2010.

4.4.3 Core region (Germany and Belgium)

Exchanges between France and the Core region are characterised by greater volatility than on other borders. Depending on the supply-demand balance situation and the production costs on either side of the border, they are likely to change direction quickly and to a very large extent; for example, the maximum variation in exchanges observed over a period of 3 hours is 12.5 GW⁹⁹. This trend has been accentuated since 2015 as part of the integration and increasing fluidity of exchanges in the Central Western Europe zone first, then in the Core region from June 2022. On an annual basis, since 2001, France has oscillated between a position of being a net importer and a net exporter vis-à-vis Germany and Belgium. It is usually in summer, when available production in France far exceeds consumption, that exports to this region are highest. In winter, on the other hand, France is more of an importer.

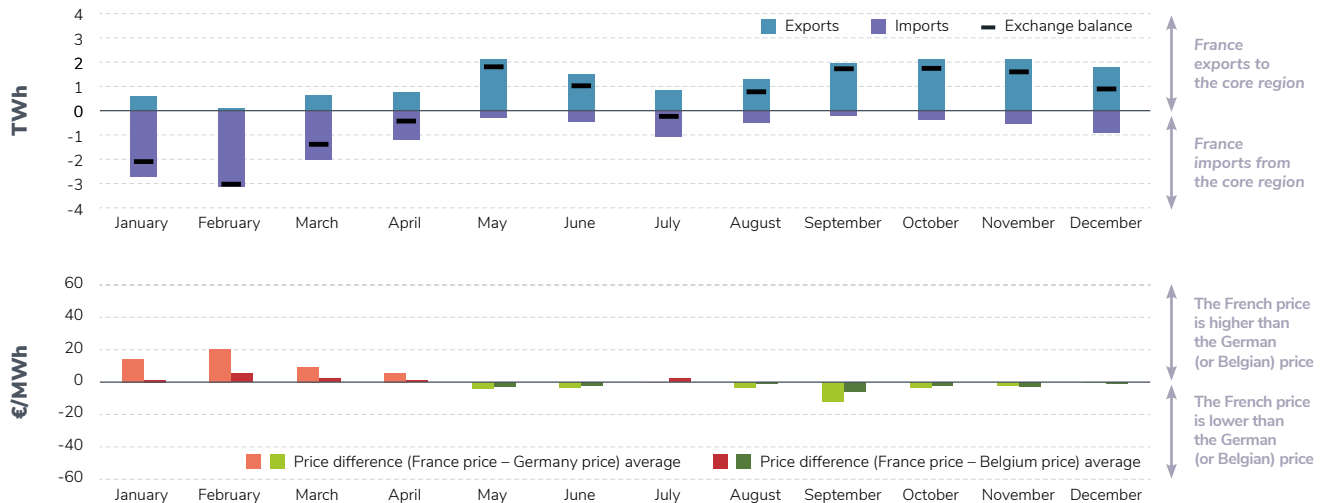
Figure 4.9: Annual distribution of electricity exchanges between France and Germany and Belgium over the period 2001-2023



⁹⁸. The United Kingdom is one of the countries in Europe with the fastest decline in greenhouse gas emissions related to the power system in recent years (see the Emissions and Europe chapters).

⁹⁹. By way of comparison, the maximum variation in the balance over 3 hours observed on the other borders is 7 GW on the British border, and less than 6 GW on the others. The average variation of the balance over a period of 3 hours at the border with the Core zone is 1.6 GW, while it is less than 800 MW on the others.

Figure 4.10: Monthly volumes of electricity exchanges between France and the member countries of the Core region (top) and monthly average differences between French spot prices and the spot prices of these countries (bottom) in 2023.



The first months of 2023 were consistent with the history of recent winters: France was a major importer from Germany and Belgium. In the spring, exchanges on this border gradually became balanced, with France becoming a net exporter again in May 2023. Over the summer, exchanges were generally export-oriented, except in July, when they were close to equilibrium. Over the rest of the year, France maintained a fairly strong export position, including in December, thanks to good nuclear power availability, very high wind power generation and unseasonably high temperatures that kept consumption at moderate levels.

4.4.4 Italy

In 2022, the Italian border was the only one on which the balance, which is usually very export-oriented, was not excessively affected by the production crisis in France. For a long time now, the Italian power system has had insufficient capacity to meet its needs, particularly in the summer when consumption is at its highest,

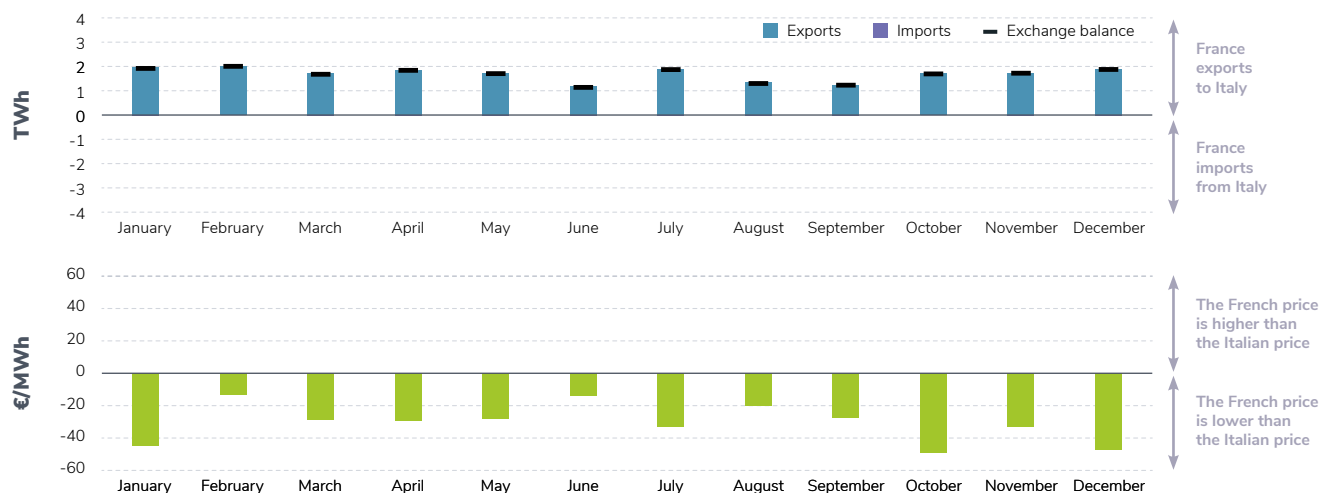
and it relies on imports to complete its mix. Furthermore, despite strong growth in renewable production capacity, Italy's production fleet is still largely made up of gas-fired power plants. Since the late 1980s, imports have accounted for between 10 and 15% of Italy's annual electricity consumption¹⁰⁰. **In 2023, exchanges between France and Italy remained in line with the historical trend: they were almost entirely export-oriented, with a price differential favourable to France.**

This structural situation does not prevent France from occasionally importing from Italy over certain strained time periods. In this regard, the analysis of exchanges between France and Italy highlights the fact that annual and monthly total balances hide a variety of different one-off situations.

Finally, on this border: the new **Savoie-Piémont** direct current interconnection will be fully operational from August (see *Interconnections* below).

100. Terna, Dati Storici 2022

Figure 4.11: Monthly volumes of electricity exchanges between France and Italy (top) and monthly average differences between French and Italian spot prices (bottom) in 2023

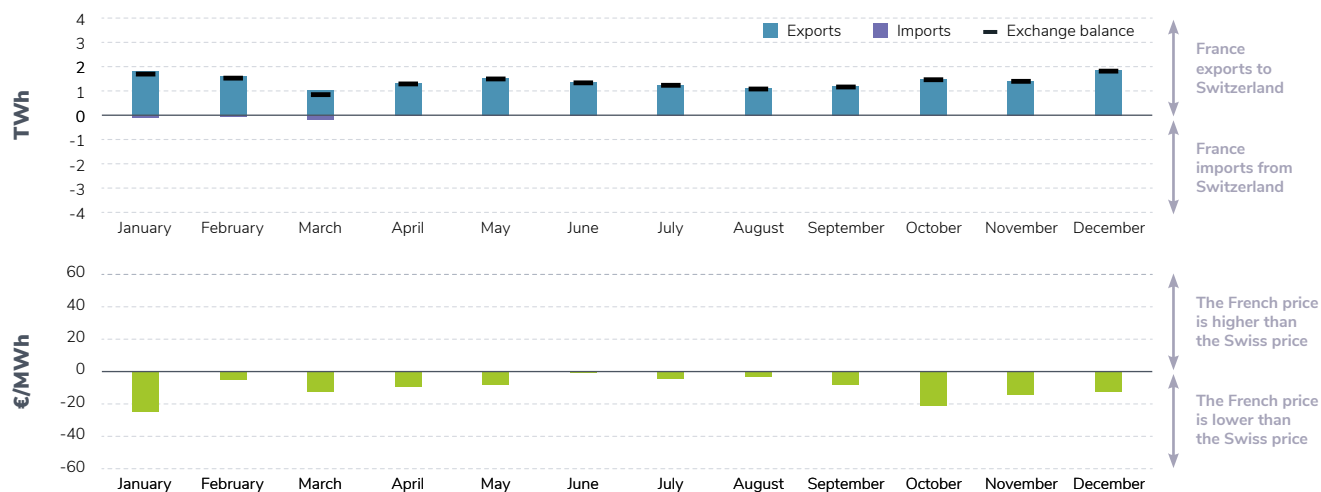


4.4.5 Switzerland

In 2023, **on the Swiss border, exchanges were mainly export-oriented in volume**, following the historical trend. Spot prices were on average lower in France, most of the time.

The country analyses above only concern exchanges between France and its direct neighbours. In reality, the European network is interconnected, and a country can, at any given moment, be importing at one border and exporting at another. It is

Figure 4.12: Monthly volumes of electricity exchanges between France and Switzerland (top) and monthly average differences between French and Swiss spot prices (bottom) in 2023



101. This is indeed a hypothesis, which does not, however, reflect the strictly physical reality of electricity exchanges, which are impossible to follow in detail. This approach, taking into account an expanded scope, is detailed in the section Analysis of exchanges with an expanded scope.

then possible to consider that, in a very simplified manner, part of the imports “cross” the country in question and are simultaneously “re-exported”¹⁰¹ to the third country. This is particularly the case with Switzerland. In fact, Switzerland’s production capacity is generally sufficient to cover its consumption, and because of its geographical position, Switzerland frequently imports electricity from one or more of its borders, notably France, and exports it to other countries at the same time, in particular Italy. On this point, see the section Analysis of exchanges with an expanded scope.

4.4.6 Synchronisation between exchanges at different French borders

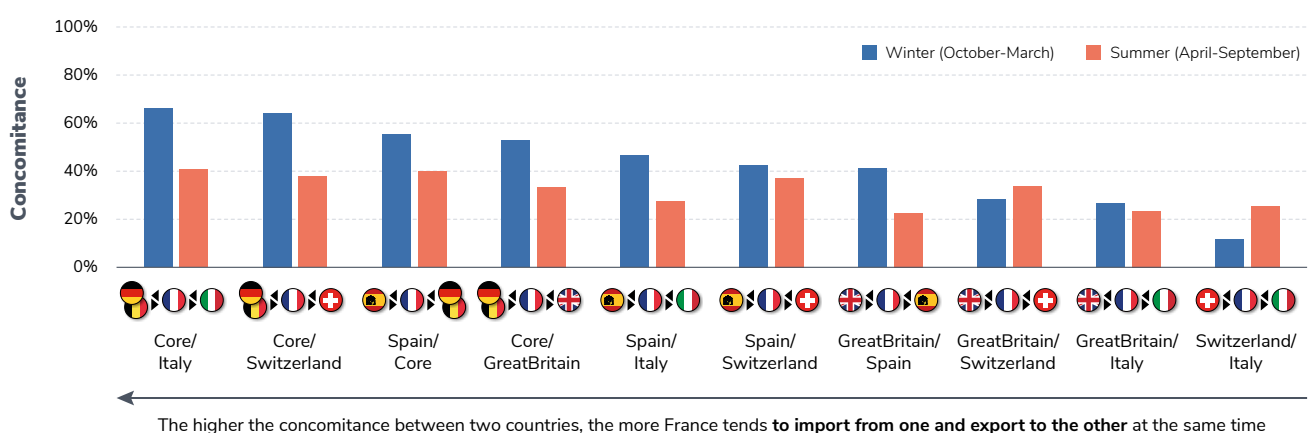
It is interesting to cross-analyse exchanges on the various borders to see the extent to which it tends to be “synchronised”; in particular, “anti-synchronisation”, i.e., the fact that two countries have flows towards France in opposite directions, suggests that part of these flows “crosses” the French network to go from one neighbouring country to another. This situation indicates a certain complementarity between the generation mix of our neighbours. For

a given pair of countries, measuring the proportion of time over which exchanges between France and each of these countries are established in opposite directions makes it possible to provide information on the degree of synchronisation¹⁰².

The first observation is that the proportion of time when exchanges are synchronised was higher in winter than in summer for virtually all the pairs from neighbouring countries. In winter, more than 60% of the time, exchanges between France and the Core region on the one hand, and France and Italy and Switzerland on the other, were established in opposite directions (that is to say, it is possible to consider that electricity was circulating between these two countries).

North-south flow patterns, particularly between Germany and Spain, are emblematic of the complementary nature of a mix dominated by wind power on the one hand, and a mix with a high proportion of solar power on the other¹⁰³. In 2023, such patterns were established around half the time, more markedly in winter than in summer.

Figure 4.13: Synchronisation between electricity exchanges at different French borders over the year 2023



Reading: for the year 2023, between January and March, and between October and December, 60% of the time, France imported from the core region and exported simultaneously to Italy, or exported to the core region and imported simultaneously from Italy

¹⁰². This measure does not provide any information on the volumes concerned by these through-flow systems, nor on their direction, and therefore offers only a partial view of the complementarity between the mixes.

¹⁰³. RTE, 2023-2035 Generation Adequacy Report – Chapter 5: Europe

4.5 Analysis of French exchanges at the wider European level

As the European network is interconnected, it is possible to intuitively assume that France's exchanges with its direct neighbours, as presented in the analysis by border, has components originating in or destined for more "distant" countries. Schematically, if, over a given period of time, France imports electricity from Spain but Spain imports it from Portugal at the same time, then it may be legitimate to consider that, over the period in question, part of the electricity exchanged between France and Spain is attributable to production in Portugal. Similarly, if France exports electricity to Italy but imports it at the same time from Germany, it may be legitimate to consider part of these exports as coming from Germany and not from French production. The results of the analysis of exchanges with this approach, taking into account a European scope extended to 15 countries¹⁰⁴, are presented here. These are not measured data but the results of modelling¹⁰⁵, which can however provide additional information

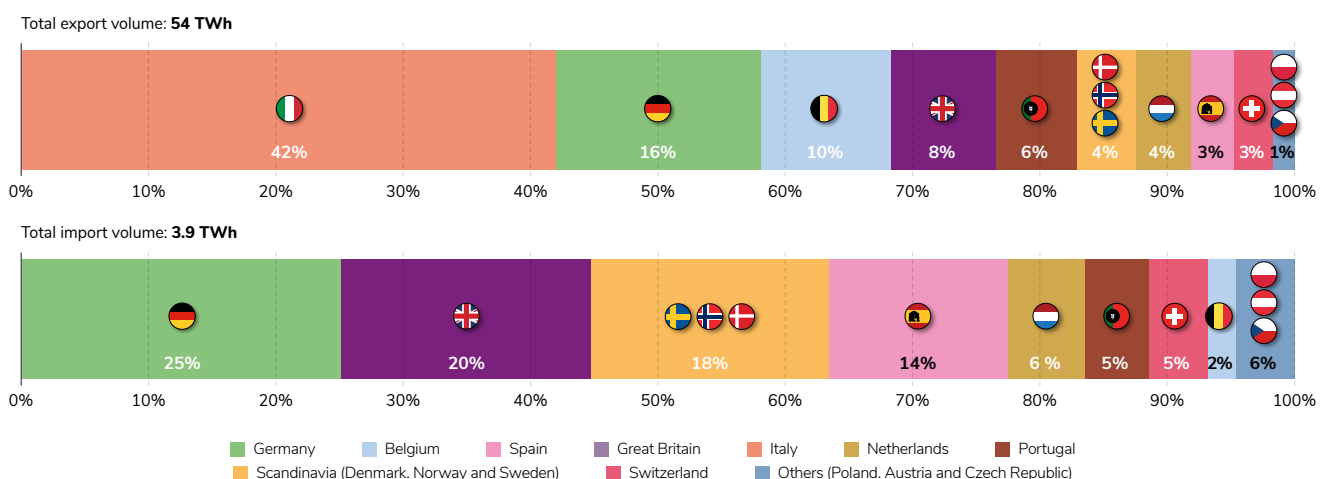
useful for understanding the operation of the European power system.

4.5.1 Overview and recent history

When we look at exchanges in a wider area, we see that, although the volumes exchanged with direct neighbours remain predominant, it is possible to trace significant flows from or to more distant countries, in particular the Nordic countries (Sweden, Norway and, to a lesser extent, Denmark), the Netherlands and Portugal (see figures 14 to 18).

In the expanded scope, French exports appear to be overwhelmingly destined for Italy (almost a third of export volumes in 2023), whereas in the border-by-border approach they were of around the same order of magnitude to Italy and Switzerland. This confirms the intuition that a significant part of French exports to Switzerland is re-exported to Italy (see *Focus: Switzerland, transit country for electricity*). Portugal also appears ahead of Spain, which suggests that Spain, like Switzerland, is at least partly a transit country, naturally due to its geographical position.

Figure 4.14: French electricity exports (top) and imports (bottom) in the expanded scope in 2023



¹⁰⁴. The 15 countries are: Spain, Portugal, Italy, Switzerland, Austria, Germany, Czech Republic, Poland, Belgium, Netherlands, Sweden, Norway, Denmark and Great Britain. Ireland was excluded due to the insufficient quality of the data available. A wider group of countries, extending as far as Greece and Finland, was also studied: the inclusion of countries further away than the 15 selected, and whose power systems are relatively small compared with France's, does not substantially alter the results presented here.

¹⁰⁵. The foundations of the approach used in this part are set out in detail in [Bialek, J. Tracing the flow of electricity, 1996](#).

Figure 4.15: Cartography of French electricity exports and imports in the expanded scope in 2023

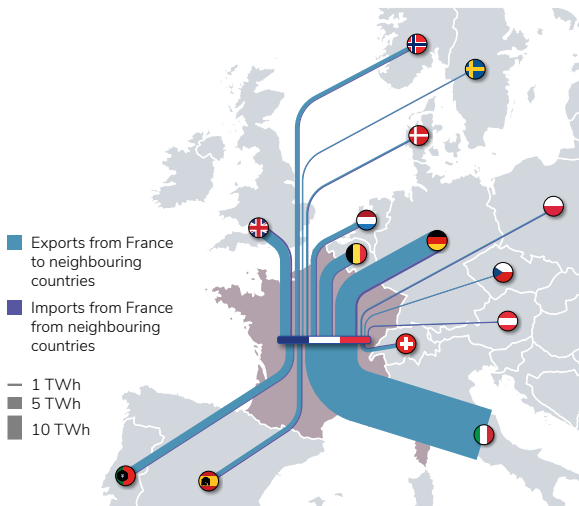
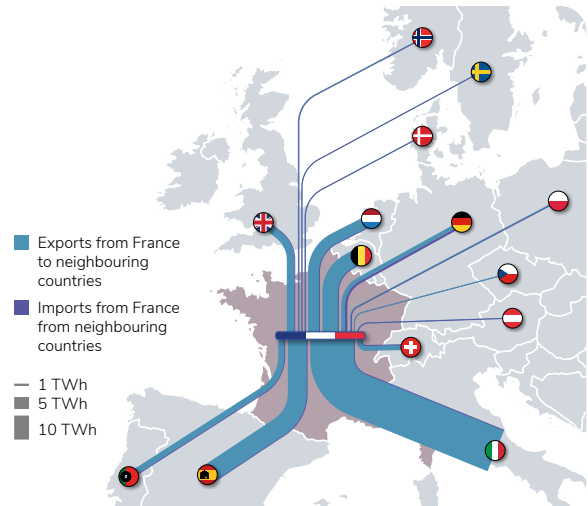


Figure 4.16: Cartography of French electricity exports and imports in the expanded scope in annual average over the period 2017-2019

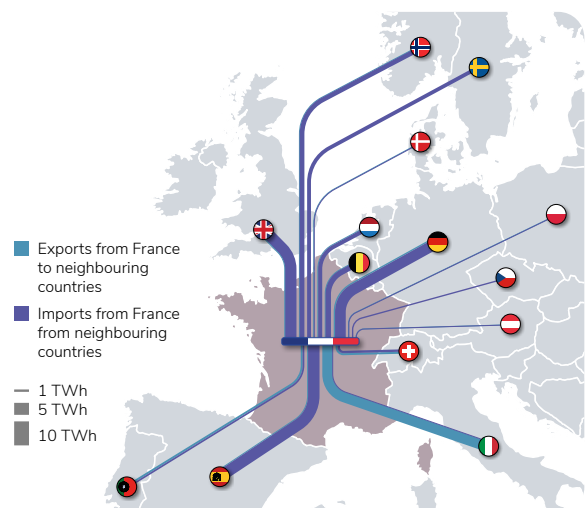


Exchanges in the expanded scope, over the year 2023, were relatively in line with the average annual exchanges observed pre-crisis, over the period 2017-2019¹⁰⁶. However, there are some notable differences between the two periods, for example:

- the decrease in volumes exported to Spain;
- the increase in volumes exported to Germany.

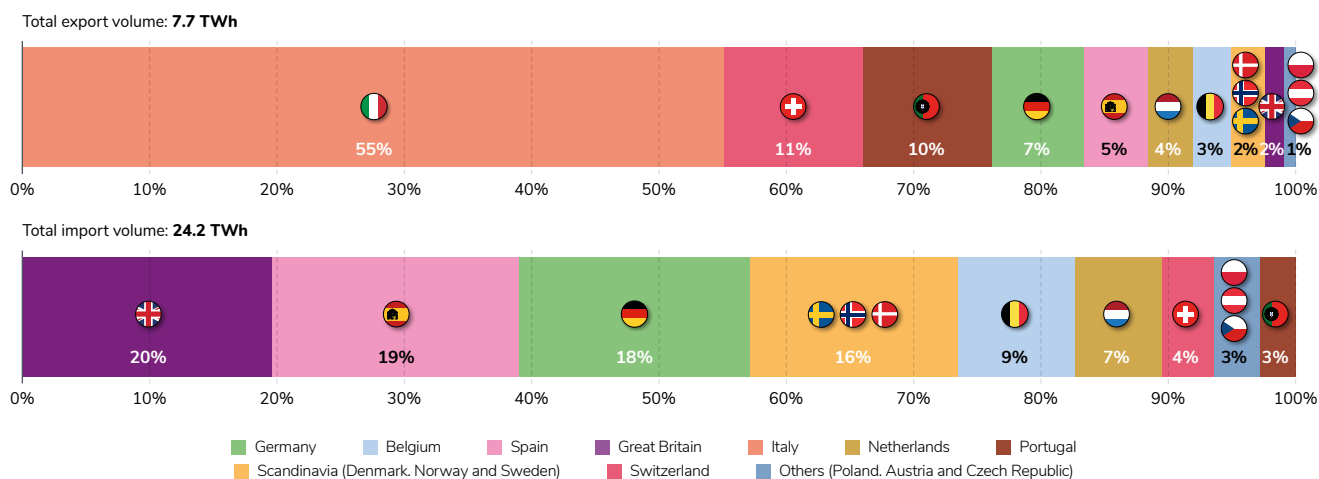
Finally, the exceptional situation in 2022 can be clearly seen, when most countries contributed to the volumes imported by France, in particular Germany, Belgium, the Netherlands, Spain, the United Kingdom and, not insignificantly, Sweden and Norway. As a result of the wider scope of the analysis, there are contributions, albeit marginal, from other countries further afield, such as Poland, Austria and the Czech Republic.

Figure 4.17: Cartography of French electricity exports and imports in the expanded scope in 2022



¹⁰⁶. Analysis with an expanded scope requires a large amount and variety of data for each country. The depth of the history is thus limited by the quality of the data available.

Figure 4.18: French electricity exports (top) and imports (bottom) in the expanded scope in 2022

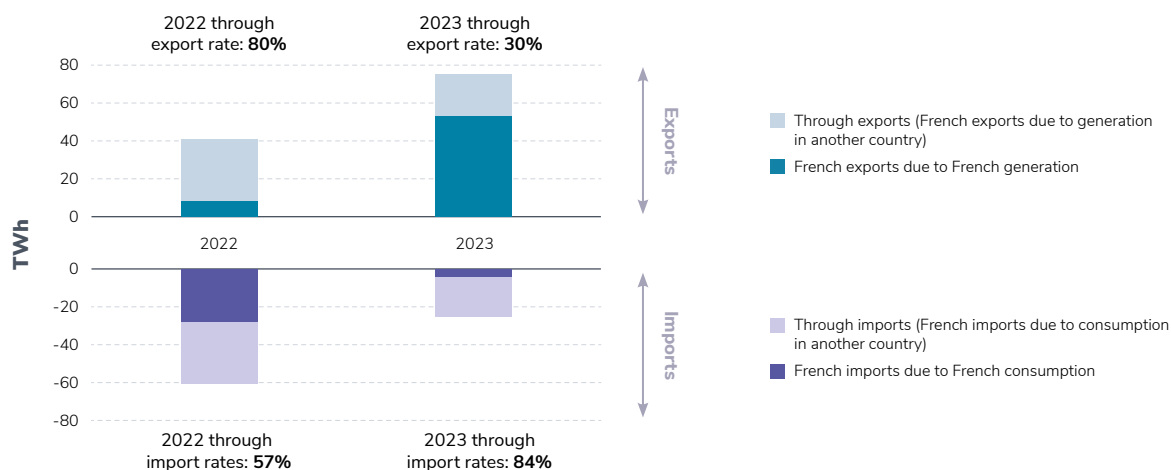


4.5.2 Depending on France's net position, exchanges "pass through" the French power system to a greater or lesser extent

Like Switzerland and Spain, France is, due to its geographical position and the differences between the electricity mixes of its neighbours, in a position to be able to import from and export to different borders simultaneously. The analysis of an expanded scope makes it possible to attribute

part of France's exports to French production, and another part to simultaneous imports on other borders, which are more likely to be attributable to production abroad. According to this simplified approach, it is possible to identify volumes of exchanges that can be said to have "passed through" the French network, as well as the proportion of imports and exports that pass through the country.

Figure 4.19: Share of French exchanges due to production and consumption in France and abroad in 2022 and 2023



An analysis of the breakdown between exchanges due to production or consumption in France, and exchanges resulting from geographical position (flows which “pass through” the country) in 2022 and 2023 allows us to draw several conclusions:

- in 2023, nearly 80% of the volumes imported by France were simultaneously re-exported;
- on the other hand, on average only a quarter of the volumes exported by France in 2023 are attributable to production in other countries; three-quarters of the volumes exported are therefore linked to French production;
- in 2022, the situation was very clearly reversed. Nearly 80% of French export volumes could be

attributed to production abroad, and therefore qualified as “cross-border”. On the other hand, only 57% of the volumes imported were re-exported: nearly half were used to supply French consumption;

- the situation varies greatly from one month to another: in fact, the rate of “cross-border” exchanges is closely linked to the proportion of time the country is a net importer, which varies significantly from month to month. In this type of analysis, we consider that a country that is a net importer over a given period of time does not contribute to exports at all: in these situations, it is totally “passed through” via outflows.



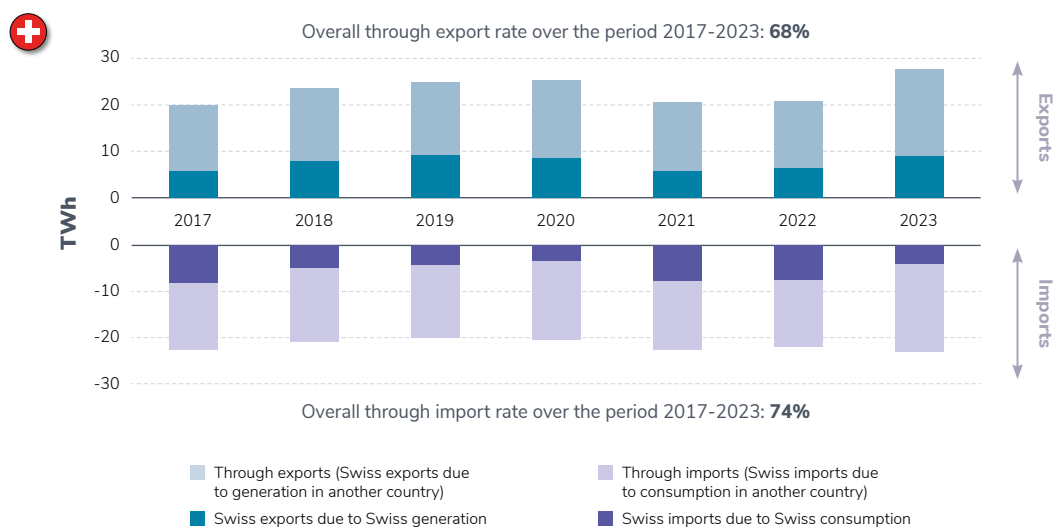
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Focus: Switzerland, a transit country for electricity

Analysis of exchanges on a broader scale and of the proportion of exchanges that passes through Switzerland illustrates the point made above: Switzerland is largely a transit country, with between 60% and 90% of its

exchanges attributable to foreign production and consumption. In this case, the production in question is largely French, and consumption is largely Italian.

Figure 4.20: Share of Swiss exchanges due to production and consumption in Switzerland and abroad (2017-2023)



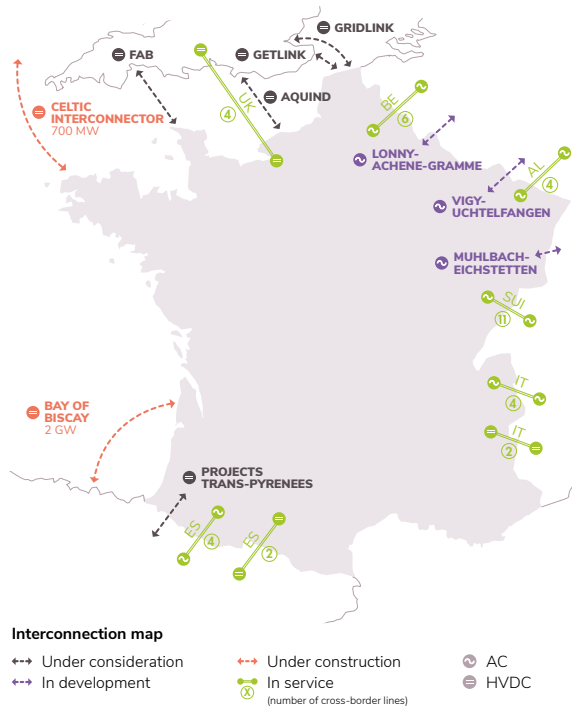
4.6 Electricity interconnections, an essential infrastructure for the energy transition

The development of electrical interconnections is one of the pillars of the European Union's energy policy. By making it possible to take advantage of the complementarities between the various countries' mixes, they make an essential contribution to the integration of renewable energies, and are a key element of the energy transition.

In France, prospective work on the power system is converging on the technical and economic interest of the massive development of interconnections, across all borders. Energy planning documents, such as the Multiannual Energy Plan (PPE), include a number of projects that contribute to increasing the capacity for exchange with other European countries. The development of interconnections is driven by the need for security of supply, but also by a form of economic rationality: the assessment of projects, which is coordinated between the network operators concerned, is based on cost-benefit analyses for the community. For France, the benefits generated by the development of interconnections are of two kinds: – making the most of surplus production, which greater interconnection capacity enables to be exported in greater quantities, and the possibility of importing electricity from neighbouring countries when it makes economic sense to do so, in particular when consumption in France is high, and it would be more costly to call on thermal production resources in France or during periods of very high renewable production in neighbouring countries. The Ten-Year Network Development Plan (SDDR) published in 2019 by RTE plans to reach an interconnection capacity of around thirty gigawatts by 2035. A new edition of the SDDR will be published in 2024 and will specify new long-term trajectories.

Interconnections are the essential infrastructures that allow the exchanges described in the first part of this chapter. For example, they made an important contribution to securing the supply-demand balance during the winter of 2022-2023. Over the next few years, several new interconnections – currently underway – should come into service and

Figure 4.21: Map of interconnections in service, under development and under consideration at the French borders in 2023



strengthen France's exchange capacity with its neighbours.

Among these, the new IFA2 and Eleclink interconnections have recently been commissioned in 2021 and 2022 at the Franco-British border, as well as the Savoie-Piémont link completed in 2023 at the border with Italy. The reinforcement of the Avelin/Mastaing-Avelgem-Horta axis, effectively commissioned in 2022, has made it possible to increase exchange capacities with Belgium, in addition to the installation of phase-shifting transformers on the Belgian side at the Aubange substation in 2021.

Exchange capacities are directly dependent on the physical capacity of cross-border lines, but also depend on the capacity of the network upstream and downstream of the border. In some cases, strengthening the exchange capacity between two countries means strengthening the lines within those countries, on either side of the border. These

Figure 4.22: Interconnections between France and neighbouring countries at the end of 2023

Neighbouring countries	In service	Under construction	In development	Under consideration
Germany	4		2	
Belgium	6		1	
Spain	6	1		1
Great Britain	4			4
Ireland		1		
Italy	6			
Switzerland	11			
Total	37	2	3	5

are not interconnection projects in the strict sense, but the objective is the same: to increase exchange capacity.

With a total of 37 interconnection lines in service, the French electricity transmission network is now interconnected with that of its six neighbours. As of 31 December 2023, two new interconnections are under construction: a DC interconnection with

Spain, and another with Ireland, which will therefore become the seventh country to interconnect directly with France. Three projects to strengthen existing lines are under consideration; they all concern the border between France and the Core region (Germany and Belgium). On a more distant and uncertain horizon, other projects with Spain and Great Britain are also under consideration.



Interconnection projects recently commissioned or currently under development or under construction

France-Italy: the Savoie-Piémont project

The Savoie-Piémont DC interconnection, which connects the French network to the Italian network, was commissioned at the end of 2023. As Italy is generally the first destination for French electricity exports (especially if one also consider exports “transiting through Switzerland”, see the *Analysis by border* and *Analysis of French exchanges at the wider European level* sections), the increase in exchange capacities at the Franco-Italian border is likely to have an upward effect on France’s exchange balance in the years to come.

France-Spain: the Bay of Biscay project

The Gulf of Biscay project consists of building a new electrical interconnection between France and Spain.

This link, which is scheduled to be commissioned in 2028, will bring the electricity exchange capacities between these 2 countries to nearly 5 GW. It will connect the Cubnezais substation (near Bordeaux) to the Gatika substation (near Bilbao). This will be the first interconnection between France and Spain to be largely submarine; the terrestrial sections will also be mostly underground. Work began in 2023.

France-Ireland: the Celtic Interconnector project

The Celtic Interconnector project consists of building a DC electricity link about 575 km long (including approx. 500 km at sea), allowing the direct exchange of electricity between France and Ireland, which are not currently interconnected (the Irish power system is only interconnected with Great Britain, see the note in the *Europe* section). With a capacity of 700 MW, this project will connect the north coast of Brittany to the south coast of Ireland. Work began in 2023; commissioning is scheduled for 2027.

France-Belgium

Between France and Belgium, the main project currently under development is the reinforcement of the existing line between the Lonny substation, near Charleville-Mézières, on the French side, and the Achène substation, in the province of Namur, on the Belgian side, as well as the internal portion of the Belgian network that is downstream, between Achène and the Gramme substation (near Liège). The strengthening of this essential axis for France-Germany-Belgium exchanges will make it possible to increase exchange capacities at the border between France and the Core zone.

The French and Belgian transmission system operators are coordinating this project with the aim of carrying out reinforcement work in the area planned between 2030 and 2032.

France-Germany

The strengthening of interconnections between France and Germany has been the subject of many studies – particularly within the framework of the European ten-year plans (TYNDP) – driven by the significant changes in the energy mix of European countries (in particular Germany, Austria, Belgium, France and the Netherlands) in the context of the energy transition. The development of new exchange capacities between France and Germany in this context will make it possible to take advantage of the complementarities between the various countries’ mixes, by facilitating the use of electricity generation capacities at the lowest cost at a given time. Currently, two projects are in development phase:

- the doubling of the axis between Muhlbach (in Alsace) and Eichstetten, near Freiburg in Germany, which is scheduled to be commissioned in 2028;
- the modernisation of the interconnection between Vigy (near Metz) and Ensdorf, near Saarbrücken, Germany, is planned for 2029.

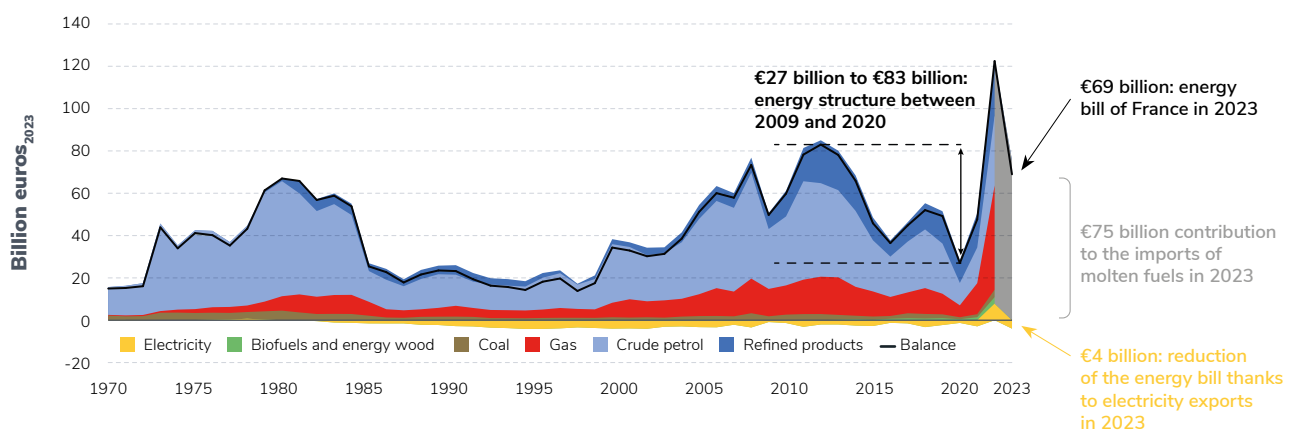
4.7 The energy bill of France is disproportionately affected by fossil fuel imports

The energy bill of France is the balance between the valuation of imports and that of energy exports, all energies combined (electricity and fossil fuels in particular). The reversal of the electricity exchange balance in 2023, and therefore the return to being a net exporter of electricity for France, has contributed to reducing the net energy bill over the year by around €4 billion²⁰²³, while the export balances during the period 2014-2019 contributed to a reduction of approximately €2 billion²⁰²³ on average. As a reminder,

France's net import balance in 2022 contributed to raising the energy bill by about €8 billion in 2023. **However, whether positive or negative, the weight of electricity in France's energy bill remains very low compared to that of fossil fuels:** in 2022, fossil fuel imports had cost €115 billion²⁰²³; in 2023, this amount should be around €80 billion²⁰²³. **The fossil fuel bill is France's biggest trade deficit item¹⁰⁷.**

As a result, the development of low-carbon electricity generation and the reduction of fossil fuel consumption are also an asset in terms of reducing France's energy bill and strengthening its sovereignty, but also the sovereignty of Europe.

Figure 4.23: Trends in French energy bills between 1970 and 2023



107. DGDDI, *Le chiffre du commerce extérieur – Analyse annuelle 2023, 2024*

5. Greenhouse gas emissions from the French power system reached a historic minimum in 2023

Emissions related to electricity generation in France reached 16.1 Mt_{CO2eq} in 2023, their lowest level since the early 1950s. The carbon intensity of French electricity generation is also at its lowest: it was 32 g_{CO2eq} per kilowatt hour produced in the year 2023. This general decline, after the cyclical increase in the volume of emissions observed in 2022, is the result of a relatively low volume of fossil-fuel production thanks to the improvement in the availability of low-carbon production resources and the decline in consumption. In 2023, emissions from the French power system remained among the lowest in Europe (which was also the case in 2022), weighing relatively little in the national carbon balance (less than 5%, compared with 22% for Germany, 19% for Spain and 21% on average for the European Union^{108,109}). **Even though the French electricity mix is already largely low-carbon, the challenge for the coming years lies in increasing the volume of low-carbon electricity produced to supply growing electricity requirements, which will result from the gradual phasing out of fossil fuels in high-emission sectors (transport, industry, buildings).**

5.1 French electricity generation has been largely decarbonised since the end of the 1980s, and has become even more so since the 2010s

From the second half of the 20th century, it is possible to identify four major periods for the French power system from the point of view of greenhouse gas emissions¹¹⁰:

- **from the post-war period until the end of the 1970s**, production was highly carbon-based; the significant growth in electricity consumption

(+1% per year on average), in a context of strong economic development and electrification of the country, was mainly covered by hydropower, coal and oil-fired power plants. Thus, the average intensity of electricity generation in France remained between 400 and 500 g_{CO2eq}/kWh. In 1976, annual emissions related to electricity generation in France reached nearly 100 Mt_{CO2eq};

- **during the 1980s**, the rapid commissioning of the nuclear reactors that make up the current fleet, in parallel with the continued growth in national electricity consumption (+0.4% per year on average over the decade), resulted in a very rapid decarbonisation of the French electricity mix¹¹¹. This deployment saw the fuel-oil fleet almost disappear and emissions related to coal halve between 1980 and 1990. As a result, the carbon intensity of French production has been divided by four in ten years: in 1990, it was less than 100 g_{CO2eq}/kWh;
- **between 1990 and the late 2000s**, emissions and the emission intensity of production remained relatively stable. The electricity mix was dominated by nuclear power, but a proportion (between 10 and 20 GW) of the fossil-fuel thermal plants, particularly coal-fired, was still in operation. Greenhouse gas emissions (between 20 and 40 Mt_{CO2eq}) and carbon intensity (around 75 g_{CO2eq}/kWh) remained stable over the period;
- **from the early 2010s**, with the increase in objectives in terms of reducing greenhouse gas and pollutant emissions, the fuel oil and coal-fired production plants were gradually reduced to the minimum necessary to ensure the security of supply. At the same time, gas-fired power plants, with lower emissions per unit of energy generated, have replaced them as state-of-the-art production facilities. The

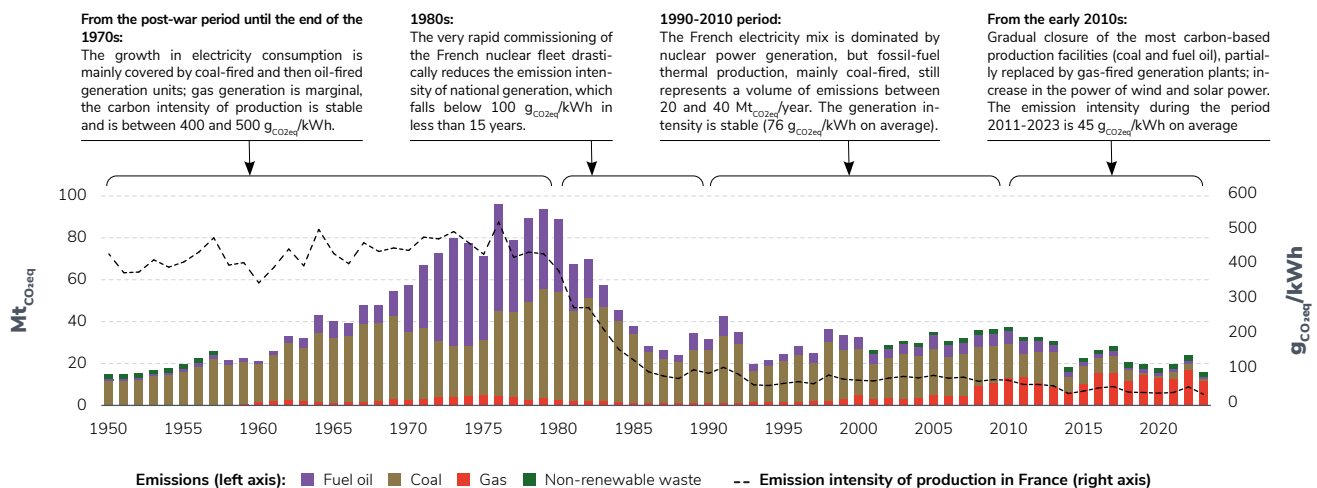
108. Sources: CITEPA, *Secten Report 2023*; European Environment Agency; Eurostat; ENTSO-E; calculations: RTE.

109. The territorial emissions of the European Union amounted to 3,735 MtCO_{2eq} in 2021 (source: *European Environmental Agency*). Emissions due to electricity generation in the European Union reached 783 MtCO_{2eq} (source: *Ember Climate, Yearly electricity data, 2024*).

110. The emission factors of the different generation mixes used for the calculation of the emissions over the entire period 1950-2023 are the current emission factors. Strictly speaking, it should be taken into account that emission factors tend to decrease (very slowly) over time with improvements in plant efficiency, changes in the quality of fossil fuels, etc. However, the approximation made here is not likely to substantially modify the results of the analysis.

111. The main objective at the time was the improvement of energy sovereignty and not the decarbonisation of the mix.

Figure 5.1: Direct greenhouse gas emissions related to electricity generation in France and emission intensity of French electricity generation between 1950 and 2023



Calculations carried out using assumptions of fuel emission factors and yields of current power plants, which may lead to an underestimation of historical emission volumes.

2010s were also marked by the strong development of wind and solar power. All these factors together contributed to further reducing the intensity of French electricity generation, which reached 45 g_{CO2eq}/kWh on average over the period.

Today, the French electricity mix is one of the most low-carbon in Europe, due to the predominance of low-carbon production sources: nuclear, hydro and more recently wind and solar power. In addition, some of the highest-emitting production facilities (coal and fuel oil) have been gradually

shut down over the last twenty years¹¹². Thus, despite relatively high per capita electricity consumption compared with comparable European countries¹¹³, emissions for electricity generation represent around 5% of France's national emissions¹¹⁴, compared with 22% for Germany, 19% for Spain and 21% on average for the European Union^{115,116}. Furthermore, France's traditionally strong export position means that interconnected European countries can import low-carbon electricity to cover part of their consumption, thereby improving the carbon balance on a European scale.

¹¹². See the chapter Europe.

¹¹³. Due in particular to the high proportion of electric heating. In 2021, consumption was about 7,200 kWh/capita in Italy, compared to 6,000 kWh/capita in Germany, 5,500 kWh/capita in the European Union, and less than 5,000 kWh/capita in Spain and Italy (source: Eurostat).

¹¹⁴. France's territorial emissions amounted to 418 Mt_{CO2eq} in 2021. – see CITEPA, *Secten report 2023*.

¹¹⁵. Sources: CITEPA, *Secten Report 2023*; European Environment Agency; Eurostat; ENTSO-E; calculations: RTE.

¹¹⁶. The territorial emissions of the European Union amounted to 3,735 Mt_{CO2eq} in 2021 (source: European Environmental Agency). Emissions due to electricity generation in the European Union reached 783 Mt_{CO2eq} (source: Ember Climate, *Yearly electricity data, 2024*).

5.2 Historically low greenhouse gas emissions thanks to a recovery in low-carbon production and a decline in consumption

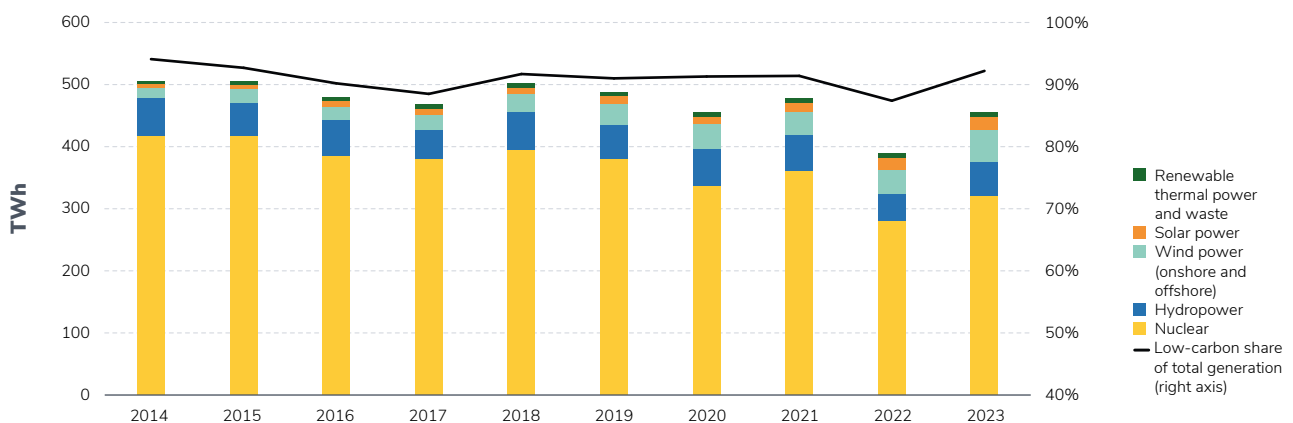
During the course of 2022, the production crisis in France led to two effects likely to affect the carbon balance of the French power system and another more broadly affecting the carbon balance of the European power system:

- the increased use of fossil fuels in France (mainly gas);

- to a lesser extent, France's significant reliance on imports from neighbouring countries, whose mix is generally more carbon-based than the French mix, to cover part of the consumption;
- from the point of view of emissions avoided abroad by French exports: the use, in neighbouring countries, of more carbon-intensive production resources than in France to compensate for the drop in imports from France.

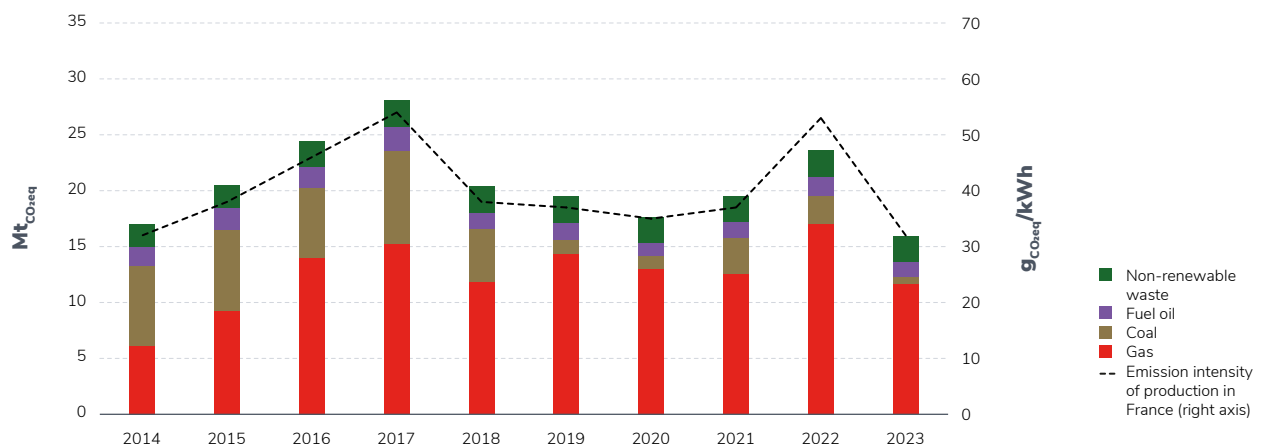
In 2023, the improvement in the availability of the French nuclear fleet and hydropower generation, the

Figure 5.2: Decarbonised electricity generation in France (left axis) and decarbonised share of total electricity generation (right axis) between 2014 and 2023



Production from household waste is considered 50% renewable. Hydropower generation is subtracted from 70% of the pumping consumption of STEP, according to European Directive 2009/28/EC.

Figure 5.3: Direct greenhouse gas emissions related to electricity generation in France (left axis) and emission intensity of French electricity generation (right axis) between 2017 and 2023



historically high volumes of wind and solar power generation and the continued decline in consumption (see the Consumption chapter), as well as the now-insignificant place of coal (see the Generation chapter), have led to a clear reduction in emissions compared to the previous year: the level of emissions has even fallen below those observed before the energy crisis, between 2018 and 2021. **Thus, total direct emissions related to electricity generation in France amounted to 16.1 Mt_{CO2eq}.** In addition, in 2023, **92% of the electricity generated in France was from low-carbon sources**, or 456 TWh. This proportion corresponds to the average for the period 2014-2021, after a low of 87% in 2022.

In 2014, coal-fired power plants still accounted for nearly 40% of greenhouse gas emissions related to electricity generation in France, or 7 Mt_{CO2eq}. **In 2023, coal-fired plants emitted less than one megatonne of CO₂ equivalent, or less than 4% of the total emissions related to electricity generation in France.**

The emission intensity of production, that is to say the emissions related to the energy generated, amounted to 32 g_{CO2eq}/kWh in 2023, down nearly 40% compared to 2022 (54 g_{CO2eq}/kWh), and even below the average for the period 2018-2021, which was around 37 g_{CO2eq}/kWh.

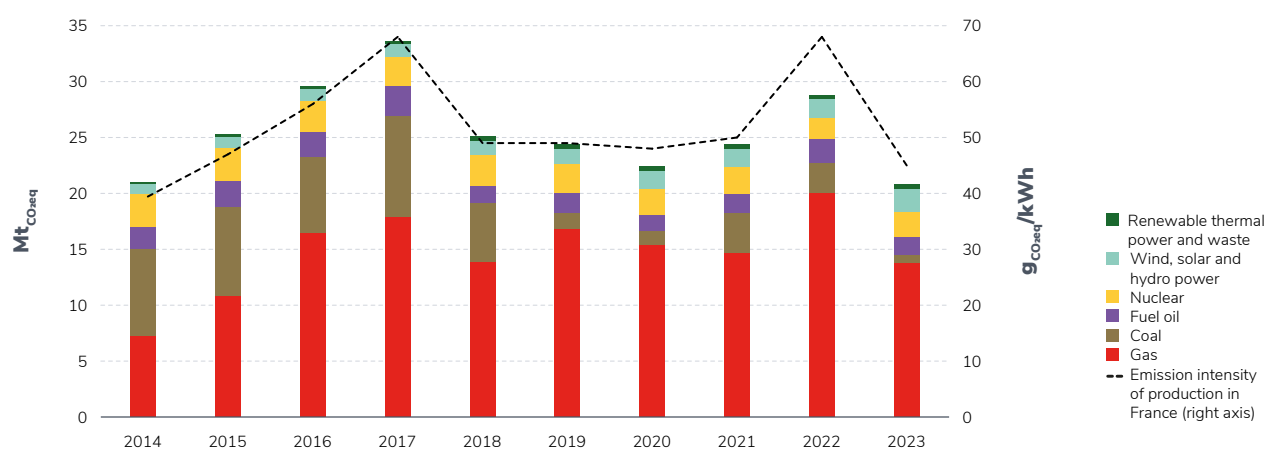
5.3 Even taking into account life-cycle emissions, emissions related to the French power system remain very low

The carbon intensity related to electricity generation can be calculated by considering only direct emissions, as is the case in Figures 5.1 to 5.3, or by including all emissions related to electricity generation over the life cycle. The latter makes it possible to take into account, in addition to the direct emissions related to combustion in power plants (for fossil fuel-fired power plants), all the emissions related to the life cycle of production facilities: from the extraction and transport of fuels and raw materials or equipment, to the construction of infrastructure allowing the generation of a given amount of energy. Some production sources, such as wind, solar and hydro power, do not cause direct emissions, but the construction of dams, the manufacture and transport of solar panels and wind turbines and their

installation, generate indirect emissions that are taken into account in this approach¹¹⁷ (for a more complete presentation and a comparison between the different methods of calculating greenhouse gas emissions, see Figure 5.5).

Taking into account life-cycle emissions, emissions related to electricity generation in France reached 22.6 Mt_{CO₂eq} in 2023, compared to 30.8 Mt_{CO₂eq} in 2022, a decrease of 27%. Just like direct emissions, life-cycle emissions remain much lower in France compared to those in other countries. In 2023, life-cycle emissions were about 40% higher than direct emissions. Despite their growing share of the electricity mix, the combined contribution of wind, solar and hydropower to life-cycle emissions from electricity generation remains very low. **In 2023, they accounted for less than 10% of the total life-cycle emissions related to electricity generation in France (2.1 Mt_{CO₂eq}) and less than 0.5% of the country's carbon footprint¹¹⁸.**

Figure 5.4: Life-cycle greenhouse gas emissions related to electricity generation in France (left axis) and intensity of French electricity generation (right axis) between 2017 and 2023



¹¹⁷. Greenhouse gas emissions over the life cycle of low-carbon energies remain very low compared to those of fossil-fuel thermal facilities: 16 g_{CO₂eq}/kWh for onshore wind power, 17 g_{CO₂eq}/kWh for offshore wind power, 43 g_{CO₂eq}/kWh for photovoltaic solar power, 7 g_{CO₂eq}/kWh for nuclear power, 6 g_{CO₂eq}/kWh for hydropower, compared to 941 g_{CO₂eq}/kWh for coal-fired power plants, 928 g_{CO₂eq}/kWh for oil-fired power plants and 389 g_{CO₂eq}/kWh for combined cycle gas power plants, which are the most efficient gas-fired power plants.

¹¹⁸. The carbon footprint refers to all emissions, both domestic and foreign, that are attributable to the national consumption of a given country. This therefore counts emissions generated abroad by the production of goods or services consumed in the country in question, but not emissions generated in the country in question by the production of goods or services that are consumed abroad. It is a concept close to the life cycle, but distinct: the carbon footprint is based on the attribution of emissions to the consumption of a given territory, while the life cycle analysis is based on the attribution of emissions to a given use, activity or object.

Figure 5.5: Summary of the concepts involved in the calculation of greenhouse gas emissions related to electricity

		Type of emissions	
		Direct emissions	Life-cycle emissions
Scope	Electricity generation	For electricity generated in fossil-fired power plants, these are emissions related to combustion. Electricity generation resources that do not use fossil fuels (wind, solar, nuclear and hydro power) do not generate direct emissions.	The life-cycle emissions analysis, or LCA (life-cycle assessment), allows us to take into account all of the emissions generated to make a certain amount of electricity available: these include all the emissions related to the extraction and transport of materials used for the construction of power plants, equipment and infrastructure in France or abroad. These emissions can take place upstream or downstream of electricity generation facilities. Life-cycle emissions include direct emissions.
	Electricity consumption	Direct emissions from electricity generation plants located on the national territory.	Life-cycle emissions attributable to electricity generated on French territory. Some of the emissions related to the upstream or downstream of the life cycle (excluding combustion) can take place abroad.
		Direct emissions from electricity generation plants located on the national territory, subtracted from the emissions generated by the generation of exported electricity, and direct emissions from plants located abroad that supply electricity consumption in France (via imports).	Life-cycle emissions attributable to electricity consumed on French territory. Life-cycle emissions of electricity generated in France but exported are not counted; life-cycle emissions of imports that supply electricity consumption in France are counted.

5.4 Even taking into account electricity imports and exports, the French power system remains largely decarbonised

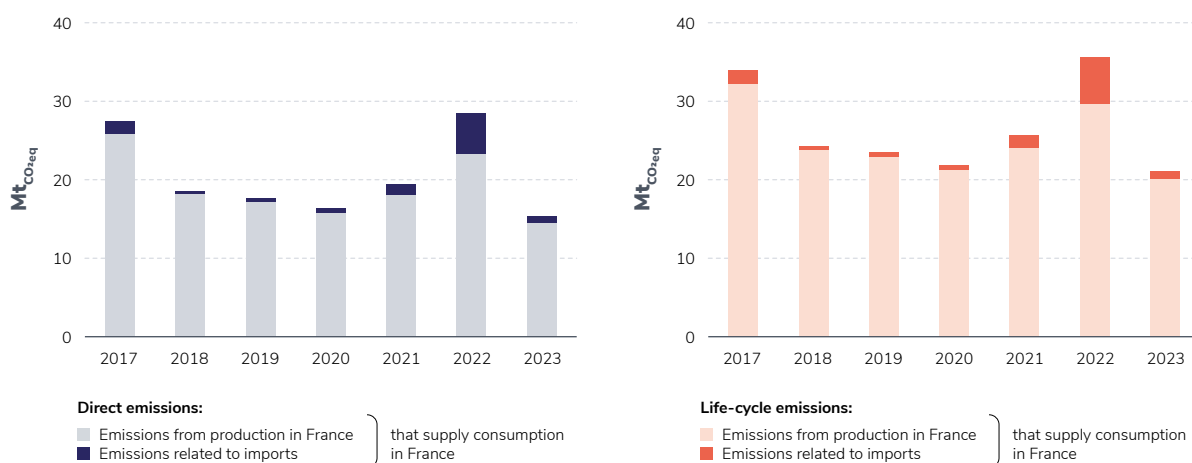
Emissions related to the French power system can be assessed according to **different scopes** (see Figure 5.5): **that of electricity generation in France**, detailed in the previous sections, but also that of **electricity consumption in France**. In addition to the share used to cover national consumption, some of the electricity generated in France is exported to other European countries. On the other hand, part of French consumption is covered by imports of electricity generated abroad, especially during periods of high consumption in winter, or when it is more economical to import from neighbouring countries (especially in the case of abundant renewable production in these countries) than to start up more expensive production facilities in France.

Emissions linked to electricity consumption in France therefore correspond to emissions from French production from which emissions linked to exports have been subtracted, and to which emissions linked to imports have been added¹¹⁹.

Depending on the ratio between the volumes of energy imported and exported, and the times at which these exchanges take place, and therefore the emissions intensity of these volumes, emissions in the consumption scope may be higher or lower than those in the generation scope. Indeed, even if electricity generation in France is more decarbonised than that in neighbouring countries, it is useful to note that, on average, more than 60% of French imports are decarbonised (see the detailed analysis in the rest of the chapter). In 2023, direct emissions within the consumption scope amounted to 15.3 Mt_{CO₂eq}, which is slightly lower than those within the generation scope (16.1 Mt_{CO₂eq}), even though in previous years, emissions within the consumption scope had been higher than those within the generation scope. Taking into account all life-cycle emissions, electricity consumption in France emitted 21 Mt_{CO₂eq} in 2023, and generation 23 Mt_{CO₂eq}.

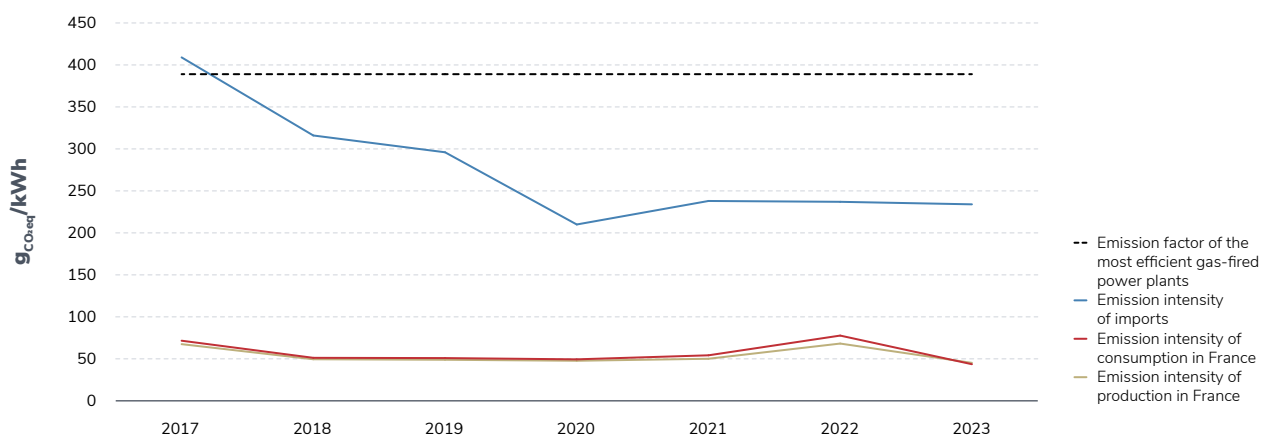
The more frequently France imports and the larger the volumes, the greater the share of emissions linked to imports in total emissions linked to consumption. This was particularly the case in 2022, when France's exchange balance was one of being a net importer, and France imported electricity

Figure 5.6: Greenhouse gas emissions related to electricity consumption in France between 2017 and 2023



119. The distinction between emissions in the generation scope and emissions in the consumption scope is similar to the distinction between territorial emissions and carbon footprint.

Figure 5.7: Carbon intensity (direct emissions) annual average of the French power system according to different scopes



almost 70% of the time: during that year, imports accounted for just under 20% of the emissions linked to French consumption. When France is mainly an exporter, despite occasional recourse to imports to cover periods of high consumption in winter (or to take advantage of high renewable production abroad), emissions linked to imports are quite insignificant. Thus, in 2023, imports represented only 5% of emissions related to electricity consumption in France, or less than 1 Mt_{CO2eq}.

The year 2022 was marked by a visible but contained increase in carbon intensity both in terms of generation and consumption, due to the relatively greater use of fossil fuels and, to a lesser extent, imports (on average more carbon-based than

French production) from neighbouring countries. Thus, the carbon intensity of electricity generation in France had increased from 37 to 54 g_{CO2eq}/kWh between 2021 and 2022, and the carbon intensity of consumption from 41 to 62 g_{CO2eq}/kWh. In 2023, overall, they returned to levels close to or even slightly lower than those before the energy crisis: 32 g_{CO2eq}/kWh for generation and 31 g_{CO2eq}/kWh for consumption.

The average carbon content of electricity imported by France also fell slightly in 2023 compared to the years marked by the energy crisis, 2021 and 2022. Overall, over the period 2017-2023, it fell significantly, reflecting the decarbonisation trend of European countries (see the Europe chapter).

5.5 On an hourly basis, the French power system is low-carbon most of the time, with a few peaks in carbon intensity

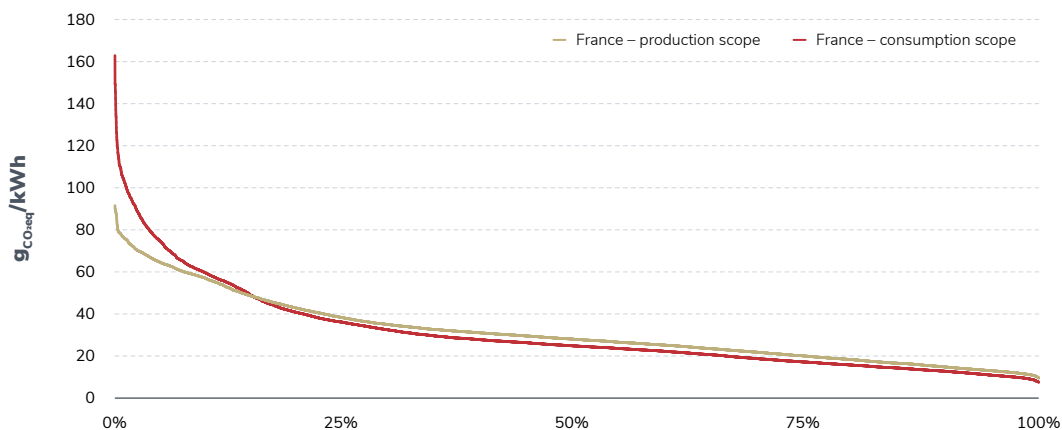
A detailed analysis of the carbon intensity of generation and consumption hour by hour makes it possible to highlight large differences between the maximum and minimum values during the year, but also the one-off nature of these extreme values. This applies to both the highest values – when high-carbon resources are used abroad to ensure the supply-demand balance – and the lowest values – which generally correspond to situations where French low-carbon production is largely surplus to domestic consumption, and the surplus is exported. The hourly analysis is complementary to analyses on longer time scales; together, they illustrate the cyclical, structural and specific dynamics of the French power system in terms of greenhouse gas emissions.

As with emissions volumes, emissions intensity for the consumption scope may be higher or lower than that for the generation scope; in previous years, it was more often higher. In 2023, on the other hand, the (direct) emissions intensity for the consumption scope was almost 80% lower than the intensity assessed for the generation scope.

Of the 20% of the time when the carbon intensity of consumption was greater than that of generation, the difference between the two was all the greater as we approached the hourly *maximums* for the two scopes. On these time scales, the difference between the two scopes is simply explained by the inclusion of imports: when the intensity is high on the French generation scope, this means that carbon resources have been very heavily used in France, which tends to happen when the balance between electricity supply and demand is strained. However, it is precisely in these situations that the share of imports in the coverage of French consumption is the largest. As imports are on average more carbon-based than French generation, they feed the difference between the two scopes and the gap then becomes larger.

Three-quarters of the time, the carbon intensity in direct emissions of French production is less than 40 g_{CO2eq}/kWh; a quarter of the time, it is even less than 20 g_{CO2eq}/kWh, a particularly low value. Over the quarter of the time when the intensity is highest, it is between 40 and 80 g_{CO2eq}/kWh, a relatively high range for the French power system, but which still remains low compared to the average intensity of production in other comparable countries (see the Europe chapter). Finally, the carbon intensity of electricity generation in France very rarely

Figure 5.8: Monotonous carbon intensity (direct emissions) of French generation and consumption



Reading: Over 25% of the hours of the year 2023, the carbon intensity of consumption in France was greater than 35 g_{CO2eq}/kWh. At most, it reached 162 g_{CO2eq}/kWh, and has always been greater than 8 g_{CO2eq}/kWh.

exceeds $80 \text{ g}_{\text{CO}_2\text{eq}}/\text{kWh}$ (less than 0.3% of the time, i.e., 30 hours over the year); at the consumption level, the direct emissions intensity exceeds less than 0.3% of the time the value of $120 \text{ g}_{\text{CO}_2\text{eq}}/\text{kWh}$; these values can be compared, for example, to the intensity of production facilities that would be

entirely composed of the most efficient gas power plants, i.e. $331 \text{ g}_{\text{CO}_2\text{eq}}/\text{kWh}$. Thus, even during hours of high consumption, when production is the most carbon-based and the use of imports is high, low-carbon production represents an important base for French electricity generation.

5.6 The French power system has returned to its role as a contributor to the decarbonisation of the European power system

France's largely low-carbon electricity exports contribute not only to the carbon performance of the national power system, but also to those of other countries with which France is interconnected via the European grid. Thus, using French export volumes and comparing the intensity of the respective generation mixes with that of France on an hour-by-hour basis, it is possible to determine the quantity of emissions "avoided" abroad as a result of the reduced call on thermal power plants by these countries, thanks to the use of imports from France¹²⁰. In total, **since 2017, French electricity exports have prevented the emission of nearly 150 Mt_{CO2eq} in Europe, half of which in Italy.** Figure 5.8 presents these volumes of emissions aggregated on an annual scale, by country, within the scope of the extended European network as presented in the Exchanges chapter.

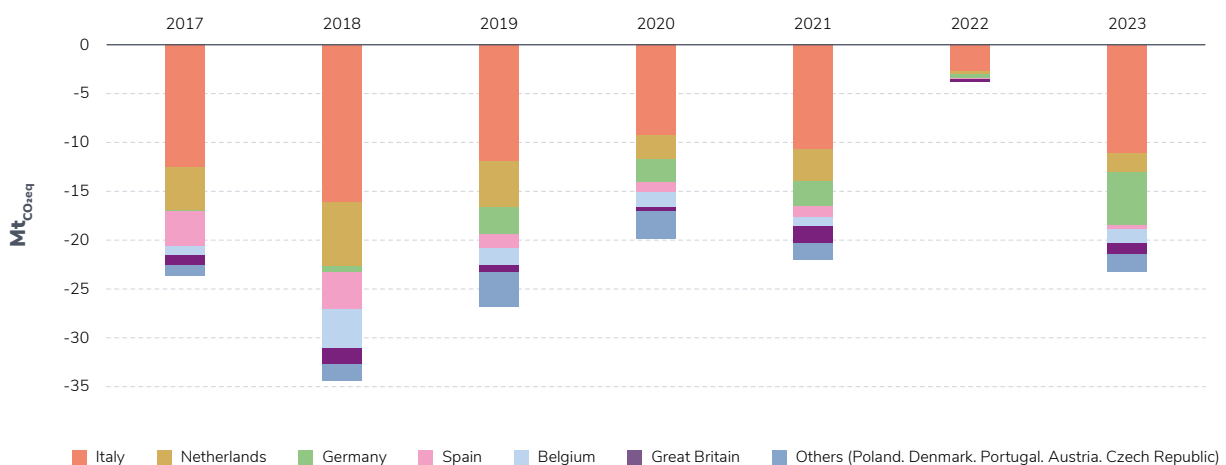
The volumes of emissions avoided abroad depend essentially on two factors:

- the proportion of time when the French exchange balance is a net exporter, both in terms of overall and bilateral balance, and the volumes exported;
- the difference in carbon intensity between France and other countries: the smaller this difference is due to the gradual decarbonisation of the mixes of other countries (see the Europe chapter), the less significant the contribution of French exports to decarbonisation.

Thus, the volume of emissions avoided in 2022 by French exports was very much lower than in previous years, due to France's position as a net importer for a large part of the time. In 2023, thanks to the recovery in exports (see the Exchanges chapter), emissions avoided abroad returned to a level close to that of the years before the energy crisis, and amounted to 23 Mt_{CO2eq}.

The analysis also shows a slight decrease (in absolute value) between emissions avoided in 2018 (after a low in 2017 due to more carbon-based French production) and those avoided in 2021 and 2023, which fall from a total of 35 Mt_{CO2eq} to about 20 Mt_{CO2eq}. This drop is not due to a reduction in

Figure 5.9: Reduction of emissions related to electricity generation in other European countries thanks to exports from France



¹²⁰. Strictly speaking, this is a minority of the emissions avoided: it is likely that the production facilities that would have been used to replace French imports would have a higher carbon content than the average mix in the importing country at the time in question.

the volume of exports, but rather to a drop in the carbon intensity of the generation mix of most of the European countries taken into account in the analysis, and consequently to a reduction in the carbon intensity gap between the production of these countries and French production. Thus, for example, the difference between the average intensities of the Italian and French generation mix fell from 356 to 248 g_{CO2eq}/kWh between 2018 and 2023, resulting in a reduction in annual avoided

emissions of nearly 5 Mt_{CO2eq} despite maintaining export volumes. Emissions avoided in Spain, which still amounted to almost 5 Mt_{CO2eq} in 2018, were almost negligible in 2023: this is explained by the combined effect of the decarbonisation of the Spanish generation mix (see *Europe* chapter) and the more balanced position from the point of view of exchanges between France and Spain (see *Exchanges* chapter).

5.7 French imports are mainly low carbon

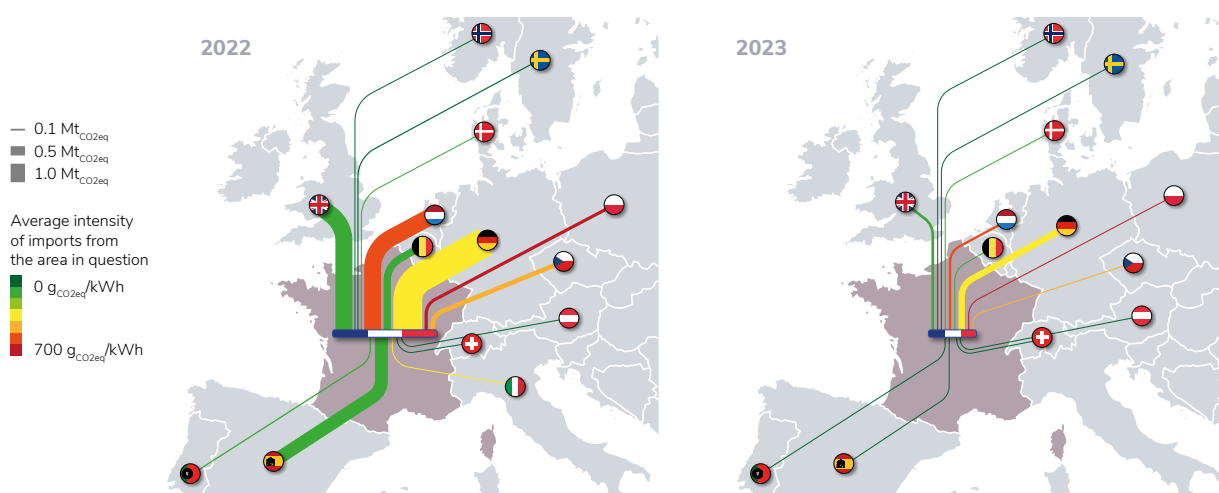
The assessment of emissions at the consumption level, mentioned above, requires an analysis of the carbon content of French imports, which is carried out using the same approach at the extended European level (that is to say, also taking into account exchanges between France's neighbours and their own neighbours, and so on) as that presented in the Exchanges¹²¹ chapter. This analysis shows that, even though the production of a large proportion of European countries is more carbon-intensive than French production, and the emissions intensity of imports is generally higher than the emissions intensity of French production, imported volumes still include a significant proportion of low-carbon energy. Indeed, **in 2023, 64% of imported electricity volumes were low carbon**; in 2022, this rate was close to 60%, reflecting the ongoing decarbonisation trend of the European power system (see Europe chapter).

Emissions linked to imports were characterised by a one-off increase in 2022 (5.2 Mt_{CO2eq}),

as mentioned in the analysis of emissions at the consumption level. **In 2023, they represented 0.8 Mt_{CO2eq}**, a level closer to that of the years preceding the energy crisis.

By 2022, France had mainly imported electricity from Great Britain and Spain (39% of the total for the two considered together, or almost 10 TWh). Emissions linked to these imports remained contained, both in volume (1.5 Mt_{CO2eq} for both) and in intensity (respectively 191 and 147 g_{CO2eq}/kWh on average). Emissions linked to imports from countries whose production is highly carbon-based, such as the Netherlands, Poland or the Czech Republic, remained low in volume (1.4 Mt_{CO2eq}). Emissions linked to imports from Germany also remained moderate: about 1.5 Mt_{CO2eq}, or less than a third of emissions linked to imports and less than 5% of total emissions linked to French electricity consumption. This relatively low volume as far as Germany is concerned must be seen in the light of the essential contribution of these exchanges – as well as those with other countries – to France's security of supply.

Figure 5.10: Cartography of the volumes of direct emissions linked to electricity imports from neighbouring countries in 2022 and 2023



121. Hörsch, J et al., Flow tracing as a tool set for the analysis of networked large-scale renewable power systems, 2017.

6. The electrification of uses is an essential lever for France and Europe to achieve carbon neutrality in 2050

The decarbonisation efforts undertaken by France and the European Union, within the framework of the Paris Agreement at the global level, the Green Deal at the European level, or the Climate Law¹²² at the national level, **aims to achieve carbon neutrality by 2050**. In the shorter term, the intermediate objective at the European level is to reduce the Union's net territorial emissions by at least 55% compared with 1990 levels. This ambition is set out in concrete terms, for all sectors, in the Fit-for-55 legislative package, most of the texts of which have now been adopted, and aim to set the Union, without delay, on the trajectory needed to achieve the 2030 and 2050 objectives.

The French power system is now largely decarbonised (see the Emissions chapter): its emissions contribute little to the country's overall carbon balance, which represents an asset in terms of achieving climate goals. **However, the French economy and today's non-electric end-use consumption remain very dependent on fossil fuels**, and generate significant emissions: total greenhouse gas emissions, from all sources, on French territory amounted to 415 Mt_{CO₂eq} in 2021, or 6.1 t_{CO₂eq}/capita^{123,124}. The balance is higher if we consider the emissions linked to the country's domestic demand (using a "carbon footprint" approach), which takes into account the carbon content of imported products while subtracting the carbon content of exported products. As the French economy, like that of most OECD countries, is heavily tertiarised, imports account for a significant proportion of the carbon

footprint. In 2021, it amounted to 575 Mt_{CO₂eq}, or 8.4 t_{CO₂eq}/capita. The relocation of certain types of production on French soil at the same time as the decarbonisation of end-use consumption progresses could therefore help to reduce overall emissions, while having a limited effect on the increase in local emissions.

A transformation necessary to achieve carbon neutrality by 2050, common to all prospective scenarios for France or other European countries, is the massive electrification of uses¹²⁵, that is to say, the transfer to electricity of a significant proportion of energy consumption today satisfied by fossil fuels¹²⁶. In particular, electrification is one of the decarbonisation levers identified in France's national low-carbon strategy. Electrification can be direct, or indirect, in particular through the use of water electrolysis for the production of hydrogen.

With regard to electrification, the challenge for countries whose power systems are still relatively carbon-intensive is twofold: to decarbonise electricity production while increasing its level. **For France, given the largely decarbonised power system and the transition rates necessary to achieve climate goals, the initial situation is different, but the challenges are similar: it is a question of basing the electrification of uses on a power system whose production must grow massively while remaining permanently decarbonised.** In the short and medium term, that is to say, by 2035, the options for developing the

122. Légifrance, Law No. 2021-1104 of 22 August 2021 on the fight against climate change and strengthening resilience to its effects, 2021

123. CITEPA, Secten report 2023 and INSEE, Demographic assessment 2023.

124. France's per capita emissions are lower than those of countries such as the Netherlands, Belgium (9.6 t_{CO₂eq}/capita both) or Germany (9.1 t_{CO₂eq}/capita), but are comparable to those of countries such as Italy (7.1 t_{CO₂eq}/capita) and Spain (6.1 t_{CO₂eq}/capita). The territorial emissions per capita of the European Union amounted to 7.8 t_{CO₂eq}/capita in 2021 (source: European Environment Agency, National emissions reported to the UNFCCC and to the EU Greenhouse Gas Monitoring Mechanism, 2021 data). These figures do not take into account extraterritorial emissions or international aviation (in other words, it is not a measurement of the carbon footprint, which is higher).

125. For a summary of the scenarios envisaged by the public authorities in a selection of European countries, see RTE, Energy futures for 2050 – Chapter 6: Europe, and 2023-2035 Generation Adequacy Report – Chapter 5: Europe.

126. The degree of electrification envisaged may vary according to national strategies, but it remains high for most European countries. Other decarbonisation levers include the use of biomass (biogas, wood or biofuels), as well as other synthetic vectors (hydrogen, e-fuels) produced from electricity, which make it possible to satisfy uses that cannot be met by electricity directly (this is known as indirect electrification).

generation mix are limited¹²⁷, and the increase in low-carbon production will have to go through the optimisation of the operation of the current nuclear fleet, to maximise its production, as well as through an acceleration of the development of renewable energies (see the *Production* chapter) to support the decarbonisation of uses.

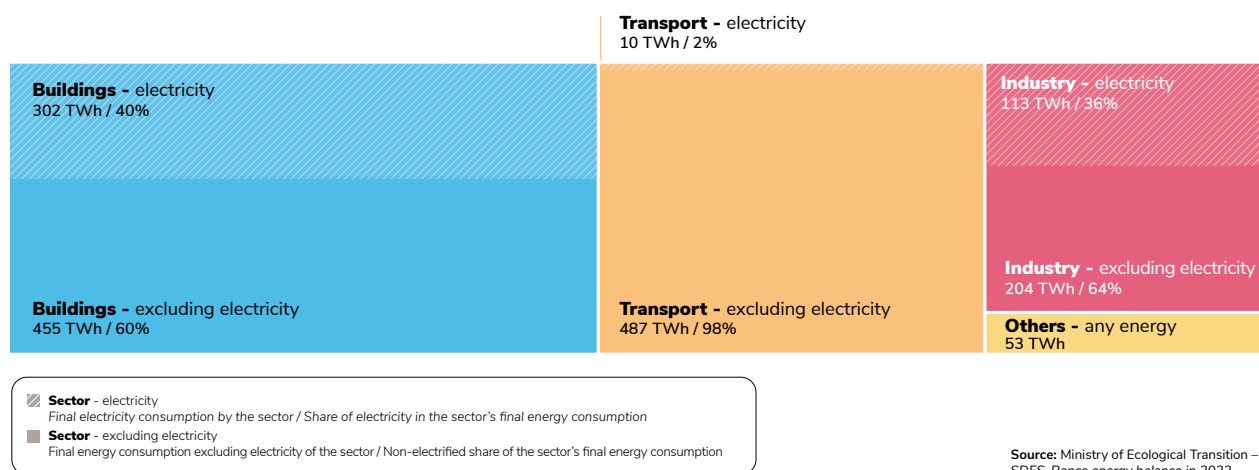
For several years, RTE has been studying in depth the various levers that can reduce emissions from the various economic sectors that can benefit from the electrification of uses: transport¹²⁸, heating¹²⁹, industry and hydrogen production¹³⁰. In particular, the analyses carried out within the framework of the *Energy futures for 2050* concluded that about half of the reduction in territorial emissions necessary to achieve carbon neutrality in 2050 could be driven by the transfer of uses to electricity¹³¹.

In this context, it is useful to monitor the development of the various electrification methods, the

effects of which should become visible on electricity consumption in the years to come.

The analysis detailed here focuses on three sectors that together account for 68% of France's territorial emissions and 71% of final energy consumption^{132,133}: transport (31% of emissions, 30% of final consumption), manufacturing (19% of emissions, 13% of final consumption) and residential and commercial buildings (18% of emissions, 30% of final consumption). In 2021, the energy industry accounted for about 10% of territorial emissions. Half of these are related to electricity generation, which is already largely decarbonised (see the *Emissions* chapter), although progress is still possible; the other half comes mainly from oil refining, urban heating and waste-to-energy recovery. The rest of France's territorial emissions come from agriculture (77 Mt_{CO2eq}, 18%) and waste treatment (15 Mt_{CO2eq}, 4%).

Figure 6.1: Distribution of final energy consumption by sector in France in 2021, and the share of electricity in the final consumption of each of the sectors



¹²⁷. RTE, *Energy futures for 2050 – Chapter 4: Electricity production* and *2023-2035 Generation Adequacy Report – Main results*.

¹²⁸. RTE, *Challenges of the development of electromobility for the power system*, 2019

¹²⁹. RTE and ADEME, *Reduction of CO₂ emissions, impact on the power system: what contribution will heating in buildings make by 2035*, 2020

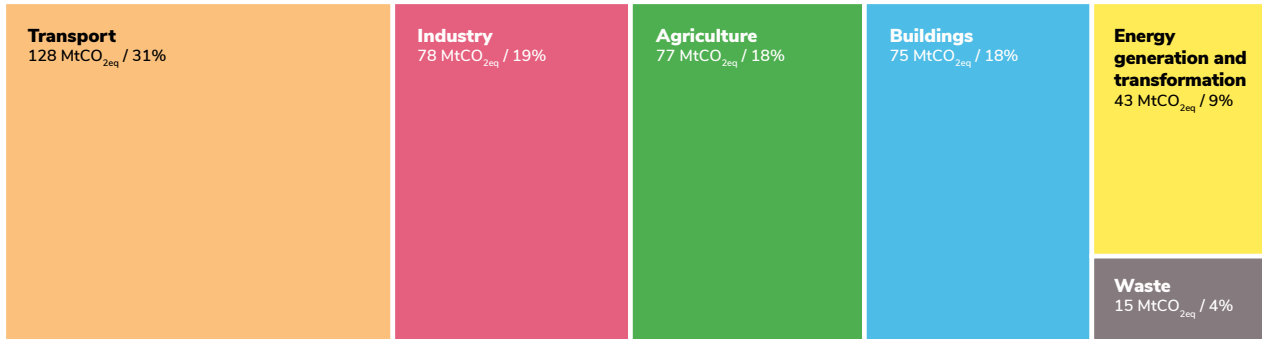
¹³⁰. RTE, *The transition to low-carbon hydrogen*, 2019

¹³¹. Considering the scope of the carbon footprint, the contribution of electrification was estimated at about 35% in the *Energy futures for 2050*.

¹³². CITEPA accounts for emissions related to electricity generation in the *Energy Industry* sector. Here, in order for the comparison between the share of emissions and the share of final energy consumption to be valid, it is therefore the final energy consumption excluding electricity of each of the sectors that is considered.

¹³³. CITEPA, *Secten report 2023* and Ministry of Ecological Transition – SDES, *France's energy balance in 2022*; calculations: RTE.

Figure 6.2: Distribution of greenhouse gas emissions by sector in France in 2021



In the methodology used by CITEPA, emissions related to energy use (in particular, fuel combustion) are accounted for within the emissions of each sector. Electricity does not generate emissions in the use phase: emissions related to electricity generation are accounted for in the aggregate - "Energy generation and transformation".

Source: CITEPA. Secten report 2023.

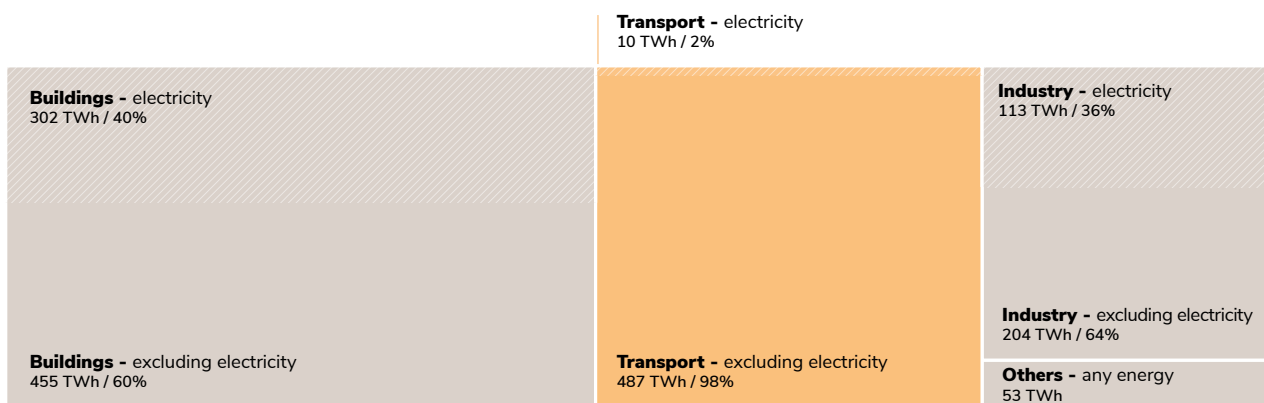
6.1 The market share of electrical vehicles continued to rise, but their share in the national fleet remains small

6.1.1 Context and stakes

The transport sector is by far the largest emitter of greenhouse gases in France: 31% of territorial emissions in 2021. Road transport alone accounts for 29% of the country's territorial emissions.

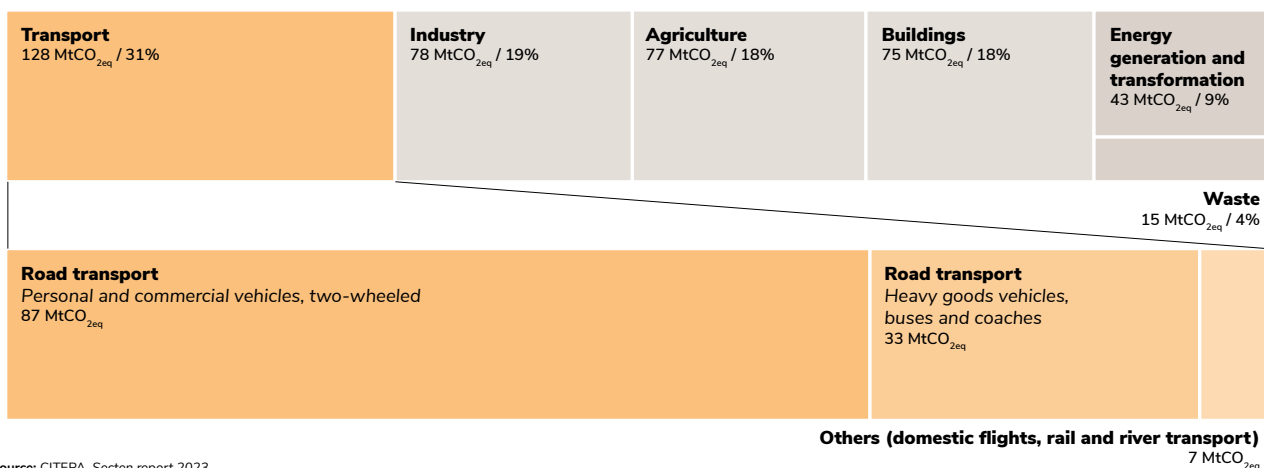
There are two main axes to decarbonise the transport sector: the decarbonisation of energy and the reduction of consumption. In the first case, electrification is one of the main and most effective means of replacing fossil fuels, but in certain uses such as heavy mobility or air transport, this vector is not necessarily the most suitable. The reduction of energy consumption, on the other hand, can be achieved through the renewal of the fleet with more efficient vehicles but also through sobriety measures. The modal shift, for example, is one of them; it concerns both the transport of passengers,

Figure 6.3: Final transport energy consumption in France in 2021, and the share of electricity in the sector's final consumption



Source: Ministry of Ecological Transition – SDES, France's energy balance in 2022.

Figure 6.4: Breakdown of transport emissions by sub-sector, in France in 2021



Source: CITEPA, Secten report 2023.

with the reduction of the share of the private car in favour of that of public transport, cycling, walking or other so-called “soft” modes, and freight transport, with a reduction in the share of heavy goods vehicles in favour of rail or river transport. The size and weight of vehicles, carpooling or the reduction of travel also reduce consumption and therefore emissions. The latter is largely dependent on transformations in terms of land use planning, the organisation of work or the modes of production and consumption of goods, with a focus on the consumption of locally produced goods.

For each country, the share given to the different levers in the definition of decarbonisation objectives and trajectories depends on many factors such as geography (human and physical) or economic considerations (the importance of the national automotive industry, the structure of employment in the country, the cost of electric vehicles, household income and financing conditions, etc.), and, ultimately, political choices. In France, public policies are now mainly oriented towards electrification¹³⁴.

There are currently obstacles to large-scale electrification of personal vehicles, the first of which is economic: despite substantial fuel savings over the lifetime of the vehicle, the purchase cost of personal electric vehicles is still high compared with that of combustion-powered vehicles, which reduces the share of the population having access to them. Moreover, a second-hand market has only started to develop relatively recently (which is normal given the lifespan of vehicles). A second barrier is the perceived constraints associated with the switch to electric vehicles: fears remain high

about range, even if battery capacity improves, and in particular about the adequacy of the network of charging stations for different uses¹³⁵.

To facilitate access to electric vehicles, the French government implements purchase subsidies of several types¹³⁶; today, the electric vehicle market is still dependent, to a certain degree, on these subsidies¹³⁷. At the same time, the development of the infrastructure necessary for the widespread use of electric vehicles, that is to say the development of a sufficiently dense network of public charging stations on the main roads, is encouraged and supported¹³⁸.

Electric vehicles are also highly exposed to changes in the global geopolitical context, with the rise of protectionism, and the questioning, by some players, of free trade; these changes reconfigure the value chains and therefore the economic data of the problem (see also the Industry section). Another, more specific and related issue is the competition for resources, particularly mineral resources, which are necessary for the energy transition. One example, which particularly affects the decarbonisation of transport, is lithium, which is used in the manufacture of lithium-ion batteries, and whose production and processing are now concentrated in a few countries¹³⁹. For Europe, the decarbonisation of the sector will require finding the right balance between improving the economic competitiveness of electric vehicles to promote their large-scale deployment, and the securing of supply chains that today involve foreign players with different interests (China in the first place, but also, with different issues, the United States).

134. See for example the [draft French Strategy for Energy and Climate](#), published for public consultation in November 2023, specifically Part 4 “The 5 objectives of the Multiannual Energy Plan”, and the guidelines presented in Objective 1 “Reduce our energy consumption”.

135. See the joint study by RTE-Ipsos, [Understanding and managing electrification by 2035 – Chapter 3: Moving](#), 2023.

136. Two devices coexist: the ecological bonus for purchase (see Energy Code, “[Single section: Aids for the purchase or rental of low-polluting vehicles \(Articles D251-1 to D251-13\)](#)” and [Service-Public.fr, Ecological bonus for a car](#), 2023), and the rental aid: [Légifrance, Decree No 2023-1183 of 14 December 2023 relating to the establishment of aid for the rental, for a period greater than or equal to three years, of an electric passenger car](#), 2023, introduced very recently.

137. The slowdown in the growth of the market share of electric vehicles in Germany (see Figure 6.5), immediately following the reform, at the end of 2023, of subsidies for the purchase of private electric vehicles, tends to support this assertion.

138. This is the subject, among other things, of the European Union regulation on infrastructure for alternative fuels, known as “AFIR”, adopted during the year 2023 as part of the Fit-for-55 package. See [Council of the European Union, Press release, Infrastructure for alternative fuels: the Council adopts a new law to increase the number of charging and refuelling stations in Europe](#), 2023.

139. On lithium-related issues in the context of the energy transition, see for example [Columbia Center on Global Energy Policy, Fact Sheet: Lithium Supply in the Energy Transition](#), 2023 or RTE, [Energy Futures for 2050 – Chapter 12: “Environmental Analysis”](#), 2022.

6.1.2 In 2023, the market share of all-electric vehicles in France has increased significantly, and exceeds those in Germany and the United Kingdom

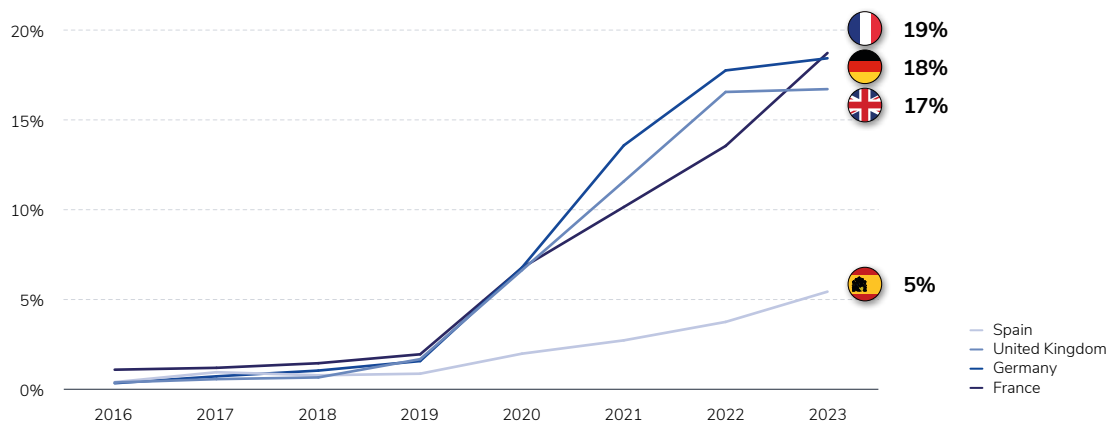
In 2023, the market share of all-electric vehicles¹⁴⁰ in France has increased significantly. In 2022, it was less than 15%; in 2023, it reached 19%, that is to say that almost one in five vehicles sold in France in 2023 was 100% electric. For the first time since 2019, when sales of electric vehicles were still marginal, this share exceeded that found in Germany (18%), where the reform of purchase subsidies has led to a stagnation of market share, and the United Kingdom (17%), where market share has also not increased in 2023. In Spain, the market share of electric vehicles continues to be much lower¹⁴¹: in 2023, it was around 5%. The number of all-electric vehicles running in France exceeded one million in 2023. While the market share of these vehicles in the new car market is an important indicator, and its growth is encouraging, it should be remembered that the renewal of the car fleet, which is composed

of around 40 million vehicles in circulation in the country, is characterised by a certain inertia¹⁴². Thus, the share of electric vehicles of the total in France is about 2.5% (the proportions are similar in Germany and the United Kingdom).

Despite a position in the fleet that is still quite marginal, light electric vehicles have already prevented the emission of 4 Mt_{CO2eq} since 2013, of which more than a quarter (one million tonnes of CO₂ equivalent) in the year 2023 alone. This assessment, based on the assumption of batteries manufactured in Asia, could be further improved if they were manufactured in France (see *Industry*).

At the same time, the development of charging infrastructure continued in 2023. The number of vehicles per public charging station installed in France, which is used to assess whether the network is meeting needs, has remained below the indicative ceiling of 10 vehicles per charging station recommended by the European Commission. The AFIR regulation, adopted in 2023 as part of

Figure 6.5: Market shares of all-electric vehicles in a selection of European countries between 2016 and 2023



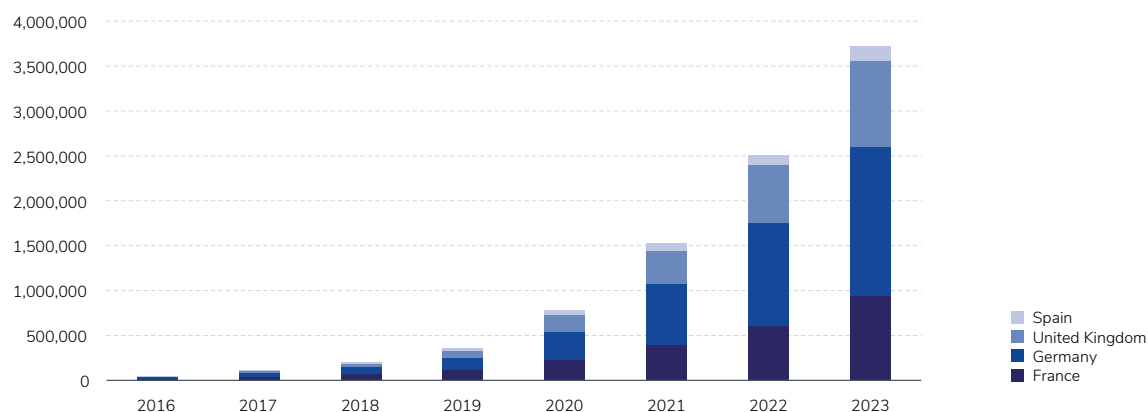
Source: Avere-France, Registration barometer; Argus, European car registrations database

¹⁴⁰. Subsequently, "electric vehicle" or "electric car" will be used for simplicity to indicate 100% electric vehicles or cars (therefore excluding plug-in hybrid vehicles).

¹⁴¹. Possible explanations lie in the development of charging infrastructure, considered insufficient by the automotive sector (*Asociación Española de Fabricantes de Automóviles y Camiones, Informe Anual de Vehículo Electrificado, 2023*) and in economic accessibility (GDP/capita is generally correlated with the market share of electric vehicles).

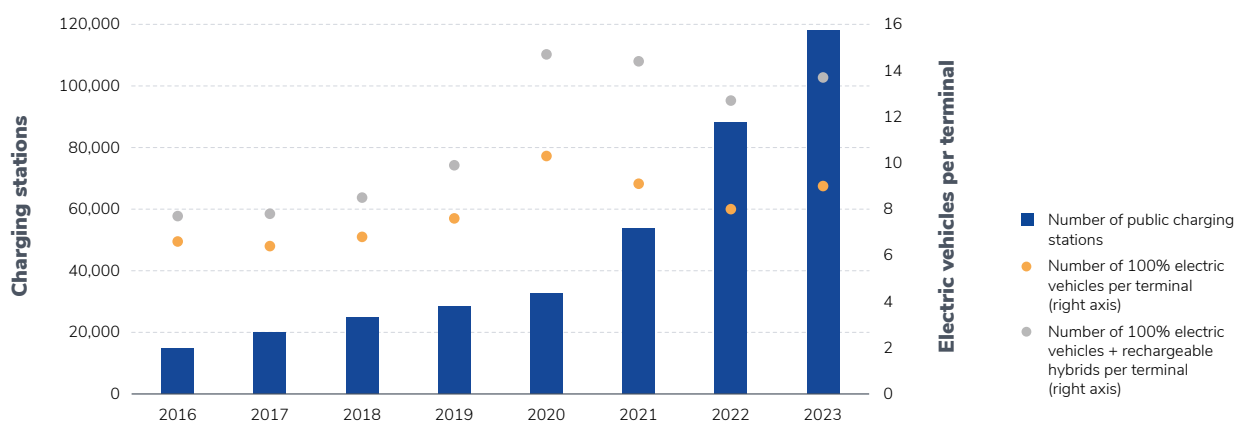
¹⁴². The lifespan of a car in France today is about 15 years.

Figure 6.6: Cumulative number of all-electric vehicles in a selection of European countries between 2016 and 2023



Source: Avere-France, Registration barometer; Argus, European car registrations database

Figure 6.7: Public charging infrastructure development in France between 2016 and 2023



Source: Avere-France, Charging barometer; calculations: RTE

the Fit-for-55 legislative package, also defines a spatial density criterion for public charging stations

of at least one station every 60 kilometres on the main European road network¹⁴³.

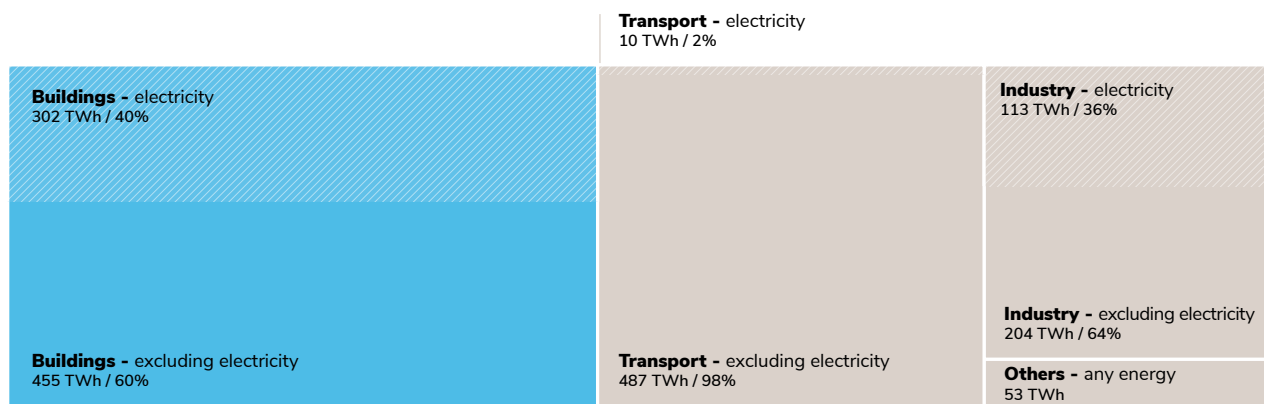
¹⁴³. As formally defined in the Trans-European Transport Networks Regulation (TEN-T, analogous to the Trans-European Energy Networks Regulation, the TEN-E). See European Commission, Trans-European Transport Network (TEN-T).

6.2 The decarbonization of buildings needs to gather strength to reach public targets

Improving the environmental performance of residential buildings essentially relies on two levers:

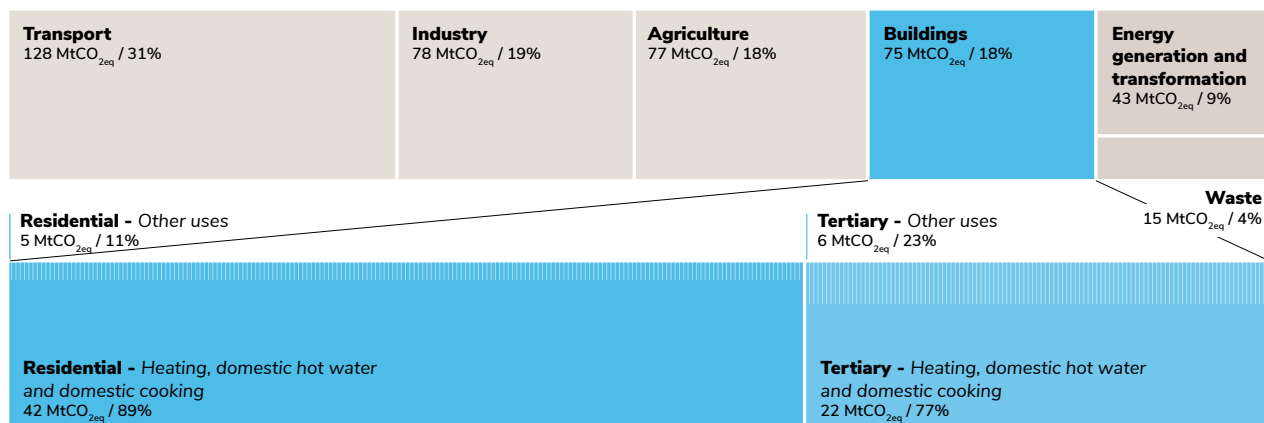
switching to a low-carbon heating system (including electricity), and thermal renovation¹⁴⁴. The joint implementation of these two levers makes it possible on the one hand to consume less energy and on the other hand to use low-carbon energy to heat the same home.

Figure 6.8: Final energy consumption of buildings in France in 2021, and the share of electricity in the sector's final consumption



Source: Ministry of Ecological Transition – SDES, Rance energy balance in 2022.

Figure 6.9: Breakdown of building emissions by sub-sector in France, 2021



Source: CITEPA, Secten report 2023.

¹⁴⁴. According to an analysis carried out by RTE as part of the "Bilan prévisionnel 2023" (Generation Adequacy Report), the transition from gas or oil-fired heating methods to low-carbon, i.e., essentially electric, heating methods, represents around 80% of the potential reduction in greenhouse gas emissions in the sector by 2035.

6.2.1 By 2022, electric heating, essentially represented by heat pumps, will once again be the mainstay of new residential construction

In 2022, for the first time since 2010, more electric heating systems were installed in the new building stock than non-electric systems¹⁴⁵. During the 2010 decade, the increase in sales of heat pumps was slower than the decrease in sales of electric radiators: the market share of electric systems therefore initially fell, reaching less than a third in 2014. The growth in sales of heat pumps in 2022 then enabled electric systems to be prevalent again in new buildings for the first time since 2010.

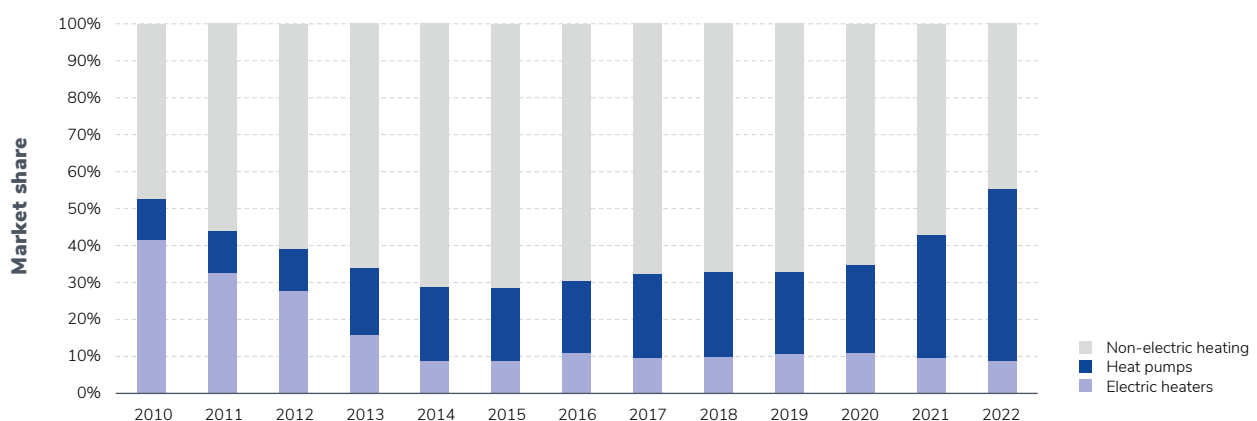
Unlike in 2010, almost 85% of electric heating systems installed in 2022 were heat pumps, and 15% radiators; in 2010, the proportions were reversed. As long as temperatures do not fall to very low levels (close to zero or lower), heat pumps are much more efficient from an energy point of view than simple radiators, which is an asset for reducing the total energy needs (all energies combined) in the case of replacing a gas or fuel oil system with a heat pump¹⁴⁶.

6.2.2 In 2023, the rate of thermal renovations of residential buildings fell for the second year in a row after the 2021 maximum

The other lever, which is fundamental and complementary to electrification with a view to decarbonising energy consumption for heating, is the thermal insulation of buildings.

In France, support for thermal renovation of the housing stock mainly takes the form of a programme of financial assistance for households implemented by the French National Housing Agency (ANAH). The annual number of renovations as well as the amount of aid granted makes it possible to monitor the deployment of the programme. After an accumulated delay in the first years of the programme, the momentum quickly accelerated from 2021 onwards. Over the last three years, on average, nearly 600,000 renovations per year have been carried out (with, however, a decline two years in a row in 2022 and 2023). This pace will have to be maintained over the period 2024-2030 to reach the objective of 370,000 renovations per year on average over the period 2015-2030, as set out in the PPE 2019-2028^{147,148}.

Figure 6.10: Market shares of the various heating methods in new residential buildings between 2010 and 2023



Source: Bâti-étude 2023

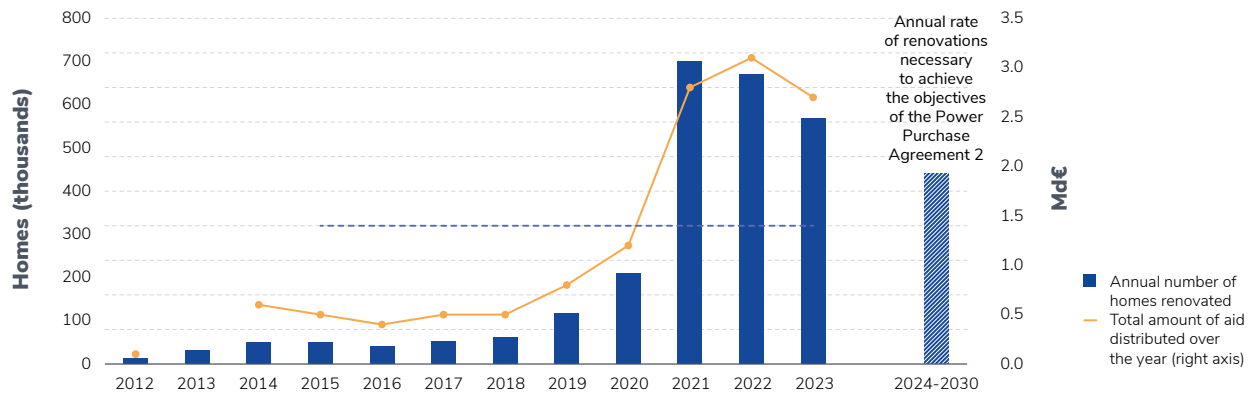
¹⁴⁵. Building-study, *The energy of heating*, 2023

¹⁴⁶. In some very special situations, the installation of a heat pump is simply not technically possible.

¹⁴⁷. The government recently set an indicative target of 700,000 renovations for 2024, excluding the PPE.

¹⁴⁸. In the broadest sense, the term "thermal renovation" refers to insulation work, but can also include the replacement of the heating system. The figures of the French National Housing Agency (ANAH), presented here, do not distinguish between the two.

Figure 6.11: Changes in the number of thermal renovations per year in France, and the amount of thermal renovation aid distributed by the French National Housing Agency between 2012 and 2023



Source: French National Housing Agency. 2012-2023 key figures

The total number of renovations carried out as part of the public thermal renovation programme for buildings masks a diversity of types and completeness of work, which have different effects in terms of energy savings and energy efficiency gains, and therefore, ultimately, emissions avoided. The so-called “major” renovations refer to those that are the most complete, and have the biggest effect. In 2023, these are up slightly compared to 2022, both in absolute number and in proportion:

72,000 complete renovations in 2023, representing 13% of all energy renovations for the year, compared to 66,000 in 2022 (10% of the total).

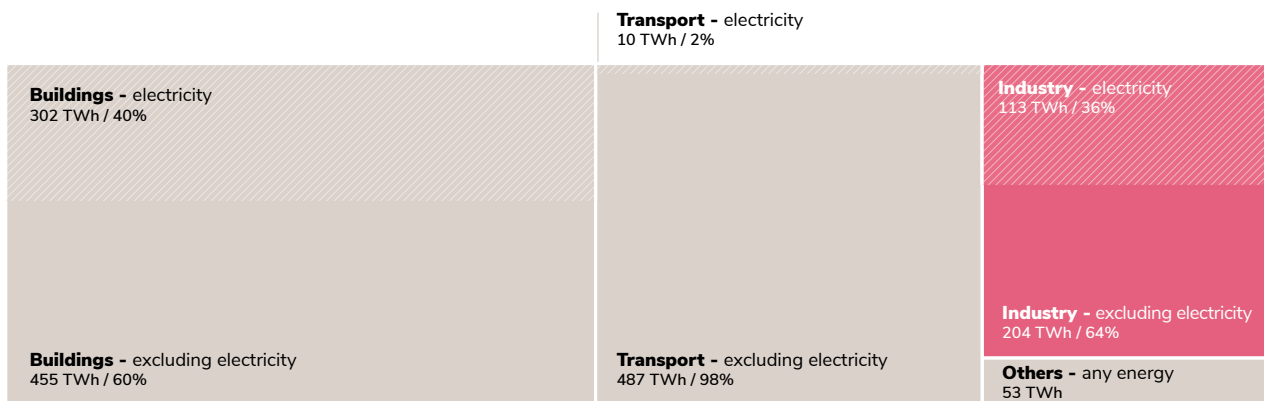
Finally, with regard to the buildings sector, a third important lever should be mentioned: sobriety (that is to say, essentially, lowering the setpoint temperature for heating), which makes it possible to consume less.

6.3 The electrification of industry, an essential lever to support the reindustrialisation of France

Despite a relative decline in its weight in France's territorial emissions over the last decades, industry still accounts for a significant share of these: **today, the industrial sector is the second largest emitter of greenhouse gases in France, and it accounts for about one fifth of territorial emissions.**

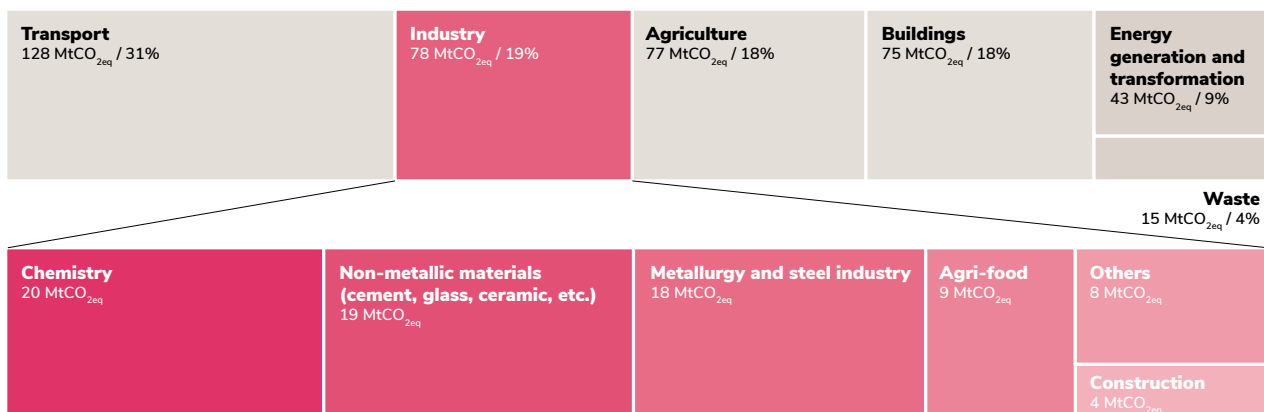
Industrial emissions are mainly related to the activity of a few sectors, which are also major energy consumers. In particular, the chemicals, minerals and metallurgy sectors each account for about 5% of French territorial emissions: their decarbonisation is an important issue for France. As part of the "France 2030" plan, roadmaps have been developed for each sector, detailing all the measures envisaged by manufacturers to reduce their emissions.

Figure 6.12: Final energy consumption of industry in France in 2021, and the share of electricity in the sector's final consumption



Source: Ministry of Ecological Transition – SDES, France's energy balance in 2022.

Figure 6.13: Breakdown of industry emissions by sub-sector in France, 2021



Source: CITEPA, Secten report 2023.

The industrial complexes corresponding to these sectors are concentrated in a few areas located in Hauts-de-France, Normandy, the Rhône Valley and Bouches-du-Rhône. In this regard, emissions are primarily concentrated on about fifty industrial sites, which alone produce 55% of the emissions of the entire industry. As part of its ecological planning, the government has set up “ecological transition contracts”¹⁴⁹ with the 50 industrial sites with the highest emissions, in order to monitor their decarbonisation commitments.

The decarbonisation of industry presents an additional challenge: that of ensuring that the growth in industrial energy consumption that will result

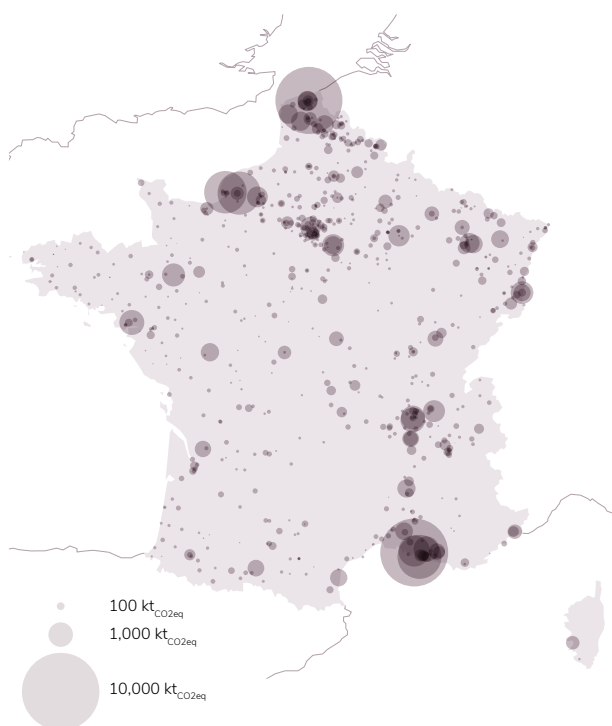
from the establishment on the territory of future industrial sites as part of the reindustrialisation of the country envisaged by the public authorities¹⁵⁰ is met by low-carbon energy. This ambition is supported, among other things, at the national level, by the Green Industry Act¹⁵¹ and, at the European Union level, by the Net-Zero Industry Act¹⁵², as well as by financing plans: France Recovery (in response to the Covid pandemic) and France 2030, with a budget of 35 and 54 billion euros respectively. The aim of these regulatory and legislative tools is both to relocate part of industrial production and to develop new activities, of which battery production and low-carbon hydrogen are two examples.

6.3.1 The electrification of industry and the reindustrialisation of the country will mark a clear break from the trend of the last 30 years

The period between 1970 and 1990 was characterised, in France, by an increase in the share of electricity in the final energy consumption of the industrial sector. This increase is not comparable to electrification in the sense that we understand it today in the context of the energy transition, that is to say a transfer of uses from fossil fuels to electricity. This is above all a consequence of changes in the composition of the French industrial fabric, including the relocation abroad of certain highly energy-intensive and polluting products and the consequent increase in the relative weight of industries where the share of electricity in consumption was higher.

Subsequently, between the 1990s and 2005, the share of electricity in final energy consumption in industry first increased slightly, then remained relatively stable, before a further increase in 2022. The relative stagnation since the 2000s is the result of several opposing effects: on the one hand, a slight increase in electrification, and on the other, a continuing change in the structure of the French industrial fabric.

Figure 6.14: Location of greenhouse gas-emitting industries on French territory



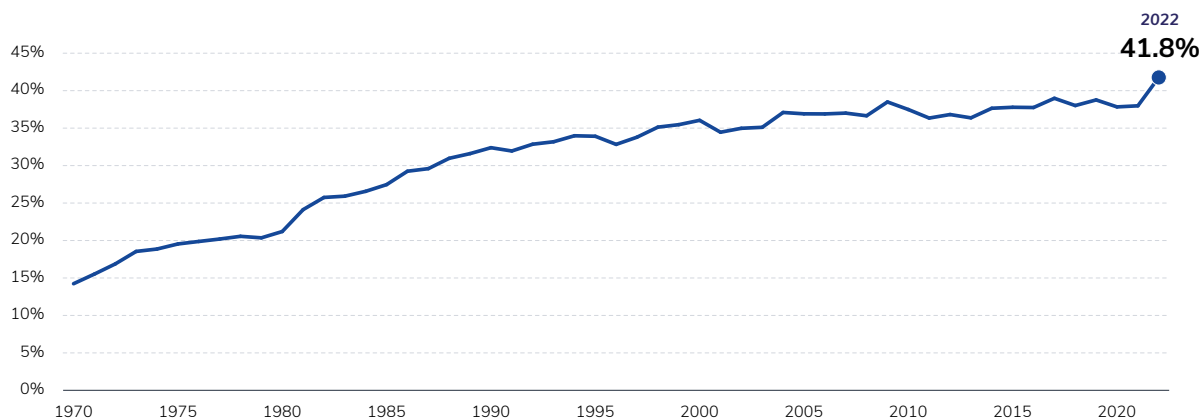
¹⁴⁹. enterprises.gouv.fr, Ecological transition contracts for the 50 most emitting industrial sites, 2023.

¹⁵⁰. French government, Accelerating the reindustrialisation of France, 2023.

¹⁵¹. French Ministry of the Economy, What does the Green Industry Act contain?, 2023.

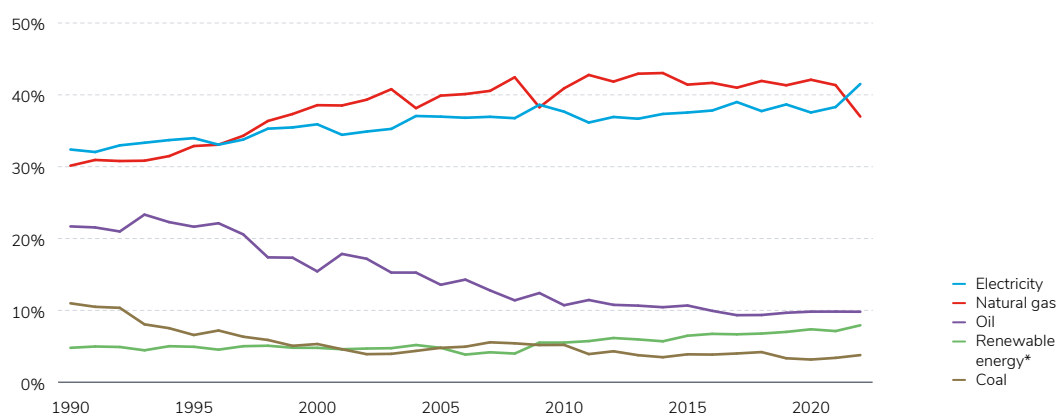
¹⁵². European Commission, The Net-Zero Industry Act: Accelerating the transition to climate neutrality, 2023.

Figure 6.15: Share of electricity in final energy consumption by industry (excluding heat sold, excluding use as raw material), between 1970 and 2022



Sources: Ministry of Ecological Transition – SDES, France 2022 energy balance; calculations: RTE

Figure 6.16: Change in the share of different energies in the final energy consumption of industry, excluding heat, between 1990 and 2022



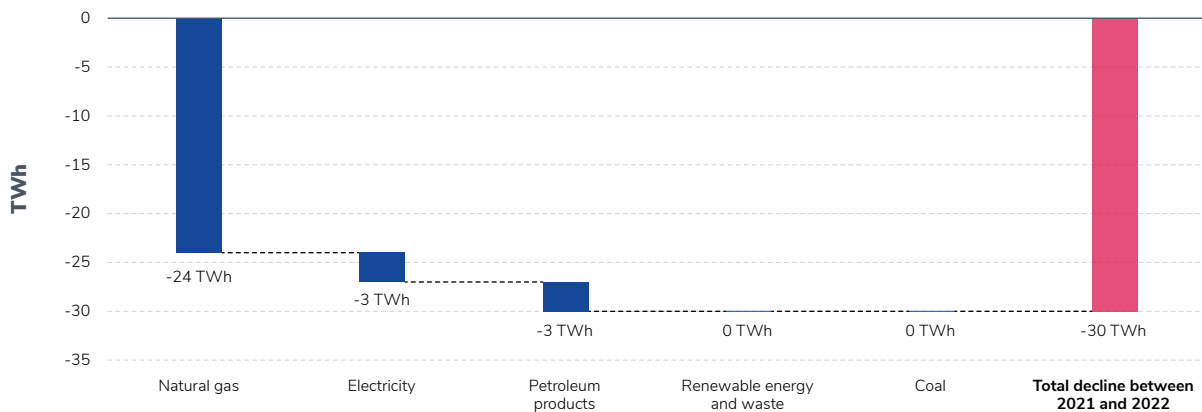
Source: Ministry of Ecological Transition – SDES, France's energy balance 2022; calculations: RTE

The share of electricity in the industry's final energy consumption reached its highest level ever in 2022. For the first time since 2009, when it narrowly edged out gas, it has once again become the energy most consumed by French industry, ahead of gas and well ahead of oil, renewable energies, waste and coal. This first place is the result of the greater contraction in natural gas consumption in the industrial sector, compared to that of electricity,

between 2021 and 2022. Indeed, in 2022, gas prices experienced an even more significant increase than electricity prices.

In the medium term, where possible and relevant, processes using fossil fuels should be replaced by processes using electricity with the aim of reducing emissions from industry. For example, ArcelorMittal has announced that it wants to replace the blast

Figure 6.17: Breakdown of the decline in final energy consumption of industry between 2021 and 2022 by type of energy



Source: Ministry of Ecological Transition – SDES, France's energy balance 2022; calculations: RTE

furnaces of its steel plants in Dunkirk and Fos-Sur-Mer, which run on coal, with electric furnaces¹⁵³. It should be stressed that, unlike the building and transport sectors, where the challenge lies in the scaling-up and mass adoption of technologies already in use, the electrification of industry presents technical and economic challenges specific to each process, and even to each site.

With its electricity mix already largely decarbonised, France currently has a comparative advantage (economic and climatic) in terms of electricity generation, which represents a window of opportunity for investment in industrial facilities over the next few years. To this end, direct electrification of industrial processes that can be electrified may lead to a direct decrease in emissions from some of these industries. For certain processes that cannot be electrified, the use of low-carbon hydrogen produced by electrolysis is the preferred option, which will still result in an increase in electricity consumption (this is indirect electrification), with issues concerning the flexibility of their consumption (see the *Flexibilities* chapter).

6.3.2 The indirect electrification of industry will rely on low-carbon hydrogen, a vector whose scaling-up presents significant challenges

The production of low-carbon hydrogen is essential to allow the decarbonisation of industrial sectors where complete electrification is impossible or irrelevant¹⁵⁴, which should lead to a considerable increase in demand for this energy vector. Hydrogen is currently produced mainly by steam-methane reforming, which emits greenhouse gases into the atmosphere. The use of alternative processes, such as the electrolysis of water from low-carbon electricity, is therefore necessary to achieve the decarbonisation objectives.

However, the ability of France and Europe to develop the production of low-carbon hydrogen on a large scale, at the necessary pace, is the subject of considerable uncertainty, both from an economic point of view and in terms of industrial strategy, particularly when it comes to ensuring the economic competitiveness of this activity in relation to other sources of supply (other more carbon-intensive processes, imports and natural deposits).

153. ArcelorMittal, 1.7 billion in investment to accelerate decarbonisation, 2022

154. Mainly for technical reasons: some industrial processes, for example, require very high temperatures, which cannot be achieved using electricity-powered systems. This is the case with ammonia production, for example.



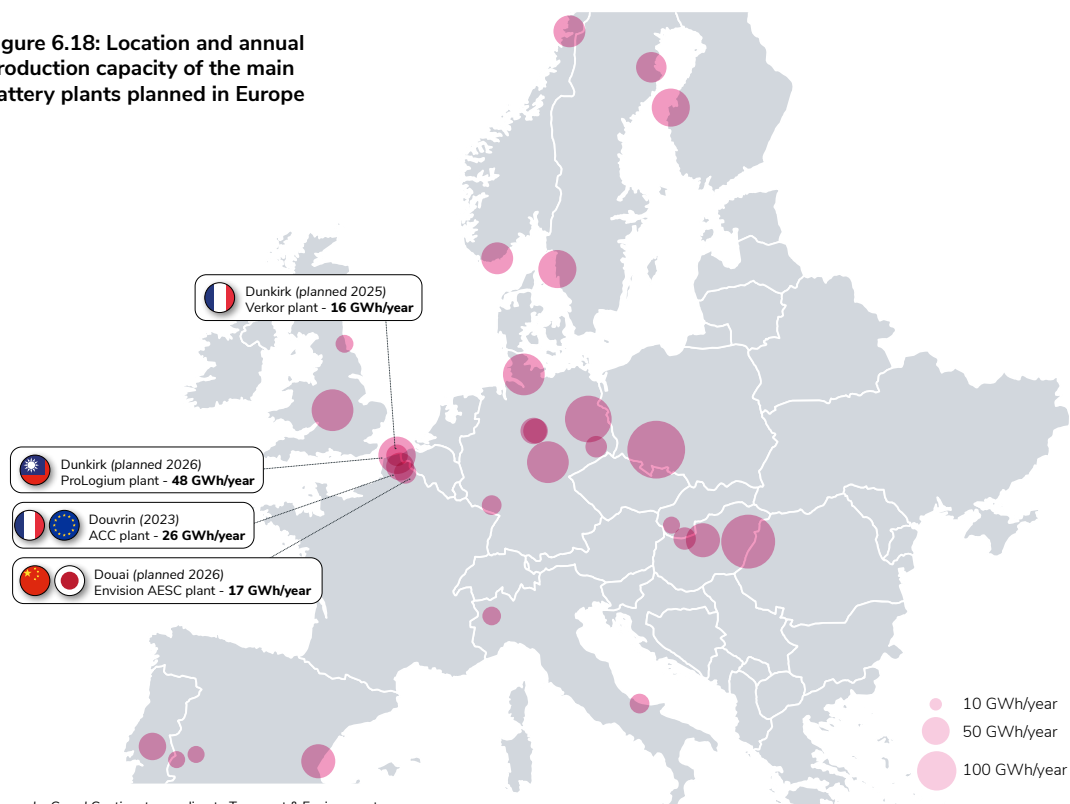
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Battery factories, an embodiment of the French and European ambition for reindustrialisation

The France 2030 plan includes a national “Batteries” strategy, the aim of which is to support the development of a French battery production activity. According to this trajectory, France should have a production capacity of 120 GWh/year of batteries by this deadline. The currently existing projects, all located in Hauts-de-France, already represent, in the long term, a total capacity of 107 GWh/year. The first batteries produced in France should leave the factory in 2024.

Supporting this activity will help to develop electric mobility and support the transport industry, since battery production is an essential component, accounting for a significant proportion of the added value in the production of a vehicle. Traditional automotive players are also involved in these projects, sometimes directly, as in the case of the ACC factory (Automotive Cell Company, a joint venture of Stellantis, Saft and Mercedes), and sometimes indirectly, as in the case of the Envision AESC factory, a Sino-Japanese company that will supply Renault’s plants.

Figure 6.18: Location and annual production capacity of the main battery plants planned in Europe



In order to structure this activity, as part of the French hydrogen strategy published in 2020¹⁵⁵, the government announced a target of installing electrolyzers for a capacity of 6.5 GW by 2030. For this, an envelope of €9 billion is planned to support investments in the activity over the period 2020-2030. Today, according to the initial guidelines submitted for consultation in November 2023 as part of the preparation of the next French Strategy for Energy and Climate, 300 MW have already been supported since 2020, and 2.5 GW of additional capacity should be commissioned in the years to come.

The production of hydrogen is also a major challenge for the power system. According to the estimates developed by RTE in the “*Bilan prévisionnel 2023*” (Generation Adequacy Report), electricity consumption of electrolyzers for hydrogen production in France could reach 65 TWh in the reference scenario¹⁵⁶. More generally, the electrification of the industry will also require electricity transmission infrastructures to be adapted so that they can support the growth in consumption by industrial sites, and this at a very high rate¹⁵⁷.

¹⁵⁵. French government, *National strategy for the development of decarbonised hydrogen in France*, 2020

¹⁵⁶. In the “A-reference” scenario. See RTE, *2023-2035 Generation Adequacy Report – Chapter 4 “The Scenarios”*

¹⁵⁷. *Vie publique*, Law of 23 October 2023 on green industry, 2023

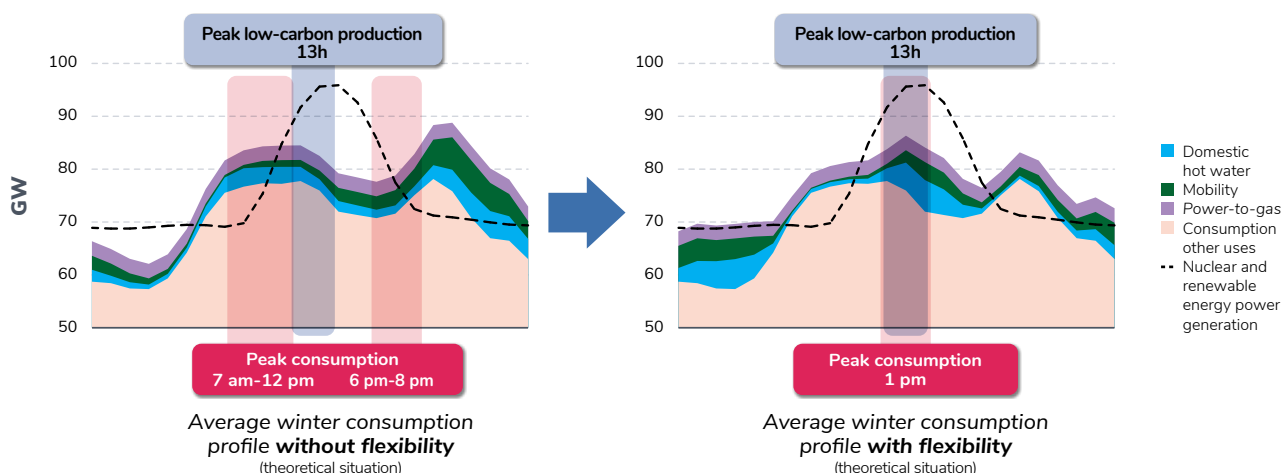
7. An increase in flexibility requirements driven by the development of renewable energies

In a power system where most production facilities can be controlled, as has long been the case in France and Europe, maintaining the balance between electricity supply and demand at all times is ensured by adapting the demand on the various production facilities to variations in consumption. Thus, in the sizing of the French generation mix, nuclear power generation has generally met basic requirements¹⁵⁸, supplemented by semi-base or advanced means (generally of the fossil thermal type) to cover increases in consumption over more or less long periods, especially during the winter. These resources, which are less inertial than nuclear power, also make it possible to deal with production or consumption contingencies in real time. Exchanges with neighbouring countries have completed the framework, making it possible to optimise the operation of the European system by taking advantage of the relative desynchronisation

of consumption peaks in the various countries¹⁵⁹. Adjustments to consumption or the use of storage facilities have also helped to ensure the balance between supply and demand, but to a lesser extent in relation to the flexibility of production.

This situation is gradually changing with the development of variable and non-controllable renewable production, wind and solar power in particular, which depends on weather conditions. In this context, the balance between supply and demand will increasingly require the adaptation of consumption to the variability of production, as well as the development of storage solutions (batteries for the very short term, power-to-gas for inter-seasonal storage, etc.). The controllable production must then cover the difference between the level of consumption and that of the non-controllable production¹⁶⁰ at all times (*residual consumption*).

Figure 7.1: (Prospective) illustration of the effect of flexibilities on the positioning of consumption during peaks in low-carbon production



¹⁵⁸. Even if, given its large share in the mix, French nuclear power has always modulated its production to a certain extent in order to adapt to variations in consumption. In other countries, nuclear power generation has historically been characterised by a virtually constant "baseload" operation over time.

¹⁵⁹. For example, consumption peaks are often reached in summer in Italy, due to air conditioning, and in winter in France, due to electric heating.

¹⁶⁰. Wind, solar and run-of-river hydropower generation.

Flexibility of consumption is therefore a key issue in the management of a power system with a high proportion of renewable energies. It enables the optimisation of the system's operation by positioning consumption when low-carbon production (renewable and nuclear) is abundant, which makes it possible to cover this with low-cost, low-carbon production, and to reduce consumption when recourse to fossil-fuel thermal production units, which are more costly and polluting, would be necessary.

The development of new uses for electricity, with the electrification of consumption that is currently largely covered by fossil fuels (mobility, industrial processes, heating), presents a significant

challenge in terms of system flexibility. These are large volumes of additional consumption, but they will be at least partly controllable. Electric mobility, the production of hydrogen by electrolysis and electric heating in buildings make it possible to adapt the consumption profile at least in part to low-carbon production, thanks to the possibility of storage: in the batteries of electric vehicles, which means that recharging can be postponed to a certain extent, of the hydrogen produced, which can be stored in suitable infrastructures, or even thanks to the thermal inertia of buildings, which means that heat can be stored. These new uses thus represent an opportunity to make the consumption profile more flexible, thereby optimising the operation of the system.

7.1 Different requirements and flexibility solutions

Wind and solar power generation are characterised by major seasonal trends: winds are generally stronger in the autumn and winter than in the summer, while spring and summer enjoy better sunshine thanks to longer days. On the other hand, the daily solar power generation profile is known and depends on the day/night cycle, but the actual production during a day may vary depending on weather conditions. The same applies to wind power generation, which does not have a characteristic profile over one day and depends on specific wind conditions. As a result, it is difficult to predict production in these generation mixes a long time in advance: the quality of forecasts improves as they get closer to real time, being much better one or two days before the day in question than one or two weeks before.

Consequently, the development of these non-controllable sources of production is leading to an increase in the system's flexibility requirements, which will change significantly in the medium and long term¹⁶¹. These requirements correspond to the controllable power supplies that must be mobilised to ensure the balance between electricity supply and demand at all times. They therefore contain two dimensions: that of instantaneous power, and that of the duration over which it must be mobilised (a few minutes, a few hours, a few days or longer horizons), which corresponds to the displacement over time of a certain volume of energy consumed or produced.

By analysing the variation in residual consumption over time, we can identify different types of flexibility requirements according to the following time horizons:

- **intra-day:** variations between times of the same day. In particular, photovoltaic production induces large variations in residual consumption between day and night;
- **intra-weekly:** variations between days of the same week. In particular, total consumption, and therefore residual consumption, varies greatly between working days and weekends;

in addition, wind power generation can vary, sometimes abruptly, between one day and the next;

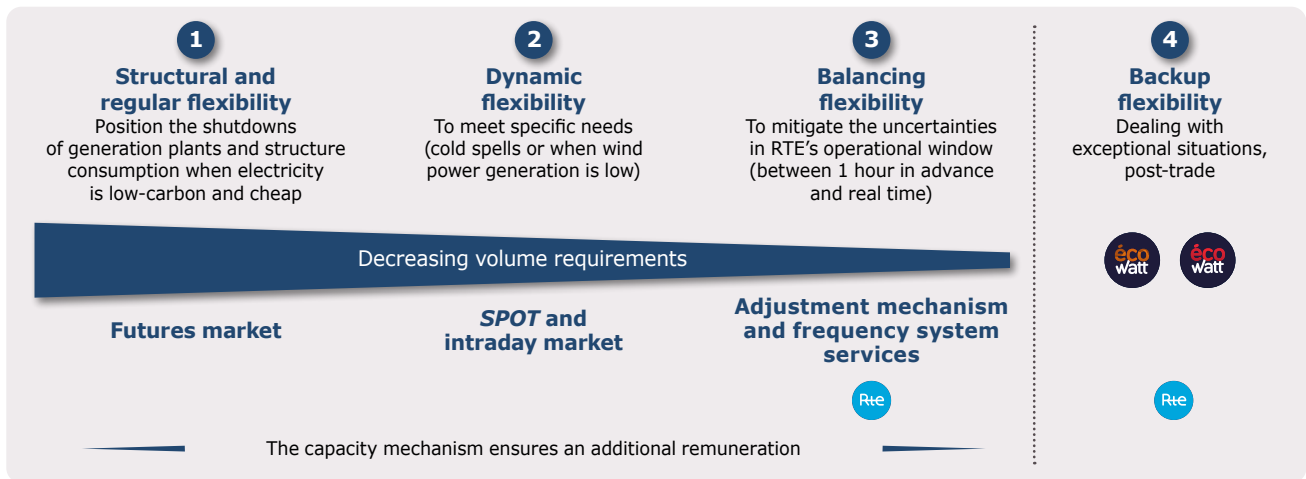
- **inter-weekly:** variations between weeks of the same season (summer or winter) which are mainly the result of climatic variations (temperatures, wind);
- **inter-seasonal:** variations between summer and winter;
- **inter-annual:** variations between one year and the next, which depend in particular on weather conditions (temperature level compared to normal, level of wind power generation, etc.)

Different types of flexibility make it possible to address these varied requirements. It is possible to classify them sequentially over time, with the volume of energy displaced decreasing as real time approaches:

1. **Structural and regular flexibilities:** these account for the bulk of flexibility requirements and are largely predictable (natural shape of the load curve, solar power generation during the day, etc.). The challenge lies in the positioning of consumption when low-carbon electricity is available. This involves modifying the load curves over time;
2. **Dynamic flexibilities:** they address requirements that can be predicted from a few days in advance up to intra-day, notably in response to uncertainties linked to wind power generation and the thermosensitivity of consumption;
3. **Balancing flexibilities:** they are used to compensate for unforeseen events (breakdowns, incidents) or uncertainties (linked to the weather in particular) associated with managing the balance between supply and demand in real time; their total requirement represents no more than a few GW, and will only increase marginally despite changes in the generation mix;
4. **Safeguarding flexibilities:** they concern the requirements needed to deal with exceptional situations affecting the supply-demand balance. The mobilisation of this type of flexibility is currently mainly based on the days and hours most at risk reported by the ecoWatt system.

¹⁶¹. RTE, 2023-2035 Generation Adequacy Report, 2023

Figure 7.2: Different types of flexibility, according to requirement and timeframe



The first three types of flexibilities are used every day and can be valued within the context of wholesale and balancing markets, while

safeguarding flexibilities meet exceptional, one-off requirements.

7.2 The residual load curve, a key indicator for the effective development of demand-side flexibilities

Residual consumption is defined on the basis of total electricity consumption minus the production of non-controllable renewable energies (with a variable production cost of zero): run-of-river hydro, solar and wind power. From the point of view of managing the balance between electricity supply and demand, residual consumption therefore represents the consumption that still needs to be met by other controllable production resources, with higher variable production costs.

Historically, before the significant development of variable renewable energies over the last few decades, this residual consumption was fairly close to total consumption, with non-controllable production corresponding essentially to run-of-river dams. These are small hydroelectric dams that exploit the flow of rivers, unlike hydropower plants that have a water stock and whose production is planned.

The gap between total consumption and residual consumption has widened under the effect of the

development of renewable energies, rising from 12% on average in 2014 to 24% in 2023. This gap varies with the seasons due to solar and wind power generation cycles.

7.2.1 Solar power generation causes a very regular distortion of the residual consumption profile, the magnitude of which is directly linked to the installed capacity

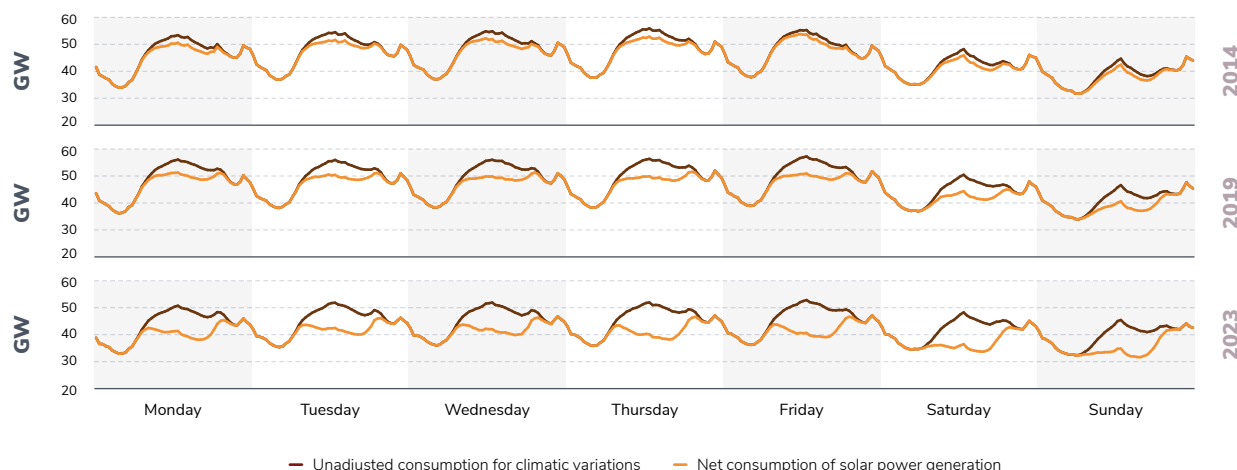
Naturally, the solar power generation curve over the course of a day is characterised by a bell-shaped profile centred, in France, on the early afternoon hours. As this production is directly dependent on sunshine, which is cyclical in nature, the shape of the solar power generation curve during a given period in a given year will closely resemble that observed during the same period in another year, provided that the cloud cover conditions are similar.

Figure 7.4 shows the effect of solar power generation on the distortion of residual consumption, for three years in the last decade, during the same week of July. It illustrates, on the one hand, the regular nature of the distortion caused by this source of electricity generation over the years and, on the other, the increase in the amplitude of the distortion, which follows the growth in the

Figure 7.3: Total consumption (unadjusted for climatic variations) and residual consumption during the years 2014 and 2023



Figure 7.4: Effect of the development of solar power generation on the distortion of the residual consumption curve, for a week in early July



installed base of photovoltaic solar power generation in France.

The regular nature of this production makes the use of demand-side flexibility highly relevant, particularly with regard to a structural and lasting distortion of the consumption curve thanks to the positioning of part of the consumption in the early afternoon hours. This type of flexibility can be accessed via simple mechanisms that already exist and have been effective, such as off-peak periods, which can be adapted to the peak of low-carbon production.

7.2.2 Wind power generation causes a more variable distortion of the residual consumption profile over time, the magnitude of which depends on the installed capacity and wind conditions

The development of the wind power generation profile over the years is less regular than that of the solar power generation profile: in fact, the wind power load factor, i.e., the output at any given moment in relation to the installed capacity, can vary more significantly from one year to the next on average than the solar power load factor. In addition, wind power generation is not characterised

by a daily cyclicity similar to that of solar power generation. However, even if wind power regimes are variable, they still show significant seasonal cyclicity: in fact, wind power generation is generally higher in winter than in summer, in line with the cycle observed for electricity consumption in France.

Figure 7.5 illustrates the effect of wind power generation on the distortion of residual consumption, for three years in the last decade, during the same week of March. In 2014, wind power generation was very low during the chosen week, due to a low load factor. The installed capacity was around 9 GW at the time. In 2019, on the other hand, the effect of wind power generation on the week under consideration is much more visible, reaching almost 10 GW on average, for an installed capacity of just over 15 GW. During the same week in 2023, wind power generation was fairly variable: relatively low at the beginning and end of the week, but very high in the middle of the week, when it exceeded 15 GW (for an installed capacity of around 21.5 GW).

Due to the variability of the wind load factor, the effect on the residual load curve of the increase in

Figure 7.5: Effect of the development of wind power generation on the distortion of the residual consumption curve, for a week in mid-March

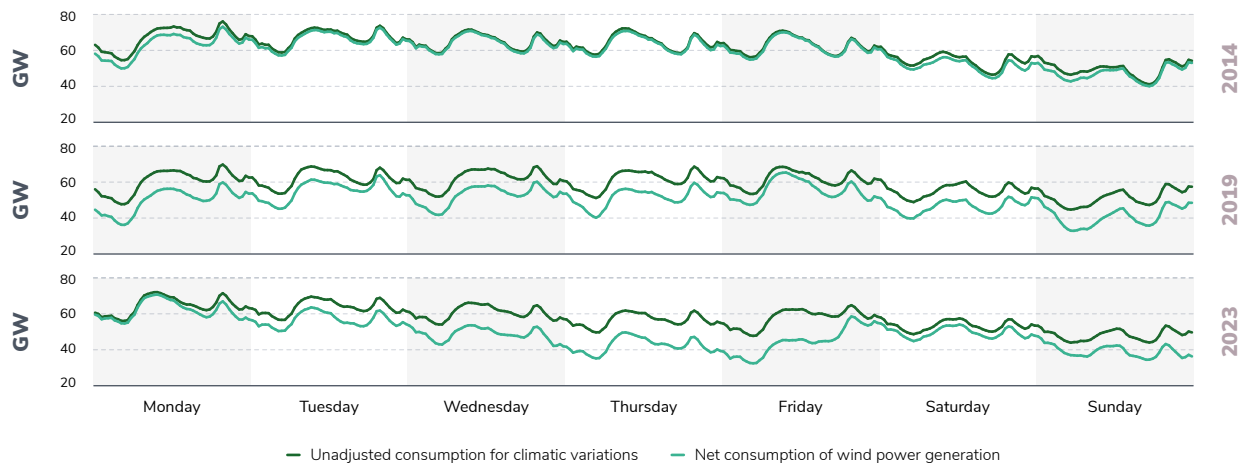
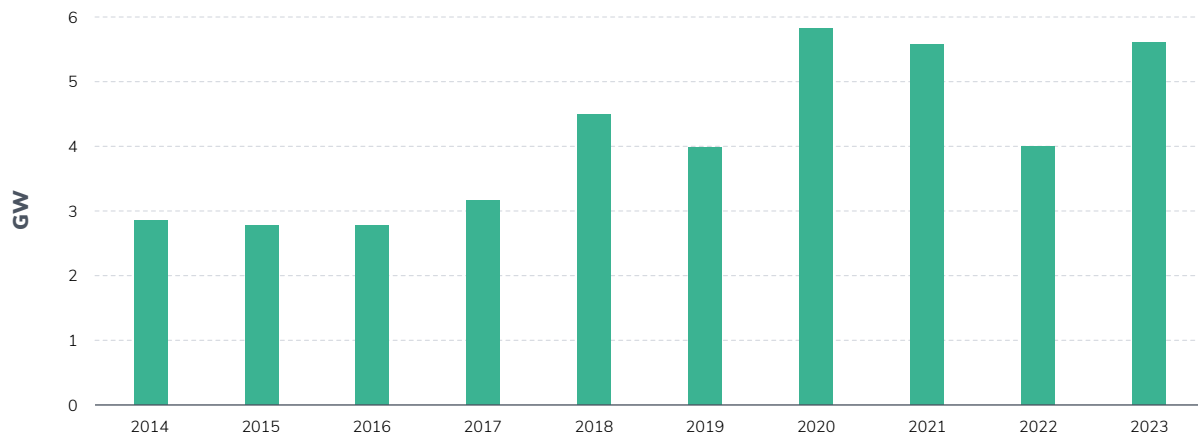


Figure 7.6: Average wind power generation when the level of consumption is in the top 10%



installed capacity is not as linear as for solar power capacity. However, residual consumption tends to change as wind power capacity increases, and its effects will become increasingly visible.

Given the nature of wind power generation, the flexibilities that can be called upon to match generation and consumption profiles are dynamic flexibilities, which can be mobilised from a few days before real time to one hour before, and balancing flexibilities, which can be mobilised as close to real time as possible.

As a result, wind power generation forecasts are of considerable importance for the operation of the power system, particularly in terms of generating the right signals for flexibility resources. Over a given timeframe, wind power generation forecasts for aggregated territorial grids are more accurate than those for a single wind farm, since the latter may be affected by very local phenomena, which are by their very nature more random and difficult to anticipate. With the right statistical tools in place, wind power generation forecasting is becoming an increasingly important factor in the operation of the power system.

Although their contribution varies over the year, renewable energies are now making a significant contribution to security of supply. By way of illustration, wind power generation averaged 5.6 GW during the hours when consumption levels were

in the top 10% of the year. Due to the favourable conditions, this contribution was even 8.2 GW at the annual peak of 84.2 GW recorded on Monday 23 January at 7 p.m., i.e. almost 10% of consumption was covered at that time.

7.3 Flexible demand is a lever that is already in use today

Demand-side flexibilities are already a valuable lever for balancing the power system, even if their importance is set to increase in the years to come. During the 1980s, a significant transformation of the French electricity mix was brought about by the rapid deployment of nuclear power and electric heating. This transformation has led to the emergence and subsequent spread of two major categories of demand-side flexibility, driven by pricing signals.

Firstly, regular, daily structural flexibility, orchestrated by the “off-peak” signal, to which the domestic hot water tanks are largely directly linked. This has made it possible to limit consumption during daily peaks and to optimise the use of nuclear power available during the night.

Secondly, a dynamic flexibility supported by tariff offers for load shedding linked to supply, such as “peak day load shedding (in French, “effacement des jours de pointe”, EJP)” and then “Tempo”, which were introduced to encourage consumers to reduce their consumption on the most challenging days from the point of view of the balance between electricity supply and demand, particularly on the coldest days. Due to the tension on the supply-demand balance during 2022 and the winter of 2022-2023, consumers were encouraged to choose these tariff offers: the number of customers subscribing to this offer is estimated to have risen from 200,000 to 500,000¹⁶² between October 2022 and October 2023.

Since 2010, new forms of explicit load shedding have emerged through aggregators independent of electricity suppliers, representing around 3 GW of activatable power, mainly in the industrial sector and marginally in the tertiary sector. In the residential sector, players specialising in explicit load shedding have also emerged, with a total capacity of around one hundred megawatts on the market, with prospects for growth over the next few years. In the building sector, the redundancies are mainly from the EJP and Tempo tariffs (valued by the electricity supplier via dedicated tariff offers) and currently amount to 900 MW.

This load shedding can be mobilised on the wholesale electricity markets through the NEBEF mechanism, or directly by RTE through the balancing mechanism, which ensures that the power system is balanced as close as possible to real time. In this respect, load shedding represented a volume of 8.5 GWh, down sharply on 2022, when 17.6 GWh were activated.

Finally, demand flexibility can, in the most difficult cases where security of supply is directly threatened, play the role of flexibility to safeguard the power system in the most tense situations. In particular, this is the aim of the ecoWatt system, which is designed to alert consumers to periods of tension in the power system, so that they voluntarily reduce their consumption during these periods in order to avoid targeted power cuts to which the consumers concerned are subjected. The ecoWatt system evolved in 2022, and now alerts consumers up to 3 days in advance of voltage situations on the power system.

162. Boursorama, EDF is satisfied with the success of its Tempo option and the energy savings it entails, 2023



FOCUS

The deployment of demand-side flexibilities must be based on a dedicated scaling plan, whose deployment and effect on the load curve must be monitored

RTE stressed in the “*Bilan prévisionnel 2023*” (Generation Adequacy Report) the need for a scaling-up plan for demand flexibility, to support the transformation of the electricity mix in the next decade. This plan is based on three pillars: an industrial programme for the deployment of equipment to give players the technical solutions they need to activate their flexibility levers, a strengthening of economic incentives to encourage these players to make their flexible sources available to the power

system, and monitoring of the effects of these flexible resources on residual consumption to ensure that these are activated at the most opportune times. Some key indicators, such as the number of commercial buildings equipped with building management systems, or the number of residential consumers benefiting from offers that promote flexibility of use, will make it possible to monitor the spread of these sources of flexibility.

7.4 Storage facilities

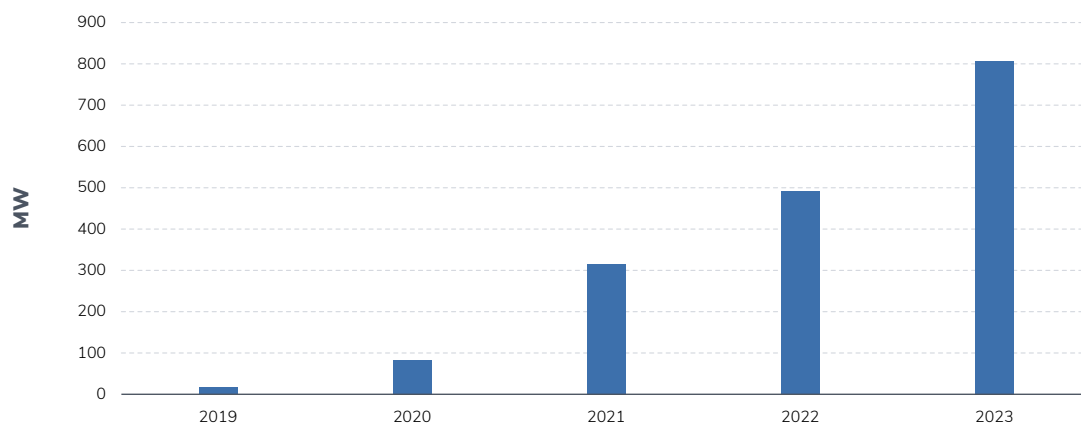
The storage facilities currently in use in France are mainly pumped-storage power plants (PSP) and, to a lesser extent, batteries.

The contribution of batteries and daily PSPs to the flexibility of the power system is concentrated on the intra-day scale, since these resources make it possible to absorb the surplus energy produced during the afternoon or night and release it when consumption peaks in the morning and evening. Because of the high costs associated with their storage capacity, batteries are designed to store a volume of energy that can be restored in just a few hours (less than four hours or even less than two hours, depending on the type of system). They can then store this energy and return it to the system a few hours or a few dozen hours later. This service is similar to demand-side flexibility (such

as controlling the recharging of electric vehicles or the positioning of domestic hot water production during hours of high photovoltaic production), and is particularly useful in scenarios of accelerated photovoltaic development in Europe. The benefits of deploying batteries are therefore largely dependent on the extent to which consumption flexibility is mobilised, and vice versa. The analyses in “Futurs énergétiques 2050” (Energy futures for 2050) highlighted the strong competition between these two types of solution, which is confirmed by the new studies in the “Bilan prévisionnel 2023-2035” (Generation Adequacy Report).

Thanks to their larger storage volumes, weekly PSPs can also be used to shift some of the energy produced over the weekend to weekdays. They can also help to smooth out variations in wind power generation over the course of a given week.

Figure 7.7: Total power of batteries installed in France, in injection, between 2019 and 2023

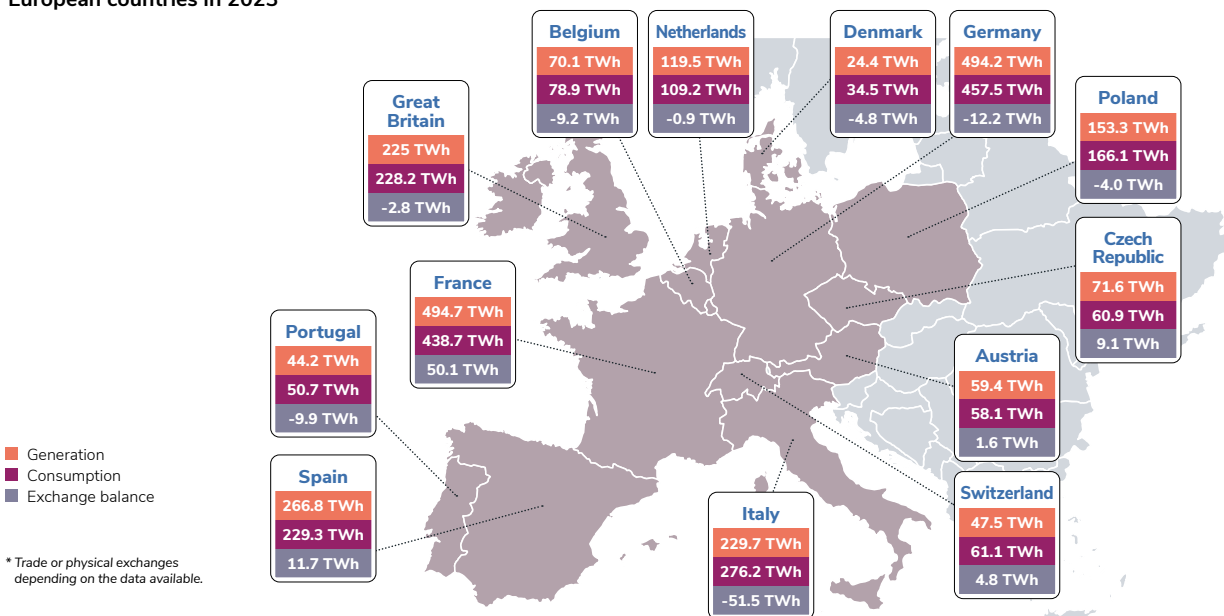


8. The decarbonization of the European power system progressed, thanks to the massive rollout of wind and solar, and the shutting of coal-fired generation

The energy crisis of 2022 was a European crisis, due in particular to the increase in gas prices, which was passed on to electricity prices in all countries, leading to a significant drop in consumption, the drop in hydropower generation that affected the southern countries, and the drop in low-carbon and economically competitive French exports. **In 2023, some of the trends that began in 2022 continued: as a result of high prices, above-normal winter temperatures and measures to reduce energy consumption by public**

authorities, businesses and private individuals, European¹⁶³ electricity consumption slowed once again, reaching levels unseen in the last decade. Production has followed this downward trend in most countries, with the notable exception of France, where the revival of nuclear power and hydropower generation, as well as the increase in renewable production, have made it possible to return to a level of production that is significantly higher than that forecast for 2022, and to significantly increase export volumes.

Figure 8.1: Map of unadjusted electricity consumption and production, and the balance of electricity exchanges* for several European countries in 2023



163. Scope: ENTSO-E countries (including Northern Ireland) and Great Britain. ENTSO-E is the European network of electricity transmission system operators (TSOs), bringing together 39 operators from 35 countries. The TSO of the United Kingdom, National Grid, is not part of ENTSO-E, unlike that of Northern Ireland, SONI. The list of member countries is available [here](#).

Most European countries have continued to develop their renewable energies at a sustained pace, in line with energy transition targets that have sometimes recently been revised upwards.

The share of wind and solar power in the generation mix continued to grow, breaking numerous records. Coal-fired production has declined significantly over the past decade as a result of plans to

close coal-fired power plants in several countries. The share of nuclear power generation in the mix is showing a slight downward trend, due to the shutdown of several reactors. The fall in production from these two sources was partly offset by the rise in production from renewable sources, particularly wind and solar power, and to a lesser extent by an increase in production from gas-fired units.

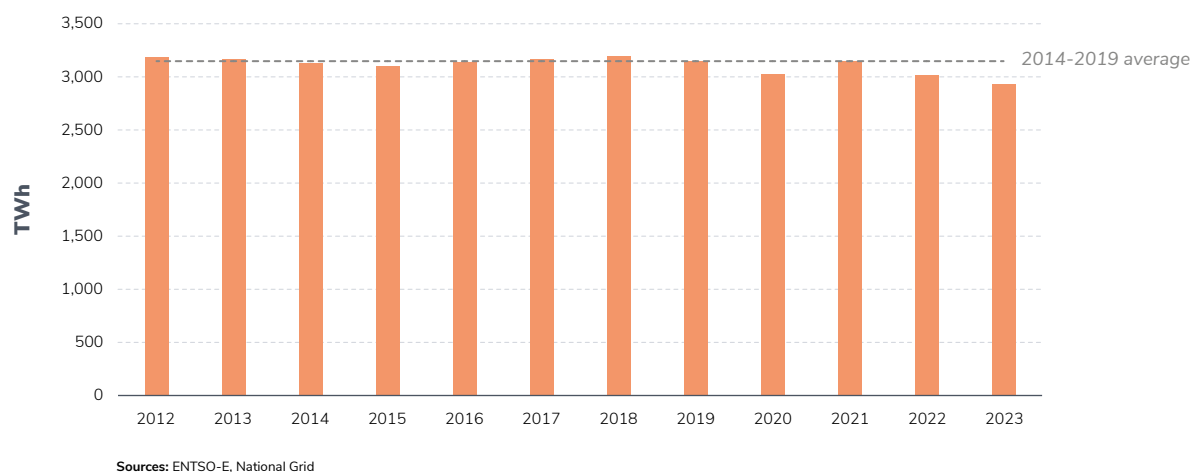
8.1 The decline in European consumption continued in 2023, continuing the trend observed in 2022

Electricity consumption¹⁶⁴ in Europe¹⁶⁵ has fallen for the second year running, and in 2023 will be well below the average consumption in the years preceding the health and energy crises (2014-2019). After 2020, a year heavily affected by the COVID-19 epidemic, followed by an upswing in consumption thanks to the economic recovery in 2021, 2022 saw a sharp fall in consumption, even below that of 2020. This reflected the rise in electricity prices and, more generally, commodity prices, which had affected economic activity, the action taken by several countries to save energy in the face of the crisis, and temperatures well above normal during the heating season. The year 2023 is part of this dynamic, with total consumption being 2.7% below that of 2022 and 6.9% below the average observed during the period 2014-2019. According to an estimate by the International Energy Agency,

nearly two-thirds of the drop in electricity consumption in the European Union between 2021 and 2023 is attributable to the industrial sector, due to rising prices¹⁶⁶.

The same trends can be found to a greater or lesser extent in each country, particularly among the most heavily populated countries, which are the main consumers of electricity in Europe. In Germany, the factors put forward to explain the decrease in consumption between 2022 and 2023 are first and foremost high prices and high temperatures, followed by the increase in self-consumption of households equipped with photovoltaic panels¹⁶⁷. In the UK, mild temperatures in summer and moderate temperatures in autumn have also led to a fall in demand for electricity for air-conditioning and heating, against the backdrop of a shrinking economy that is reducing the need for electricity. In Italy and Spain, the TSOs mention the fall in industrial consumption due to the rise in electricity prices as the main explanation for the fall in demand.

Figure 8.2: Unadjusted electricity consumption in Europe (scope: ENTSO-E and Great Britain)



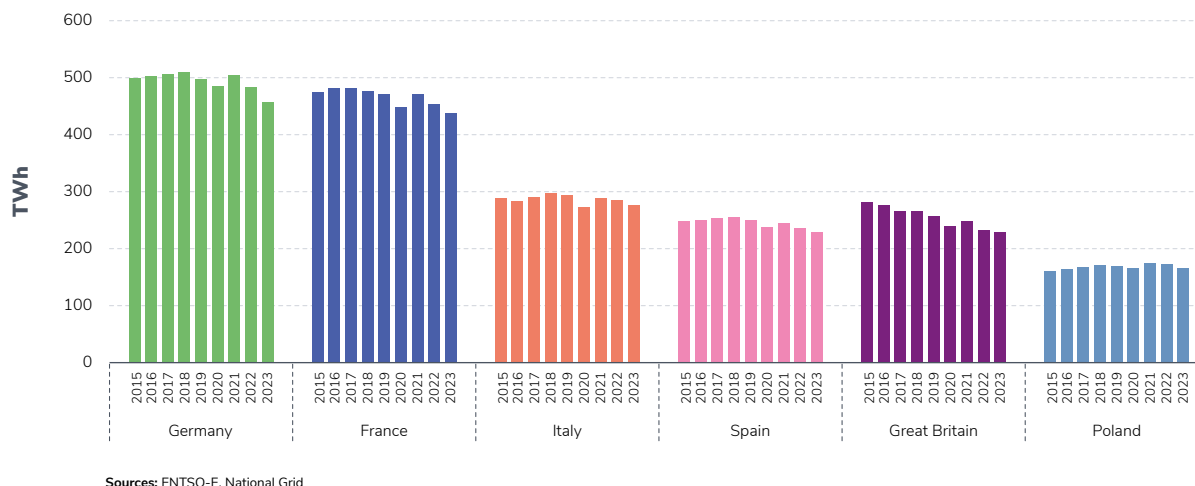
¹⁶⁴. This is consumption unadjusted for weather effects.

¹⁶⁵. Scope: ENTSO-E countries (including Northern Ireland) and Great Britain.

¹⁶⁶. International Energy Agency, *Electricity 2024 Executive summary*, January 2024 (in English).

¹⁶⁷. Fraunhofer Institute, *Public Net Electricity Generation 2023 in Germany*, Press Release, January 2024 (in English).

Figure 8.3: Unadjusted electricity consumption for the six main consumer countries in Europe



Comparing the absolute levels of electricity consumption in different countries provides only a partial picture, as there are so many factors that determine this: population, temperature, length of daylight, gross domestic product, electrification rate, rate of individual and collective housing, etc. The most populous countries are generally those that produce and consume the most electricity: the six most populous countries are those with the highest electricity consumption, i.e., Germany, France, Italy, Spain, Great Britain and Poland. However, the ranking is not strictly adhered to, since Great Britain, which has almost as many inhabitants as France, consumes far less than France, and more like Spain, which has 20 million fewer inhabitants. Similarly, behind Poland is Norway where, despite a population seven times smaller, consumption was only 32 TWh lower. With abundant hydropower capacity (33 GW installed) and low production costs, highly electro-intensive industries have developed strongly, as has the use of electric heating.

It is therefore interesting to look at the consumption of European countries relative to their population on the one hand, but also to their electrification

rate (share of electrical energy in end-use final consumption). Thus, per capita consumption in 2023 for all ENTSO-E members and Great Britain was 4,800 kWh/capita. In France, with 5,500 kWh/capita, per capita production was the highest among the main European countries (from the point of view of the number of inhabitants and electricity consumption and production), which should also be seen in the light of a higher electrification rate. Per capita consumption is largely influenced by the electrification rate, with the Nordic countries in the top three: Norway (21,700 kWh/capita), Finland (12,600 kWh/capita) and Sweden (11,000 kWh/capita), which are among the top four countries in terms of the electrification rate of energy consumption.

A country's electricity consumption is also sensitive to temperature. A drop in temperature below a certain threshold means greater use of heating, sometimes electric heating, and therefore a higher level of consumption. To a lesser extent, electricity consumption is also influenced by the length of the day, which determines lighting needs. While all countries have winter thermosensitivity¹⁶⁸, it is currently more pronounced in France than in

¹⁶⁸. It can be seen that below about 15°C, consumption increases as the temperature decreases.

Figure 8.4: Electricity consumption per capita according to the electrification rate for a selection of European countries in 2023

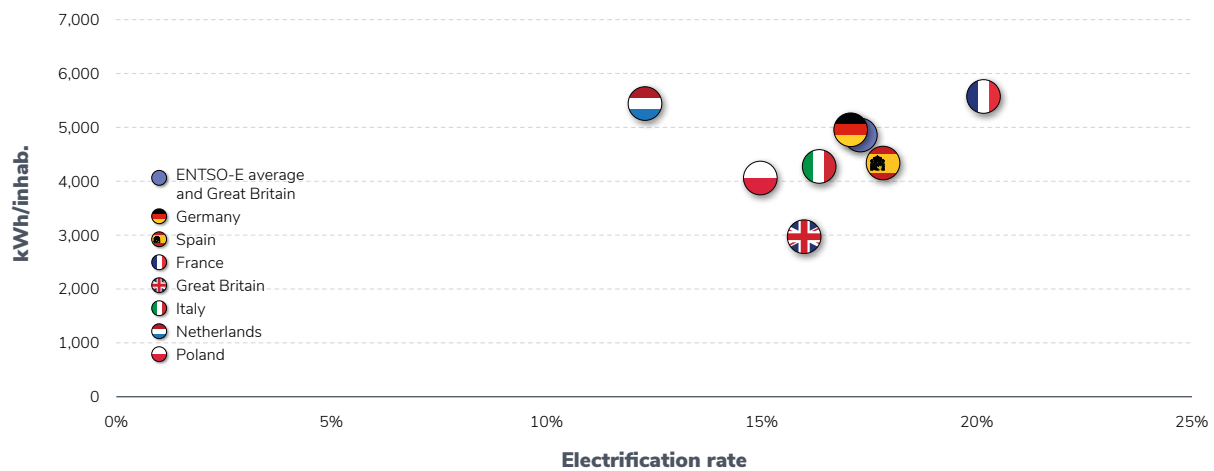
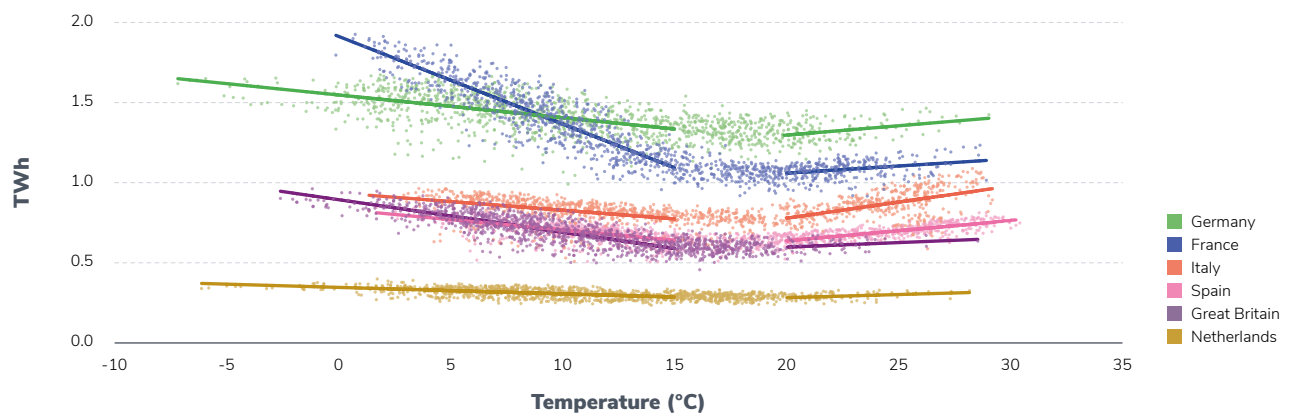


Figure 8.5: Daily consumption according to temperature for a selection of European countries between 2019 and 2023 (working days only)



other countries, including colder countries such as Germany, due to a more widespread use of electric heating. However, this is set to change over the next few years with the electrification of uses in Europe¹⁶⁹.

Conversely, the hotter days of summer can mean greater use of air conditioning. This last effect is

likely to become more pronounced, with the climate heating up with more frequent and more intense heatwave episodes. As a result, air conditioning is gradually becoming more widespread, even in northern countries. This summer thermosensitivity is visible from 20°C in the hottest countries in southern Europe, where the use of air conditioning is currently more systematic than in the North.

169. For example, the German TSOs expect electricity consumption to double by 2045 to reach 1,300 TWh. [German TSOs. Netzentwicklungsplan Strom 2037 mit Ausblick 2045, Version 2023, 2023 \(in German\)](#)

In the extreme, Italy shows a more pronounced thermosensitivity in summer than in winter.

Thermosensitivity is not very visible in the Netherlands, which may be due to the fact that the country's energy mix is heavily focused on gas, of

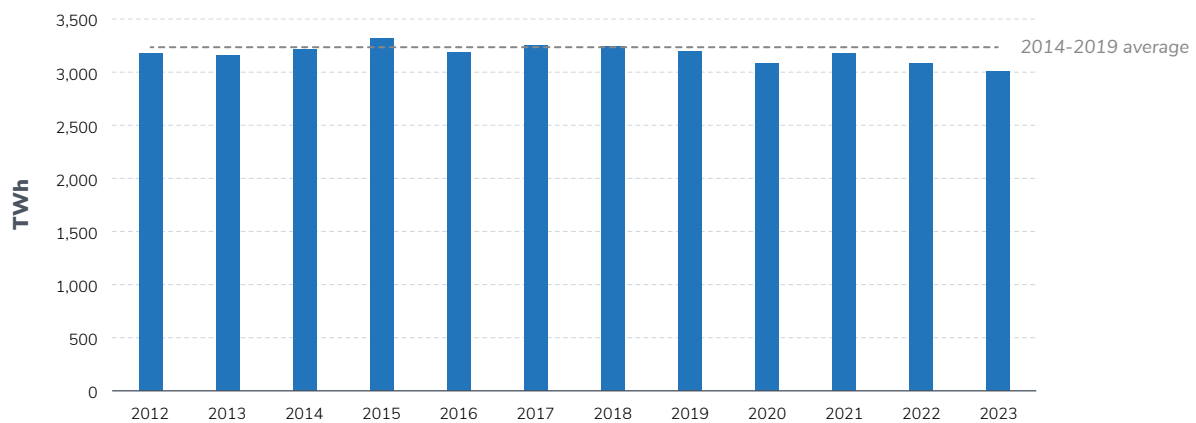
which it is a producer. The effect of electric heating is therefore less noticeable on cold days. The country is also less prone to the hotter days seen elsewhere, with air-conditioning consumption remaining insignificant for the time being.

8.2 Most European countries show a fall in production in line with the lowest level of consumption

Trends in production levels in Europe¹⁷⁰ reflect those observed for consumption. The decline in production already observed in 2022 compared

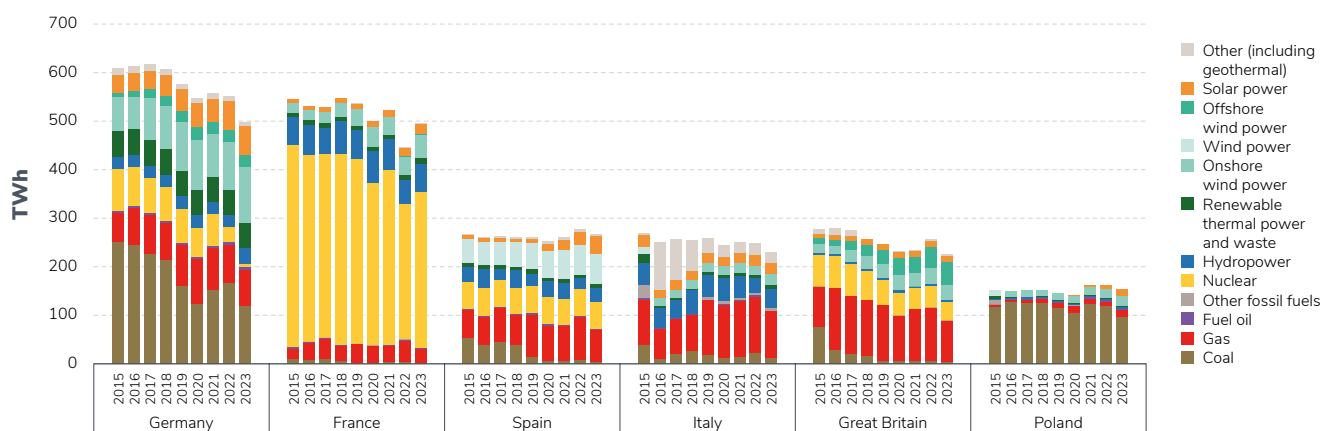
to 2021 (-2.9%) is confirmed in 2023 (-2.6% compared to the previous year). Among the largest countries, only France recorded a significantly higher generation volume than in 2022, due to an increase in generation from nuclear, hydropower and renewable sources, which had the effect of covering a greater proportion of national

Figure 8.6: Electricity generation in Europe between 2012 and 2023 (scope: ENTSO-E and Great Britain)



Sources: CBS (data for the Netherlands estimated for November and December 2023), Energy Charts, ENTSO-E, National Grid, REE

Figure 8.7: Electricity generation, by type, for the six main producer countries in Europe



Sources: ENTSO-E, National Grid, Energy Charts, REE

Some data sources aggregate the categories "onshore wind power" and "offshore wind power" under the name "wind power".

¹⁷⁰. Scope: ENTSO-E countries and Great Britain

consumption and returning to an export profile (see the *Production and Exchange* sections). For the other countries, the fall in consumption and, to a lesser extent, the increase in French exports led to a sharp fall in production: Germany (-10.3%), Great Britain (-12.1%), Italy (-9.3%). Other countries saw their production increase in 2023 compared to 2022, even though their consumption continued to decline. For example, Finnish production (74 TWh in 2023) increased by 16% whereas consumption was down by 0.3%. This increase of 10.4 TWh is mainly driven by the nuclear (+8.6 TWh), wind (+2.9 TWh) and hydropower (+2 TWh) generation mixes, which also offset the decline in other generation mixes such as fossil fuels (-3.2 TWh). The highlight of Finnish production in 2023 was the commercial commissioning in April of the Olkiluoto 3 EPR reactor, with a power of 1.6 GW, which produced 10.4 TWh in the year¹⁷¹.

At the European level, the most significant decrease in production between 2022 and 2023

concerned the fossil fuel thermal generation mix, whose production volume decreased by 21%. Production from coal-fired units alone accounted for about half of this decline. Another highlight of the year was the fact that in 2023, **for the first time, wind power generation outstripped gas-fired power generation, whereas ten years ago it accounted for half**. The decarbonisation of the European electricity generation mix continued in 2023, thanks to an increase in production from solar and wind power in all countries, in line with previous years, which helped to reduce the level of production from fossil-fuel thermal plants in particular. Nuclear power generation remained stable in 2023 compared with the previous year (+0.6%): the drop in output due to the closure of the last three reactors in Germany in 2023 (see focus below) and of two reactors in Belgium between the end of 2022 and the beginning of 2023¹⁷² was offset by the commissioning of the Olkiluoto 3 EPR in Finland and by the increase in output from the French fleet.

¹⁷¹. ENTSO-E data

¹⁷². The Tihange 2 reactor was shut down in February 2023, following the closure of the Doel 3 reactor in October 2022. These two reactors had a cumulative capacity of 2 GW (that is to say, nearly 7% of the total installed capacity). Nuclear power still accounted for 45% of the Belgian electricity mix in 2023, even though its share had fallen from 50% in 2022. The remaining five Belgian reactors were scheduled to close in 2025, but the government and the operator ENGIE Electrabel signed a final agreement in December 2023 to extend the operation of the two newest reactors, Doel 4 and Tihange 3, until 2035.

8.3 The European electricity mix is now mostly decarbonised

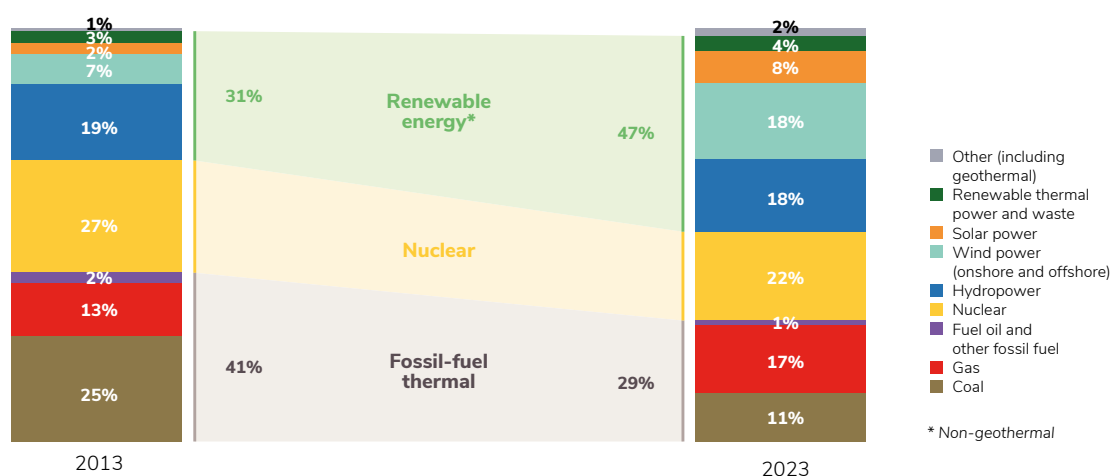
The European electricity mix has profoundly changed compared to the mix of only ten years ago. Solar power and wind power now play an important role, accounting for 26% of the generation mix in 2023 (scope: ENTSO-E and Great Britain), compared with 9% ten years earlier. Although fossil-fuel thermal production still accounted for 29% of electricity generation in the scope in 2023, its share of the European mix has fallen by eleven points in a decade (from 40% in 2013). When considering the different fuels separately, the trends differ. Indeed, gas production has seen its share of the mix increase over the decade (17% in 2023 compared to about 13% in 2013, after a peak at 20% in 2019-2020). In contrast, **the share of coal-fired production, characterised by a very high carbon intensity, has fallen drastically, from 25% to 11% in ten years**, and shows a structurally downward trend in all the countries considered. The most extreme example is Great Britain, where the share of coal in the national mix has fallen from 40% to 1% in ten years. **So, for the first time in 2023, Europe's top three production**

sources (nuclear, wind and hydropower) will be decarbonised.

While nuclear power has always been the main source of electricity generation over the past decade, it has fallen in absolute value, with more reactors having been shut down, due to their age or by political choice (see, for example, the focus on Germany), than commissioned. From a hydro-power point of view, production has remained relatively stable, mainly driven by the amount of annual rainfall. The installation of new structures is marginal, the suitable sites being, for the most part, already exploited.

If we break down the volumes produced by each production source in each country, it comes as no surprise to find that the sources with the greatest presence in the largest producer countries are in first place, reflecting the “size” of the electricity mix and the relative share of each source in it. Thus, the largest volume of production is achieved by French nuclear power (320 TWh, 65% of the French generation mix in 2023), followed by Norwegian hydropower (136 TWh, 89% of the mix) and German coal (118 TWh, 24% of the mix). French

Figure 8.8: Electricity generation in Europe, by generation mix, over the last ten years (scope: ENTSO-E + Great Britain)



nuclear power accounted for around 11% of electricity generation in the countries in the scope under consideration, an increase on the previous year when, despite historically low production

(279 TWh in 2022), it still accounted for around 9% of total production in the scope. Norwegian hydropower and German coal respectively reached second and third place in 2023 (4.6% and 3.9%).

Figure 8.9: Electricity generation in Europe by production source between 2012 and 2023 (scope: ENTSO-E and Great Britain)

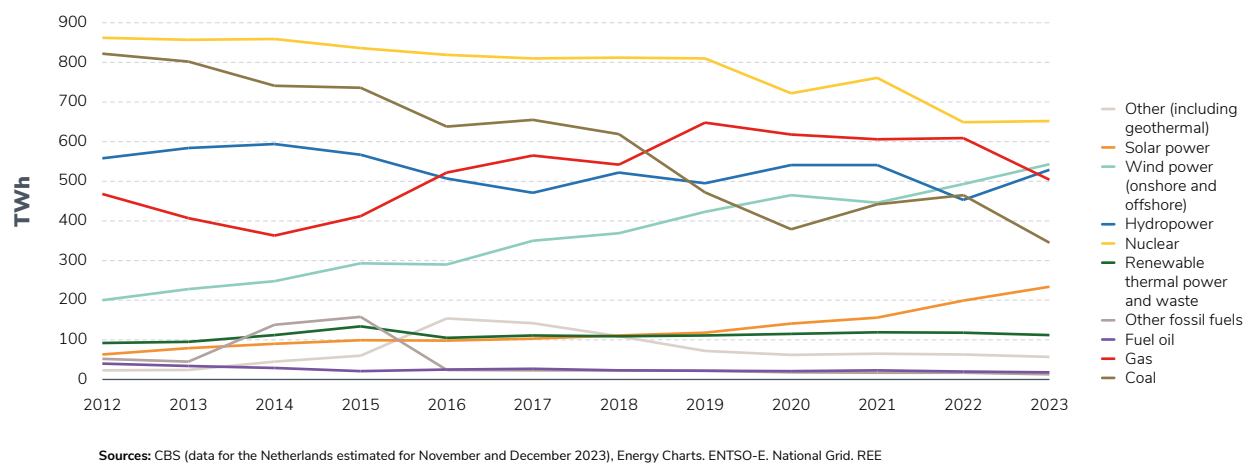
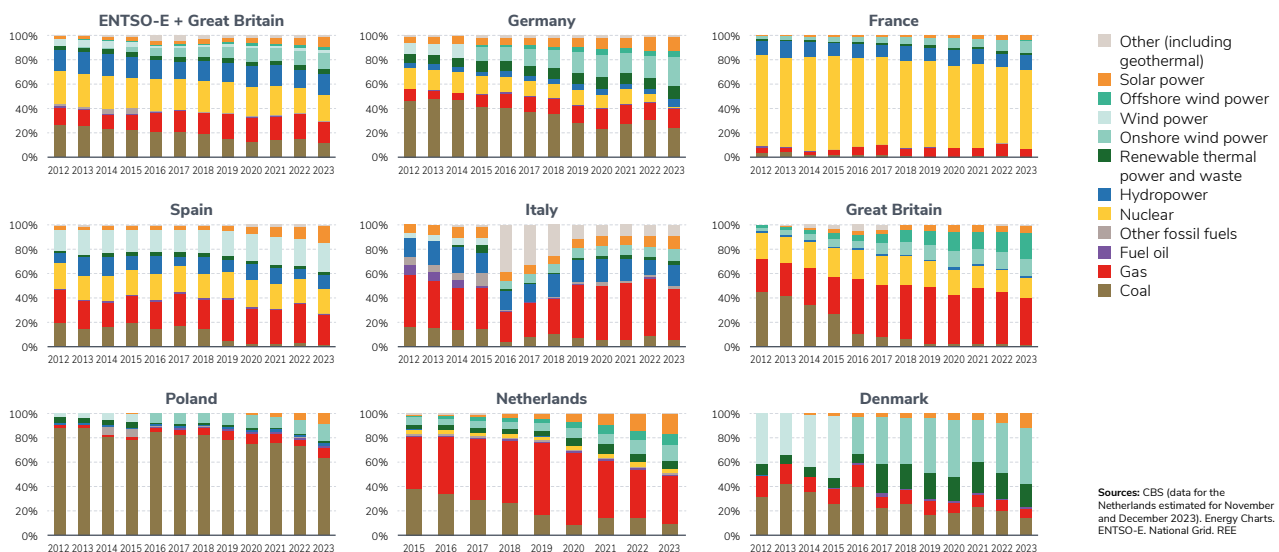


Figure 8.10: Electricity mixes in a selection of European countries and in the ENTSO-E and Great Britain aggregated scope, between 2012 and 2023

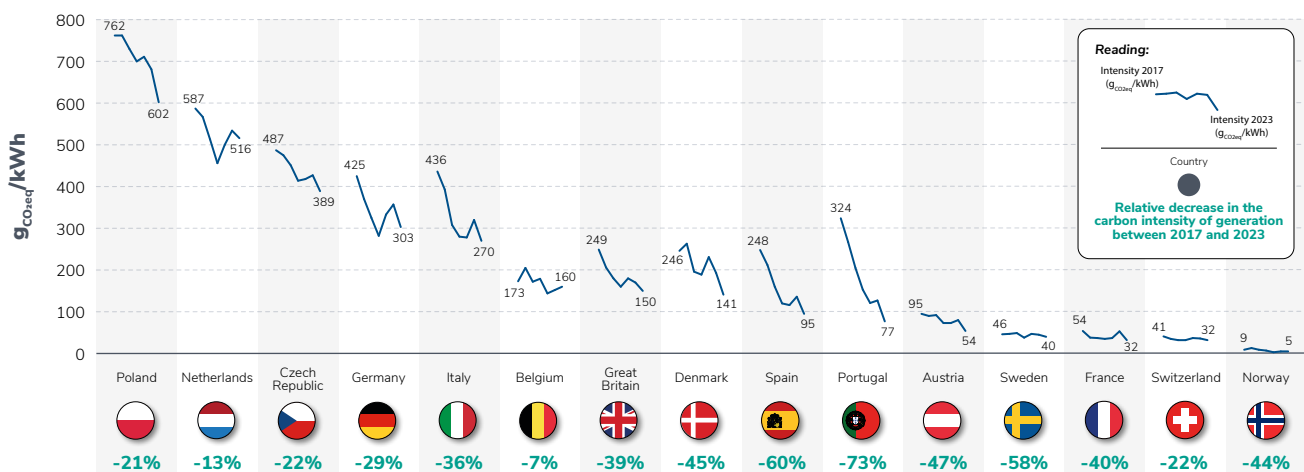


8.4 Overall, the carbon intensity of the electricity mixes of European countries has fallen significantly since 2017

In order to meet the commitments made under the Paris Agreement as well as the various binding laws that have been introduced at the national and European Union level, the European countries are all committed to the decarbonisation of their economies. The European Union's climate and energy policies began in 2008 with the “energy-climate package”, which aimed to reduce greenhouse gas emissions by 20% compared to 1990 levels by 2020 and to achieve a 20% share of renewable energy in final energy consumption, with the Renewable Energy Directive¹⁷³. These targets were raised to a 40% reduction in emissions compared with 1990 and a 32% share of renewable energy in final energy consumption by 2030 in 2014¹⁷⁴ and again in 2018¹⁷⁵.

These objectives were again modified as part of the Fit-for-55 legislative package presented in 2021, which sets a target of reducing the European Union's greenhouse gas emissions by 55% in 2030 compared to 1990, and aims to achieve carbon neutrality by 2050. This target was increased to 57% in 2022 with the publication of the REPowerEU action plan, containing measures to strengthen European energy security following Russia's invasion of Ukraine. All thirteen measures included in the legislative package were presented by the European Commission and the principle was accepted by the Member States and the European Parliament. The thirteen measures have been partially adopted since 2021 (three are still under discussion) and will have effects on the European electricity mix, in particular with the objective of increasing the share of renewable energy in the final energy mix to 42.5%¹⁷⁶, notably by speeding up the procedures for granting permits.

Figure 8.11: Average carbon intensity of electricity generation in a selection of European countries – direct emissions scope



¹⁷³. Directive 2009/28/EC

¹⁷⁴. European Council conclusions, October 2014.

¹⁷⁵. Directive 2018/2001

¹⁷⁶. Directive 2023/2413

European countries outside the European Union have mostly adopted similar objectives; this is the case of the United Kingdom, Switzerland and Norway.

The decarbonisation of electricity generation is also one of the easiest objectives to achieve, when compared to the decarbonisation of certain industry sectors, for example, which are described as “hard to abate”, see section on the *Electrification of uses*). The energy sector, particularly electricity generation, accounts for a significant share of territorial emissions in the Union: nearly a fifth in 2021, or 210 Mt_{CO2eq}. In addition, there is a consensus

on the indispensable place of electricity in the low-carbon energy landscape that many countries are moving towards.

The first results of these efforts are already visible in most European countries; the changes in the carbon intensity of electricity production for certain countries over the period 2017-2023 are spectacular (Portugal, Spain, etc.). However, some power systems still remain highly carbon-based: in 2023, in five countries, including three major countries (Poland, Italy and Germany), the intensity of electricity generation exceeds 300 g_{CO2eq}/kWh.

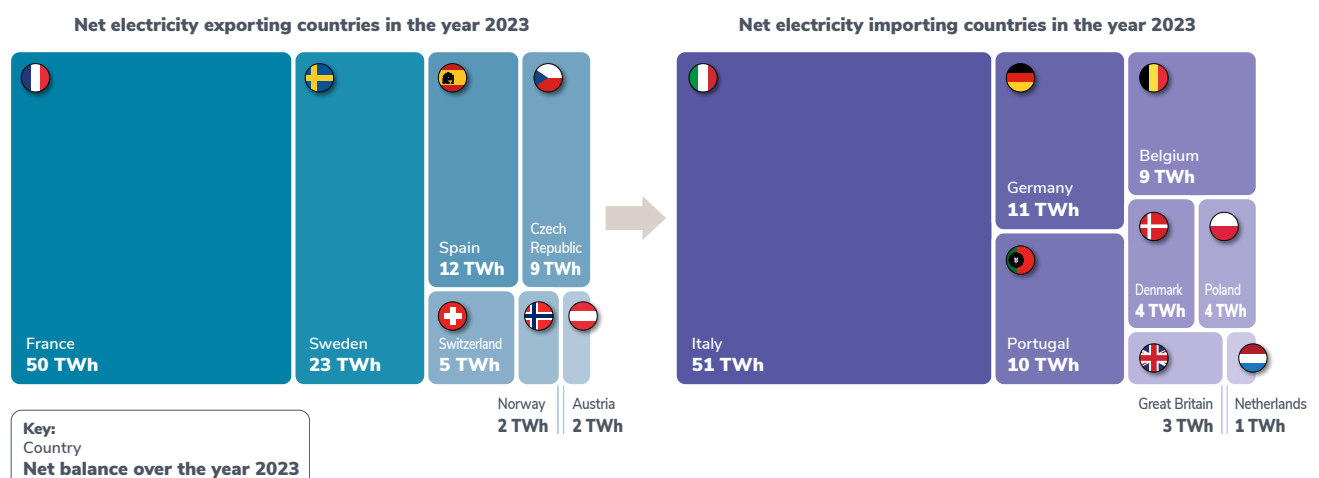
8.5 France was the leading net exporter of electricity in Europe in 2023, thanks to its low-carbon generation fleet, a feature shared by the main exporting countries in Europe

France was the leading net exporter of electricity in Europe in 2023, with a balance twice as large as that of Sweden and four times as large as that of Spain, second- and third-largest net exporters respectively. Italy was also the leading net importer, with an import balance five times greater than that of Germany, the second-largest net importer. In general, countries whose electricity production is low-emission have been the leading exporters, and conversely, importing countries are generally countries with a higher carbon intensity. The explanation is, on the one hand, linked to the fact that electricity exchanges are based on price and that the least expensive forms of energy are also the least carbon-based (wind, solar, nuclear, hydropower), and¹⁷⁷, on the other hand, to the size of the generation mix in the various countries. Countries with surplus production of these

energies at a given time export it to countries where production is more costly and, therefore, more carbon-intensive at the same time. The particular case of the Czech Republic, the fifth-largest net exporter but with one of the highest carbon intensities, could be explained by its electricity mix comprising 40% nuclear power and 38% coal-fired production. As a result, the country exports more when its nuclear fleet is more heavily used (and its generation is low-carbon), despite the high average carbon intensity of the mix. Finally, the net exchange balance is not always correlated with the size of the countries' power systems, with Sweden among the main exporters and Germany having a balance close to that of Belgium.

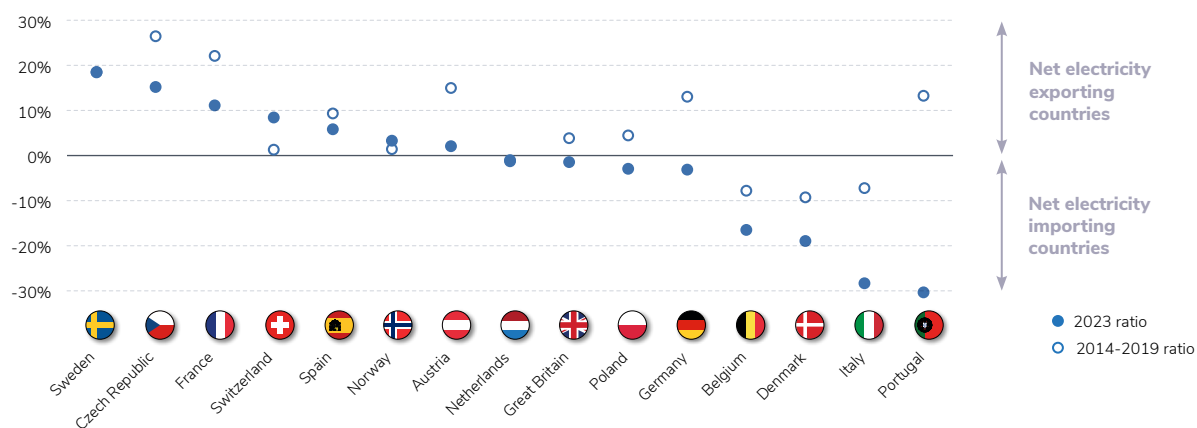
The absolute export or import balance depends in part on the "size" of its power system. Thus, the analysis of the ratio between the net exchange balance and the volume of total domestic production (see figure 12) makes it possible to qualify France's position as the leading exporter of electricity in Europe: according to this measure, it ranks 3rd behind Sweden and the Czech Republic (over

Figure 8.12: Origin and destination of electricity exchanges in Europe in 2023



¹⁷⁷. In particular, by taking into account the price of CO₂ in the context of the European Union carbon market, the emissions trading scheme (ETS).

Figure 8.13: Exchange balance/total electricity generation ratio by country in 2023 and over the period 2024-2019



Sources: Eurostat, RTE, ENTSO-E, Swiss Federal Office for Energy; calculations: RTE

the period 2014-2019, it was the second-largest behind the Czech Republic). Among net importing countries, conversely, the ratios between net balances and production level for Belgium and

Portugal reached, in 2023, 17% for Belgium and nearly 30% for Portugal, against only 2% for Germany, while the balances are close in absolute value.

8.6 Focus on a few countries

8.6.1 With a decarbonisation objective with more ambitious timescales than any other European country, Germany has completed its nuclear phase-out process, installed a record amount of solar power capacity and maintained its pace of wind power development

Germany initiated an energy transition strategy (Energiewende) in 1998. In 2000, this resulted in a law on renewable energies, or *Erneuerbare-Energien-Gesetz* (EEG), giving priority to access to these energies on the markets and setting a purchase price. The law has been amended several times (2004, 2012, 2014, 2017) to adapt their remuneration structure.

Germany then adopted a climate law, *Bundesklimaschutzgesetz* (KSG), in 2019, amended in 2021 to introduce decarbonisation objectives faster than those provided for by the European Union, in particular a reduction in the country's greenhouse gas emissions by 65% by 2030 compared to 1990, by 80% by 2040, and the achievement of carbon neutrality by 2045, i.e., five years earlier than the European objective.

To this end, the objectives for the development of renewable energies were revised upwards in 2021 and 2022 by the government: 80% of electricity generation must be from renewable sources by 2030, with the installation of 215 GW of solar power capacity, 115 GW of onshore wind power capacity and 30 GW of offshore wind power capacity. The law provides in particular for 2% of the territory to be reserved for the installation of wind farms by 2032, a percentage adapted to the scale of the Länder according to geographical constraints, as well as a simplification of the procedures for the allocation of permits.

In 2023, Germany continued to develop its renewable fleet at a sustained pace. The installation of new wind power capacity increased compared to the previous year, with 3 GW of wind power capacity installed, including 2.7 GW of onshore wind power and 0.3 GW of offshore wind power, compared to 2.4 GW installed in 2022 (including 2.1 GW for onshore wind power and 0.3 GW for offshore wind power). Germany has also developed 14.3 GW of solar photovoltaic production capacity in 2023, a record installation, bringing total available capacity to 81.8 GW. By way of comparison, the solar power capacity

Figure 8.14: Energy transition objectives in Germany and comparison with the situation at the end of December 2023

	Share of renewables in 2023 and installed capacity at the end of December 2023	Objectives defined by law
Share of renewables in the electricity mix	46%	80% by 2030
Onshore wind power	61.0 GW	115 GW by 2030
Offshore wind power	8.5 GW	30 GW by 2030 40 GW by 2035 70 GW by 2045
Solar power	81.8 GW	215 GW by 2030
Installed capacity of electrolyzers	-	10 GW

installed in Germany in the year 2023 alone corresponds to nearly 75% of the total capacity currently installed in France.

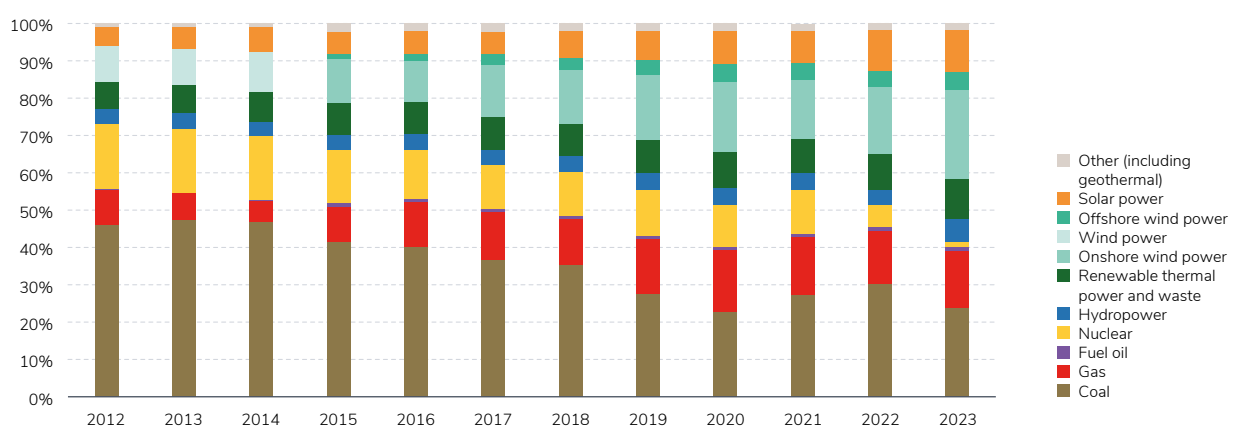
As in other countries, the wind power sector has faced difficulties linked to the current geopolitical and economic climate, which has slowed the implementation of new installation projects, particularly due to increases in the cost of materials and transport (project costs are said to have risen by almost 50% over the last two years, according to the sector¹⁷⁸).

Permit procedures are generally faster in Germany than in most other European countries: it takes 40 months to obtain a permit for an onshore wind project in Germany¹⁷⁹, compared with 65 months in France, for example. However, they are still well beyond the maximum 24-month target set by the European Union¹⁸⁰.

To support the development of renewable capacities in the coming years, the Bundesnetzagentur

(BNetzA, the Federal Network Agency) has issued several invitations to tender each year since 2017. These invitations to tender guarantee the winning tenderer income per unit of volume produced, for a period of twenty years, in addition to the income obtained on the markets when the energy produced is sold. The additional income is based on a price proposed by the candidates, which must be lower than the ceiling price set by the regulator. The latter also sets a maximum allocation volume. For onshore wind power, the invitations to tender did not attract a full quota of applications in 2023, with tenders received for 9.83 GW out of a possible 12.84 GW (i.e., 77% of the volume of the invitation to tender, compared with 88% in 2022 and 94% in 2021 and 2020). However, the volume requested in 2023 (12.84 GW) was much higher than that of 2022 (5.19 GW), the volume proposed by the players was therefore also higher and unprecedented. The sector is optimistic for the year 2024, when the price cap has been raised to €7.35/MWh¹⁸¹.

Figure 8.15: Trend in the German electricity mix between 2012 and 2023



Source: Energy Charts

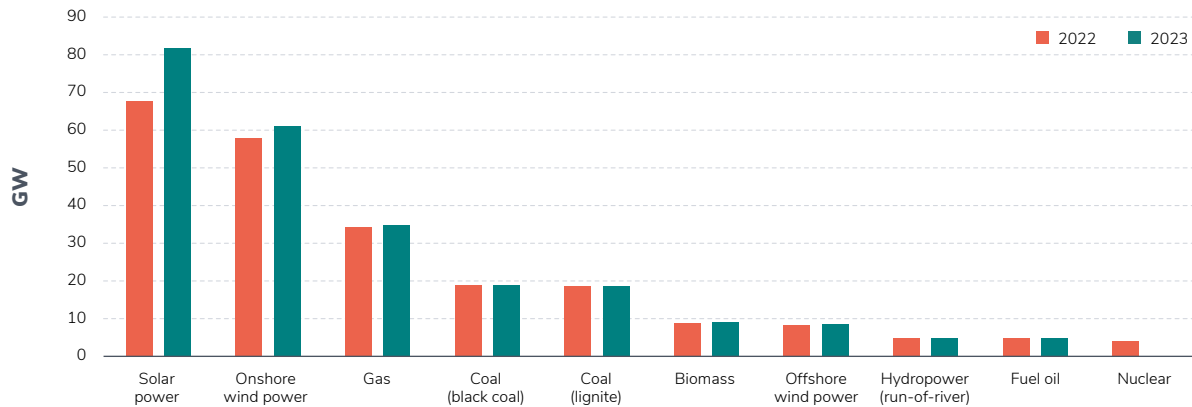
178. Clean Energy Wire, *Rising costs put 4 GW of wind energy projects planned in Germany at risk – media report*, July 2023 (in English)

179. Ember, *Ready, Set, Go: Europe's race for wind and solar*, July 2022 (in English)

180. Directive (EU) 2023/2413

181. BWE, *BNetzA gibt Höchstwert bekannt*, December 2023 (in German)

Figure 8.16: Electricity generation capacity by type in Germany at the end of 2022 and the end of 2023



Source: Energy Charts

At the same time, **Germany shut down its last three nuclear reactors in 2023, completing the nuclear phase-out process.** The shutdown of these reactors, initially scheduled for the end of December 2022, had been postponed due to the energy crisis that has affected the continent. The Isar 2, Emsland and Neckarwestheim 2 reactors finally ceased production on 15 April 2023, reducing the installed capacity by 4.2 GW, or nearly 2% of the total installed capacity in Germany. The German nuclear phase-out process, initiated in the late 1990s by the government of Chancellor Gerhard Schröder and formalised by the 2002 law (Atomgesetz), had been accelerated in 2011 following a Bundestag vote in response to the Fukushima accident¹⁸². That year, eight reactors were shut down, followed by one shutdown per year in 2015, 2017 and 2019, then three reactors in 2021 and finally three in 2023. Despite the last reactor shutdowns in 2023, nuclear power still accounted for 1.4% of the German electricity mix during the year, compared to 24% in 2010.

Wind and solar power accounted for nearly 40% of electricity generation in Germany in 2023, which is a record for the country and represents a rapid trend compared to the previous year (33% in 2022) and a clear increase compared to the 15% share in the mix in 2013.

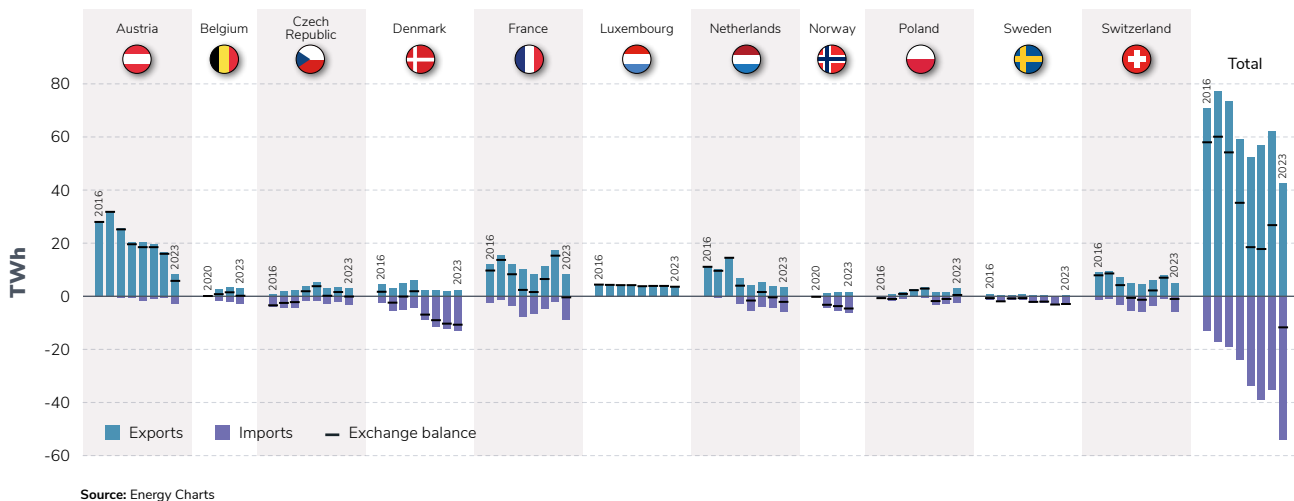
Fossil thermal energies still accounted for 40% of the mix in 2023, a value close to the average of the last 5 years. The development of renewable energies, coupled with the reduction of consumption, has therefore made it possible to avoid an increase in the share of electricity generation from fossil fuels, despite the closure of the last nuclear reactors. The distribution between the different fossil fuels has been modified: while the share of gas and fuel oil in the mix has remained more or less constant, **coal production has fallen sharply¹⁸³, reaching 24% in 2023, whereas it still represented nearly half (47%) of electricity generation in Germany in 2013.**

For the first time in twenty years, Germany imported more electricity from its neighbours in

¹⁸². On 11 March, 2011, an earthquake off the coast of Japan triggered a tsunami on the country's coast. The waves were up to 30 m high and penetrated 10 km inland, resulting in the death of more than 18,000 people. They also reached the Fukushima Daiichi nuclear power plant, disabling the cooling systems of some reactors and causing their core to melt.

¹⁸³. After a record low of 23% in 2020, a year characterised by a low level of consumption and weather conditions very favourable to wind power generation.

Figure 8.17: Electricity exchanges between Germany and its neighbours



2023 than it exported, with a negative balance of 11.7 TWh. The reasons for this development are multifactorial. While 2022 was a record year for exports to France due to very low French nuclear power generation (15.3 TWh exported to France), 2023 was characterised by a balance very close to equilibrium (0.4 TWh imported from France¹⁸⁴). This results from the restoration of French nuclear power generation and very abundant wind power generation in France during the last two months of the year, whereas these months of the year are usually marked by abundant flows from Germany to France. In addition, the volumes of electricity imported into Germany from the Nordic countries continued to increase in 2023, mainly due to economically very competitive production in these countries, due to high hydropower generation in Norway and wind power generation in Denmark. Finally, Germany's usual exports to Switzerland fell sharply, also competing with France's exports.

8.6.2 The UK has almost completed its phase-out of coal, and remains the leading developer of offshore wind power

The year 2023 was a record year for renewable electricity generation in the United Kingdom¹⁸⁵, where electricity production from wind and solar energy accounted for 41% of the electricity generation mix. The wind power source alone accounted for 35% of production, compared to only 1% in 2010. The increase in the share of renewable energies in the mix has allowed a **rapid decline in fossil-fuel thermal production, which reached its lowest level in 2023 with 39% of production, compared to 80% in 2010**. Electricity generation from gas accounted for almost all of this sector, **that from coal having continued to decline to reach a very low share of 1%, compared to 72% in 1990, and 32% in 2010**. Of the 17 coal power plants active in 2012, only the Ratcliffe-on-Soar power plant (2 GW) remained in operation at the end of 2023, after the closures in

¹⁸⁴. In the Exchanges chapter, exchanges between France and Germany and Belgium are aggregated; this is referred to as exchanges between France and the Core region (see footnote 5). Here, the decision has been made to present them on a disaggregated basis, following the practice of German TSOs.

¹⁸⁵. As a reminder: Great Britain includes England, Wales and Scotland, and its network is managed by the National Grid TSO. The United Kingdom consists of Great Britain and Northern Ireland, whose network is managed by SONI (System Operator for Northern Ireland). Unless otherwise indicated, the data in this part come from National Grid and therefore concern Great Britain. Nevertheless, the dynamics described and the analyses most often concern the United Kingdom as a whole.

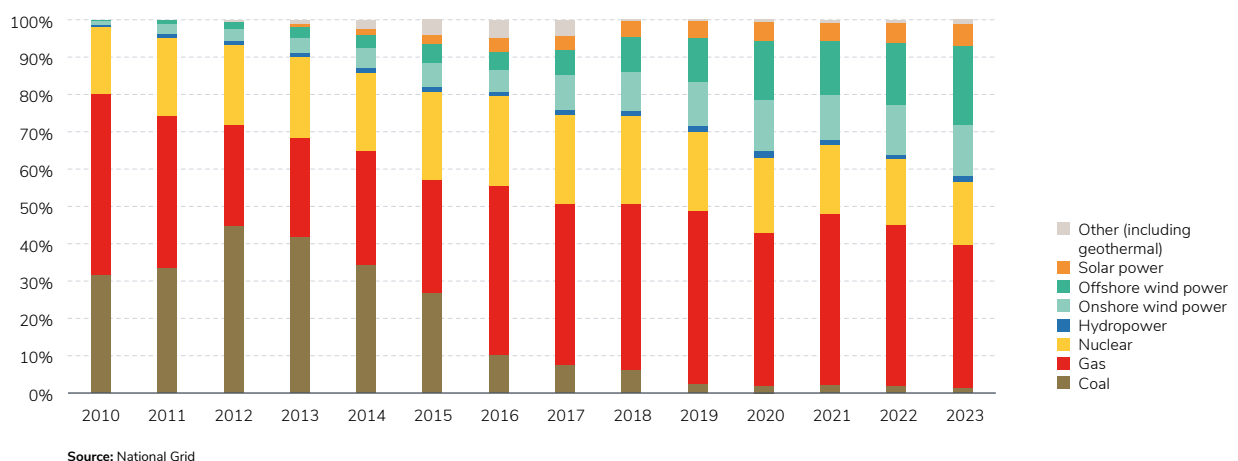
March of the West Burton A power plant (2 GW) and Kilroot power plant in September (450 MW in Northern Ireland). The closure of Ratcliffe-on-Soar is scheduled for September 2024.

With 14.7 GW of offshore wind power installed at the end of September 2023, the United Kingdom is by far the leading country in Europe in terms of the development of this sector, ahead of Germany with 8.5 GW and the Netherlands with 4.7 GW at the end of 2023. The country has the objective of installing 50 GW of offshore wind power capacity by 2030. Of these three countries, the United Kingdom also has the best load factor, at 37% (48 TWh produced), compared with 35% (26 TWh generated) and 25% (10.3 TWh produced)¹⁸⁶ respectively.

As in Germany, in 2023, the launch of new wind power projects was slowed down by the increase in the cost of raw materials. Thus, the 5 GW

invitation to tender for projects in September 2023, which proposed to pay the successful tenderers on the basis of contracts for difference¹⁸⁷, saw no tender submitted, “as a result of global inflation and the impact on the supply chain”¹⁸⁸. The proposed ceiling price was 44 GBP/MWh (~€50/MWh). The previous invitation to tender in 2022 saw 7 GW of offshore wind power selected for commissioning between 2026 and 2027. Some projects that were awarded previous tenders have experienced difficulties in the face of rising costs. After being announced as abandoned by Vattenfall in July 2023, the 1.4 GW Boreas project in the North Sea was taken over by RWE in December. The Hornsea 3 project, initially announced as being in jeopardy at the beginning of the year, has finally been confirmed for December 2023. In the face of rising installation costs, the British government announced in November that it would raise the price cap for the 2024 invitations to tender by 66%.

Figure 8.18: Trend in the British electricity mix between 2010 and 2023

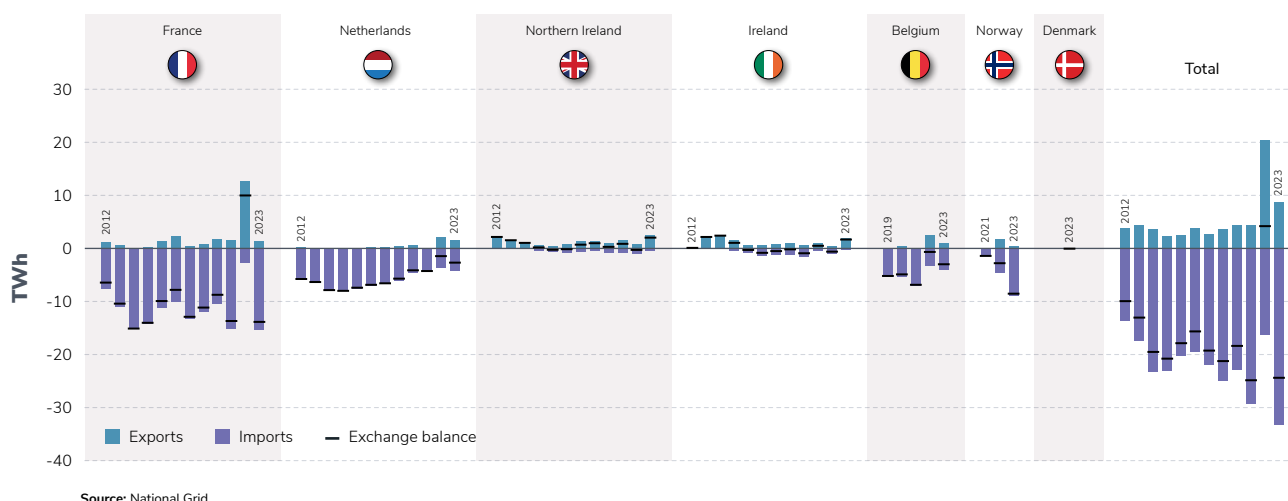


¹⁸⁶. For the Netherlands, production data are only available until the end of October 2023. The November and December data are therefore estimated.

¹⁸⁷. Contract for difference: the government conducts an invitation to tender for capacities of a specific type, here, offshore wind power. The candidates propose a price in GBP/MWh, within the limit of the ceiling price, here 44 GBP/MWh. If the market price is below the price set at the time of the invitation to tender, the government pays the difference to the producer. If the market price is above the set price, the producer pays the difference to the government. This system gives producers visibility by guaranteeing a fixed income over a 15-year period.

¹⁸⁸. Department for Energy Security and Net Zero. *Record number of renewables projects awarded government funding, September 2023* (in English).

Figure 8.19: Physical exchanges of electricity between Great Britain and its neighbours



From the point of view of exchanges, 2023 was marked by the commissioning in December of a new DC underwater interconnector (Viking Link) connecting Great Britain and Denmark. Its current capacity is 800 MW, but an increase to 1,400 MW is planned in the years to come. This interconnection is in addition to those connecting the island to Belgium, France, Ireland, Norway and the Netherlands. The last days of December saw 64 GWh imported into the United Kingdom from Denmark and 14 GWh exported.

Great Britain once again became a major importer in 2023, importing 33.2 TWh and exporting 8.8 TWh, after an exceptional year in 2022 when its electricity exchange balance proved to be a net exporter due to the drop in French production. Indeed, Great Britain generally has an import balance each year vis-à-vis its neighbouring countries, except Ireland. This situation is reflected in the prices, which are very regularly higher on the island compared to the rest of the continent (see the Price section). This import profile is explained by the possibility of using, thanks to imports, electricity

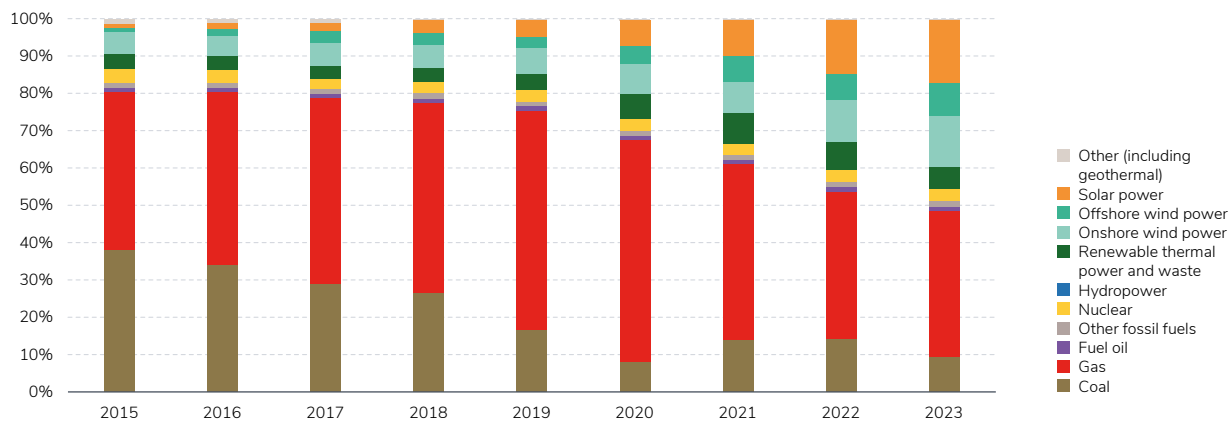
sources that are relatively cheaper than those on the island, such as Norwegian hydropower and French nuclear power.

8.6.3 The Netherlands has developed renewable energies and electrified uses at a higher rate than other European countries

The Netherlands has recorded a very rapid increase in the share of electricity generated from wind power and solar power in electricity generation, from 8% in 2015 to 39% in 2023¹⁸⁹. This rate of increase is even greater than that of Germany, whose share of electricity produced by these sources has increased from 19% to 40% over the same period. In 2023, 3 GW of photovoltaic solar power was installed in the country. The increase in renewable energies has made it possible to reduce the share of fossil fuels in production, while the share of nuclear power remained stable at around 3%. The fastest decline is in coal-fired production, whose share in the electricity mix has fallen from 40% in 2015 to 8% in 2023. The decline in gas-fired production has been more moderate, from 44% in 2015 to 38% in 2023. This

¹⁸⁹. The production data from the Netherlands is available by production source from the Dutch statistical institute, CBS, with a two-month delay. The data for November and December 2023 is unavailable at the date of writing of this report. The 2023 percentage was calculated by estimating production over the months of November and December.

Figure 8.20: Trend in the Dutch electricity mix between 2015 and 2023



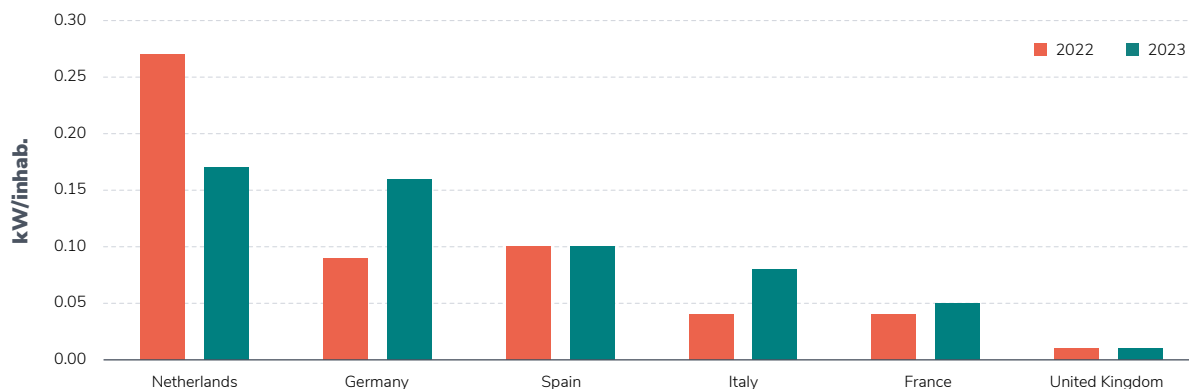
Source: CBS (data for the Netherlands estimated for November and December 2023)

moderate decline can be explained by the status of the Netherlands as the second-largest European natural gas producer, behind Norway.

The speed of transformation of electricity generation is particularly visible in the rate of solar power installation (3.6 GW installed per year over the last five years): the Netherlands has an installed capacity per capita greater than that of neighbouring

countries during the period 2022-2023. Although such a development of solar power in a northern European country, which is *apparently less sunny than those in the south* and has a small area, may seem counterintuitive, the Netherlands has massively developed solar power on buildings to reach its target of 70% electricity generated from renewable energies by 2030. Thus, more than a quarter of Dutch households are equipped with solar panels.

Figure 8.21: Photovoltaic solar power capacity installed per capita during the years 2022 and 2023 for a selection of European countries



Sources: BEIS UK, CBS, Energy Charts, ENTSO-E, Eurostat ONS, REE, RTE, Terna

This sharp increase in the share of renewable energies has had a visible effect on prices, resulting in a record number of hours characterised by negative prices on wholesale markets, a number that has more than tripled compared to previous years to 316 hours in 2023. These negative prices manifested themselves when abundant renewable production was in excess of consumption (for example, when consumption was low, such as on holidays or weekends) and the limited nature of interconnection capacities with neighbouring countries did not allow all the surplus to be exported (see the Price section).

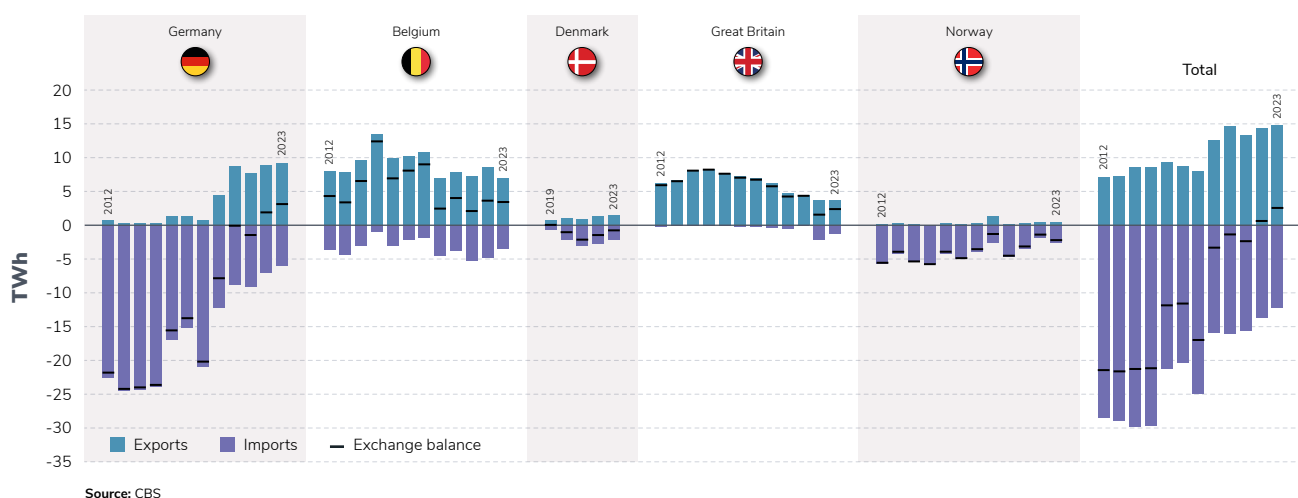
In this context of volatile wholesale prices, some electricity suppliers in the country offer contracts to individuals where the price per kWh is indexed hour by hour to the wholesale market price. These contracts are a possible lever to encourage demand-side flexibility, which is an issue for the consumption profile to come as close as possible to the profile of non-controllable renewable generation (see the Flexibilities section). According to

the Dutch Consumer and Markets Authority, by the end of 2023, 256,000¹⁹⁰ households (3.4% of households) had opted for this type of contract, three times more than at the beginning of the year. The main Dutch suppliers are also studying this type of contract, and one of them launched its offer in September 2023.

The development of renewable energies as well as the electrification of uses also present strong challenges for Dutch network operators. The transmission system operator Tennet invested 3.5 billion euros in the first half of 2023, twice the amount of the previous year, and doubled its investment forecasts over the next ten years compared to those made in 2022. The operator noted in July that in the first half of 2023, three times as many residential solar panel installations were cut off to avoid saturating the grid than in the same period in 2022¹⁹¹.

Although the trends in electricity exchanges between the Netherlands and Belgium, Denmark

Figure 8.22: Electricity exchanges between the Netherlands and its neighbours



¹⁹⁰. Dutch Energy Regulator, *Monitor Consumentenmarkt Energie, 2023* (in Dutch)

¹⁹¹. Liander, *huishoudens kunnen vaker opgewekte zonnestroom niet kwijt, 2023* (in Dutch)

and Norway have not changed in 2023, the new dynamics of exchanges with Germany and the United Kingdom initiated in previous years have continued. Exchanges between the Netherlands and Denmark began in 2019 with the installation of the COBRA interconnector, a 700 MW DC cable. As for exchanges with Germany, after many years where the exchange balance was largely imported from Germany, the trend gradually reversed before the Netherlands became an exporter in 2022 and 2023. The decline in French nuclear power generation and the high volume of French imports from Germany in 2022 have resulted in an increase in Germany's import needs from its other neighbours, including the Netherlands. Imports from the United Kingdom increased in 2022 and 2023 due to higher wind power generation in this country.

8.6.4 After 2022, a year heavily marked by the energy crisis, the Spanish power system returned to relative normality against a backdrop of increased renewable production

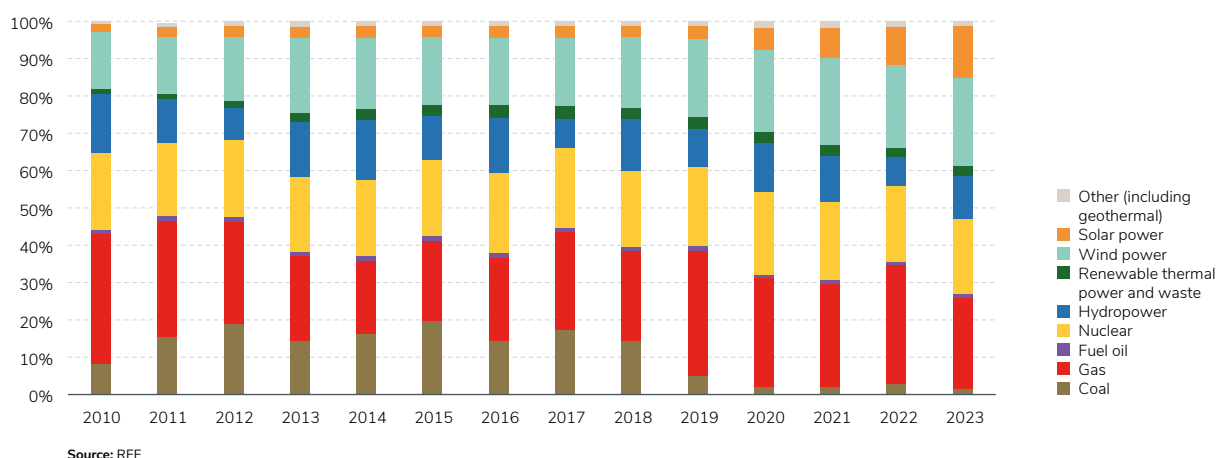
The year 2023 was in line with historical trends in Spain, with an increase in the share of wind and solar power in the production, which amounted

to 23% and 14% respectively. As for hydropower generation, after a dry year in 2022 and exceptionally low power generation, the year 2023 saw it approach the historical average (11% of the electricity mix compared to 12% on average during the period 2010-2022) thanks to more abundant rainfall. The generation of electricity from gas has declined the most in the Spanish mix compared to the previous year, from 32% to 24% in one year.

While installed wind power capacity was relatively low in 2023 (600 MW for a total capacity of 30.7 GW), installed solar power capacity increased by 23% to 4.6 GW, for a total fleet of 24.6 GW at the end of the year.

The wind power generation source experienced its biggest development in the 2000s, during which 20 GW were installed, thanks to a dynamic local industry, ambitious government objectives and effective support mechanisms. In 2012, Spain was the fourth largest nation in the world in terms of total capacity with a wind farm capacity of nearly 23 GW¹⁹². The sector then experienced a sluggish period, especially with the cessation of

Figure 8.23: Spanish electricity mix between 2010 and 2023



192. Irena, *30 Years of Policies for Wind Energy*, 2013 (in English)

support mechanisms in times of economic crisis. Then in 2018, the government adopted a plan to achieve 100% renewable electricity generation in 2050 and a new royal decree made the development of renewable energies attractive again¹⁹³. Thus, 8 GW were installed between 2018 and 2023 to reach 30.7 GW at the end of 2023.

The solar power source saw 4 GW installed before 2010, then a plateau also in the early 2010s, before experiencing a meteoric increase and quintupling the total capacity of 5 GW installed in 2018 to 24.6 GW at the end of 2023. Production from other sources has remained relatively stable over the last ten years, except for coal-fired power plants, whose installed capacity has been divided by four in ten years, from 12 GW in 2013 to 3 GW at the end of 2023.

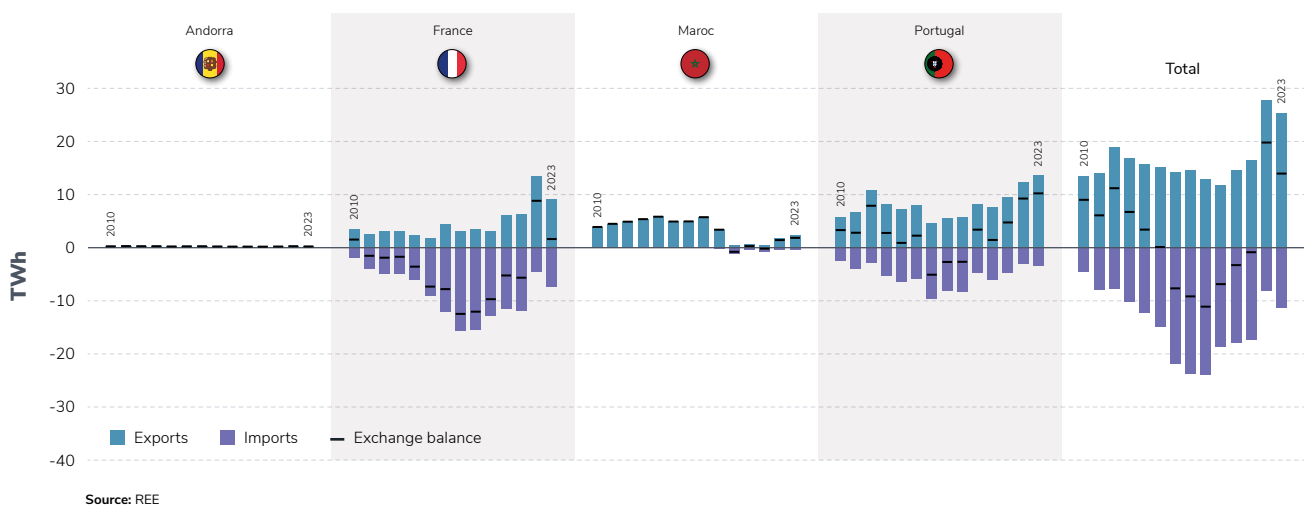
While Spain was traditionally an importer from France, it remained a slight exporter to France in 2023, for the second year in a row, with a positive balance of 1.6 TWh. After 2022, when the

influence of the “Iberian mechanism” on electricity in Spain favoured the export of large volumes to France, exchanges in 2023 resumed a more traditional cyclical rhythm characterised by exports from Spain to France during times of high renewable production and imports in the opposite case.

Exchanges with Andorra have not changed, as in previous years, Spain remained almost exclusively an exporter to the principality of 80,000 inhabitants, with a balance between 200 and 300 GWh.

Spain and Morocco are connected by two interconnections of 700 MW each installed in 1997 and 2006. A third 700 MW interconnection project has been under consideration since 2019 and could be completed in 2026. After having been mainly an exporter to Morocco between 2010 and 2018, Spain saw its exports decrease and its imports increase from 2019, in particular because of the installation of a 1.4 GW coal-fired power plant in Morocco at the end of 2018.

Figure 8.24: Physical exchanges of electricity between Spain and its neighbours



193. Royal Decree 15/2018

Glossary

Mot clé	Définition
Adjusted (for weather and/or calendar effects) consumption	The consumption that would have been observed if temperatures had been normal (as defined below "Normal temperatures") and excluding the consumption of 29 February for leap years.
ASN	The Nuclear Safety Authority (<i>Autorité de sûreté nucléaire</i>) is the public entity which carries out, on behalf of the French state, the missions of nuclear safety control, radiation protection (workers in the nuclear industry, environment, local communities) and the public's information, "to protect workers, patients, the public and the environment from the risks associated with nuclear activities".
Auto-consumption	Consumption, by a consumer, of all or part of the electricity generated by their own production installation. Closely related to the English-language concept of "prosumer".
Balancing mechanism	The mechanism whereby RTE procures dispatchable reserves of supply to balance supply and demand close to real time. RTE can activate production and/or load ramp-up and/or ramp-down offers from participants in the mechanism.
Capacity factor	For a given production type, the capacity factor is defined as the ratio between production and installed capacity. In RTE's Electricity report, the monthly and yearly capacity factors correspond to the monthly or yearly average of the half-hourly capacity factors.
CO _{2eq}	Carbon dioxide equivalent – a comparative emissions measurement index of different greenhouse gases representing their global warming potential. The volume of gas emitted is converted into the equivalent quantity of carbon dioxide needed to reach the same global warming potential.
Commercial exchanges	Commercial exchanges are the result of a commercial transaction between market participants which are located in different countries (or bidding zones).
Core	Capacity calculation and market coupling region. The member countries are: France, Germany, Belgique, the Netherlands, Austria, Slovenia, Poland, the Czech Republic, Slovakia, Croatia, Hungary and Romania.
Coverage rate	The ratio between the output of a given generation type, and demand. In the Electricity review, the monthly and yearly coverage rates correspond to the average of half-hourly coverage rates.
Demand peak	The hours where electricity demand is highest.
Dispatchable production unit	A production unit which can be started up and/or modulate its output on demand (thermal and nuclear power plants, hydroelectric plants with pumped storage...).
EPEX SPOT	One of the power exchange operator among those designated by regulators. Power exchange operators are tasked with the organisation of market coupling, and provide insurance for transactions on the day-ahead and intraday markets. The operators approved for France by the <i>Commission de régulation de l'énergie</i> are EPEX SPOT and Nord Pool.
EPR	The European Pressurized Reactor, or EPR, is a nuclear reactor design of the pressurized water reactor (PWR) type. The EPR is part of the so-called 3rd generation of PWR.
Fossil-fired thermal/fossil fuels	Electricity generation from thermal power plants running on gas, coal or oil.
Grand Carénage	An large industrial programme designed to upgrade the safety of existing nuclear plants.
Gross consumption	Countrywide electricity consumption (Corsica included, overseas territories not included), taking into account transmission losses but not the consumption of pumped-storage plants.
Intraday prices	The prices of electricity transactions for delivery on the same day.

Mot clé	Définition
LNG	Liquefied natural gas
Lock hydropower plants	Mostly located in lakes downhill from mid-altitude mountains, those plants have a filling duration of 2 to 400 hours. They provide daily or, more rarely, weekly flexibility to the power system (daily demand peak, between business and non-business days...).
NEBEF	The French demand-respond products trading mechanism (<i>Notification d'Échange de Bloc d'Effacement</i>)
Normal temperatures	Average of past temperature timeseries that are considered representative of the current decade. They are based on Météo France data, and are computed by RTE at the country level thanks to a panel of 32 meteorological stations across France.
Other hydro power plants	The plants in the "other" category are tidal energy plants and pumped-storage plants. Tidal energy plants harvest the energy from the tides in coastal areas where the tidal range (the height difference between high- and low-tide) is large. This range is used to generate electricity by exploiting the height difference between two basins separated by a dam. Pumped-storage plants, operating in pumping-generation cycles between a downhill and an uphill reservoir, thanks to reversible turbines-pumps, are efficient storage assets which contribute to the balance of the power system. When the reservoirs also have natural inflows, the turbine is categorized as "mixed pumped storage", otherwise as "pure pumped storage".
Physical exchanges	Physical exchanges account for the actual electricity flows on interconnectors between countries, and can differ from commercial exchanges.
PPE	The French Multiannual Energy Plan (<i>Programmation Pluriannuelle de l'Énergie</i>)
Renewable thermal and waste	Electricity generation from thermal power plants running on fuels such as: bioenergy, paper waste, renewable household waste, non-renewable household waste...
Reservoir hydropower plants	Located downhill from mid- and high-altitude mountains, those plants have a filling duration of over 400 hours and provide seasonal flexibility and storage to the power system.
Run-of-river hydropower plants	Mostly located in plains, those plants consist in a small-height dam and can be filled in under two hours. Therefore, their flexible potential is small and their production depends on the river's flow rate.
SFEC	French Strategy on Energy and Climate (<i>Stratégie française énergie-climat</i>)
SNBC	National Low-Carbon Strategy (<i>Stratégie nationale bas-carbone</i>).
Spot prices	The electricity prices set by the day-ahead market coupling, for each hour of the next day
STEP	Pumped hydro storage plants (<i>stations de transfert d'énergie par pompage</i>) are hydroelectric power plants that have the ability, during off-peak hours, to pump water from a lower basin to an uphill lake. The water is then released downhill during peak hours to produce electricity.
Supply-demand balance	The possibilities for storing electricity are limited. Therefore, supply and demand must match at every instant, which is RTE's responsibility to ensure. An imbalance between supply and demand causes the power system's frequency to deviate from its nominal value of 50 Hz.
Temperature-sensitivity of consumption	Refers to the variation of electricity demand linked to the variation of temperature. For example, demand increases in winter, when the weather is cold, due to the high prevalence of electric heating in France.
Water reserves	Countrywide French water reserves represent the aggregate weekly filling level, in %, of reservoirs and lakes where there are hydropower production assets. Water reserves are expressed in terms of "producible energy", in MWh, given the reservoir filling.
Wholesale prices	Can refer either to the spot price (cf. definition), or to forward prices, for which the delivery date ranges from the next week to the next year.