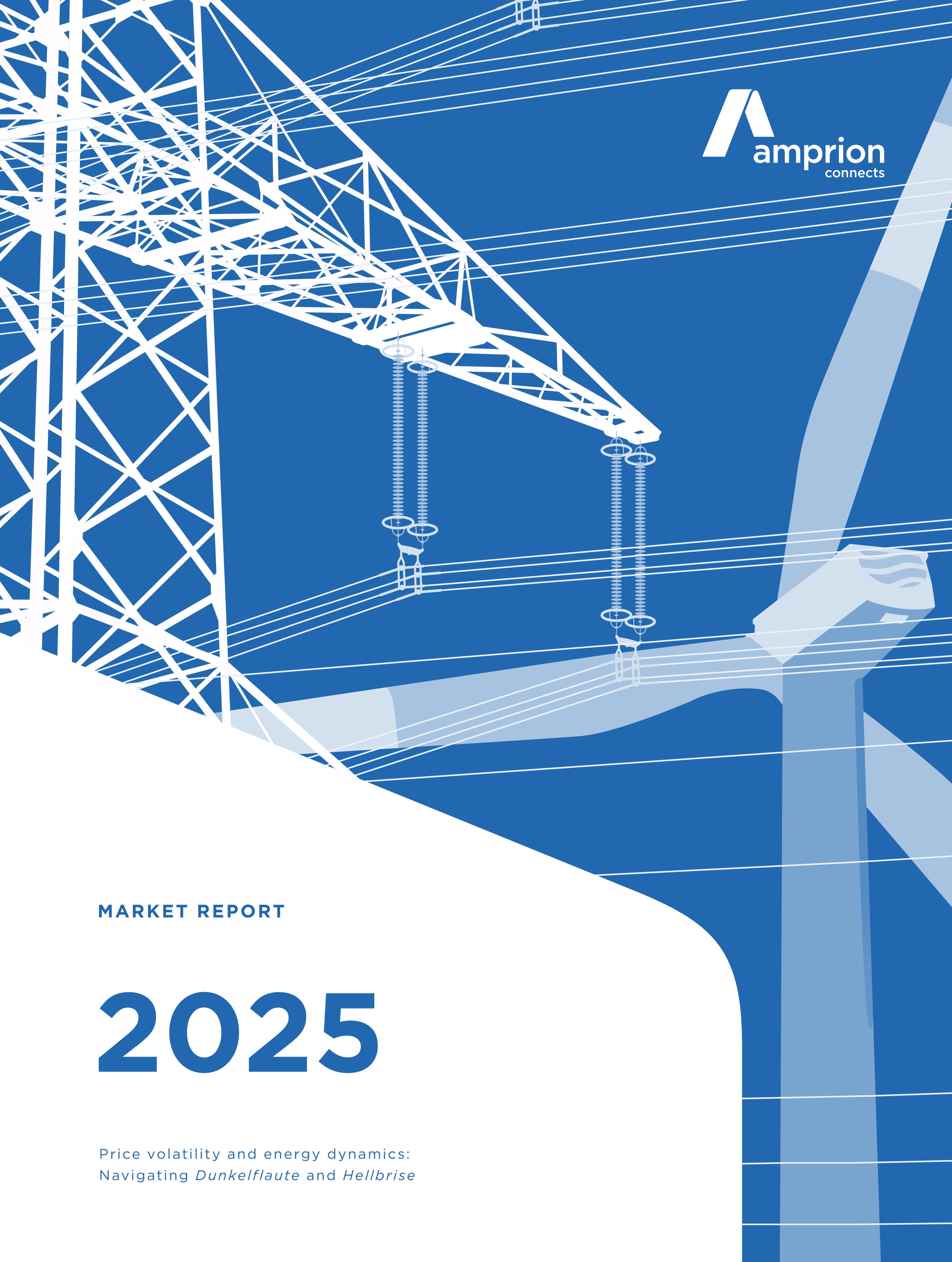


MARKET REPORT

2025

Price volatility and energy dynamics:
Navigating *Dunkelflaute* and *Hellbrise*

This Amprion annual market report analyses the developments of the German[1] and European electricity market and the effects on the underlying transmission grid. The report addresses the electricity market developments and the European transmission grid of 2024. This year's focus is on the increasing price volatility due to the new records in the expansion of renewable (photovoltaic) energy sources in Germany as well as its effects on the market and grid.

For further information on the previous market reports and additional material on the Flow-Based Market Coupling concept, please visit the Amprion website: amprion.net/market/market-report

1 For the purpose of legibility, the report refers to the "German bidding zone" which also includes Luxembourg.

CONTENTS

EXECUTIVE SUMMARY

The year 2024 experienced an unprecedented period of low renewable electricity generation (*Dunkelflaute*), lasting almost 11 days, the longest since 1982.

In 2024, Germany's electricity market saw record growth in renewable energy generation capacity and further shifts in its import-export balance. Germany remained a net electricity importer due to reduced flexible generation capacity, while renewable energy production reached a record 60% of net generation. The long-lasting, almost two-week *Dunkelflaute* period in November indicates potential future resource adequacy challenges. However, favourable weather conditions contributed to moderate electricity prices on average. Overall, only few price peaks occurred during this period.

About half of German PV producers receive fixed feed-in tariffs with no exposure to market prices and no incentive to reduce their production in case of negative prices.

A glut of cheap renewable electricity turned prices negative for several hours during the summer. This development was driven especially by the total installed PV capacity, which approached 99 GW by the end of 2024. In contrast to adjustable wind production, about half of PV capacity receives fixed feed-in tariffs without exposure to time-varying market price signals. Consequently, these PV producers are not incentivised to reduce their production in times of high overall renewable electricity production exceeding electricity demand. These so called *Hellbrise* periods will provide substantial challenges to network and system operation in terms of congestion management and especially system balancing. During these periods, this excess of generation requires network operators to activate their balancing reserves and solve congestions close to real time. More flexibility of consumers, of small-scale PV systems and of storages is therefore required to better integrate the renewable electricity production into the grid.

There is a trend towards increasing price volatility, driven by the rising share of renewable energy production and the decline in flexible electricity generation capacity.

In 2024, a record of 16.7 GW of PV capacity was built, alongside increases in wind power capacity and decommissioning of coal power plants. This shift positively influenced average wholesale electricity prices but also led to high volatility, with day-ahead prices ranging from –135 €/MWh to +936 €/MWh. The volatility was driven by the growing renewable energy share and reduced flexible generation capacity, prompting a surge in battery storage system connection requests.

Amprion continues to enhance the transmission grid and to improve cross-zonal trading capacities, to reap the full benefit of the integrated European electricity market.

Price spreads between European bidding zones and redispatch needs in Germany reflected transmission constraints and diverse generation portfolios. This emphasises the need for grid reinforcement and demonstrates the impact of our completed grid expansion projects. For example, the 94 km-long line from Ganderkesee to Wehrendorf, commissioned at the end of 2023, significantly relieved Germany's biggest congestion in the Emsland region.

In case of a German bidding zone split, the additional subsidies for renewable energies would exceed the savings in redispatch.

The ongoing discussion about the European bidding zone configuration reflects the interdependency of cross-zonal price spreads and redispatch costs. While a split of the German bidding zone would reduce redispatch costs, it would also come with various drawbacks. Payments to renewable electricity producers would have to increase to compensate lower prices for renewable electricity sold in the split zonal market. This aspect, and further considerations described in the Bidding Zone Review Study by the European TSOs, should be considered carefully before taking any decision on a potential bidding zone reconfiguration.

Legislation needs to constantly review regulation to accompany the arising challenges of the progressing energy transition.

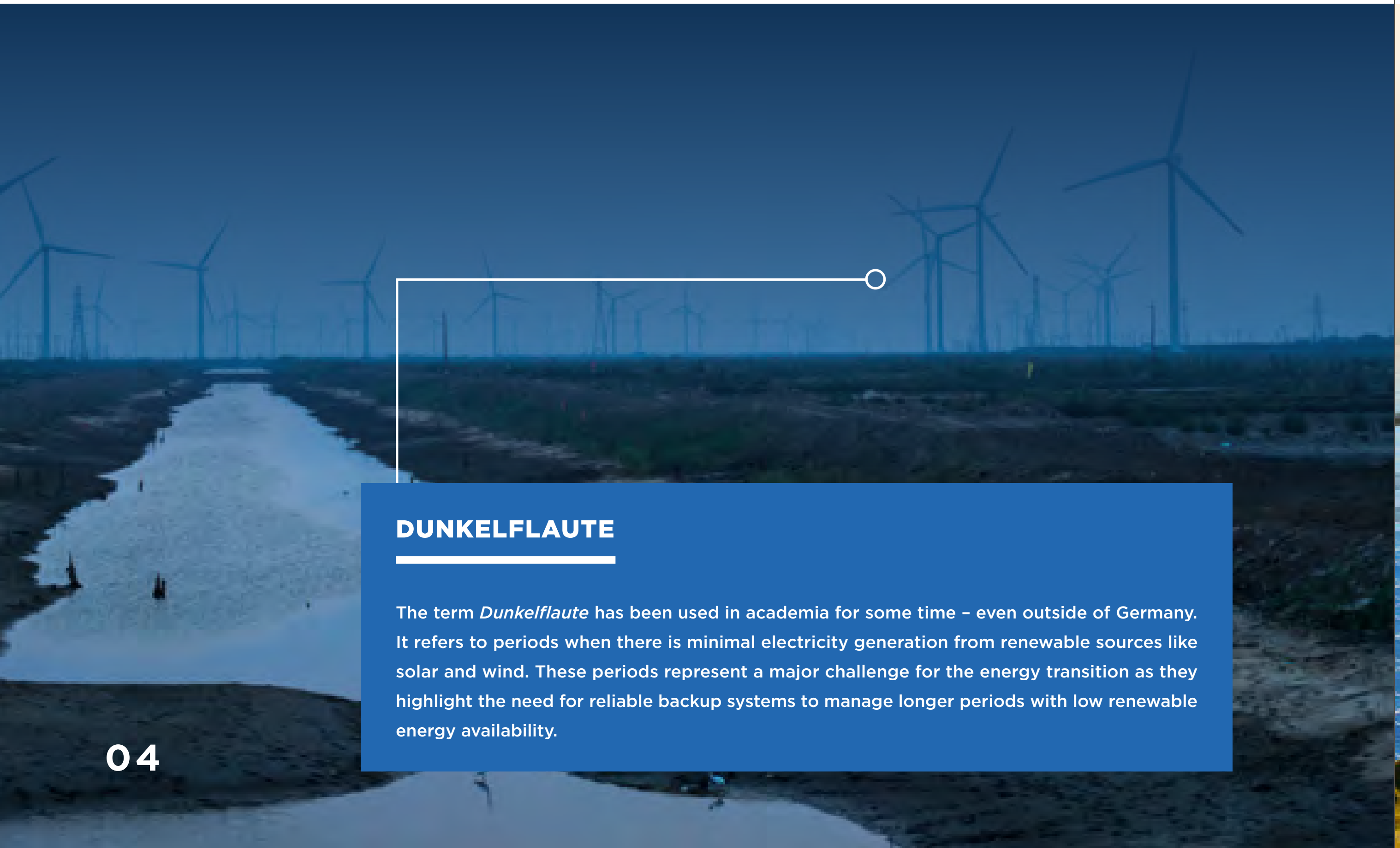
Overall, Germany's energy transition is promising but comes with challenges. To secure a sustainable energy future, it is vital to enhance grid infrastructure and expand flexible generation capacity as well as integrating flexibilities in demand and storage. Proactive measures will be essential in addressing market stability and resource adequacy concerns as renewable energy production continues to grow in relevance for the market.

INTRODUCTION

European electricity market

The European electricity market development in 2024 was characterised by significant advancements and ongoing challenges. Germany continues its electricity system transition with increasing integration of renewable energy sources, shifts in import-export balances and higher price volatility. This report explores these developments, providing insights into the complexities of Germany's energy transition. From record-breaking growth in photovoltaic electricity production capacities to the intricacies of price spreads and system operations, the analysis offers a comprehensive overview of the current state and prospects of the German electricity market, with implications for industry stakeholders and policymakers alike.

AMPRION CONNECTS ELECTRICITY MARKETS ACROSS BORDERS



DUNKELFLAUTE

The term *Dunkelflaute* has been used in academia for some time – even outside of Germany. It refers to periods when there is minimal electricity generation from renewable sources like solar and wind. These periods represent a major challenge for the energy transition as they highlight the need for reliable backup systems to manage longer periods with low renewable energy availability.

About Amprion

Amprion GmbH is one of four transmission system operators in Germany. Our 11,000 kilometre-long extra-high-voltage grid transports electricity in an area from the North Sea to the Alps. One third of Germany's economic output is generated there. Our lines are the lifelines of society: they secure jobs and quality of life for 29 million people. We keep the grid stable and secure – and are paving the way for a climate-neutral energy system by expanding our grid. More than 3,100 employees in Dortmund and at more than 30 other locations help to keep the lights on. We also take on overarching tasks for the interconnected networks in Germany and Europe.

HELLBRISE

In contrast, the term *Hellbrise* is relatively new. It describes periods when electricity generation from solar and wind is particularly high. Historically, this has always been seen as a positive situation with large amounts of low-cost electricity being available for consumers. However, this large overall generation of many small-scale individual production units has now reached a level which has noticeable effects on the overall grid and market.

MARKET ANALYSIS 2024

PRICE DEVELOPMENT AND VOLATILITY

Renewable electricity production, particularly from photovoltaics (PV), had a substantial impact on the German electricity market in 2024: prices were more volatile than ever before. The installation of new PV capacity continued to break records, with 16.7 GW of PV capacity added, surpassing the previous record of 15.1 GW in 2023. Additionally, 0.7 GW of offshore wind and 2.6 GW of onshore wind power were brought online, while approximately 6 GW of lignite and hard coal power plants were decommissioned. At the same time, prices became part of the public debate: in May for reaching new lows with negative prices over sunny weekends and during December for hitting record highs. In the public debate, both events were linked to highs and lows in production by renewables.

There is a trend towards increasing price volatility, driven by the rising share of renewable energy production and the decline in flexible electricity generation capacity.

The data shows PV in electricity supply increased from 12% to 15%, while onshore wind power remained steady at 26%, although in total 3.3 GW of wind capacity was installed in 2024.[2] The contribution of natural gas rose from 11% to 13%, and coal's share decreased from 26% to 23%, as detailed in Table 1. Coal-generated electricity declined to about 98 TWh, down from 118 TWh in 2023 and 166 TWh in 2022, while natural gas generation was around 57 TWh.

	Solar	Wind onshore	Wind offshore	Hydro	Bio-mass	Natural gas	Coal	Nuclear	Others
2022	11%	20%	5%	5%	8%	11%	33%	6%	2%
2023	12%	26%	5%	6%	8%	11%	26%	2%	3%
2024	15%	26%	6%	6%	8%	13%	23%	0%	3%

TABLE 1 Overview of electricity generation in Germany in 2022–2024 by source[3]

Renewable energy's share of net electricity generation reached a record 60% in 2024, up from 58% in 2023. On average this increase positively influenced the wholesale electricity price, with day-ahead prices averaging around 78 €/MWh, compared to 95 €/MWh in 2023 and 235 €/MWh in 2022. But price volatility was high. The maximum day-ahead price in the German bidding zone was +936 €/MWh

2 Source: wind-energie.de/fileadmin/redaktion/dokumente/publikationen-oeffentlich/themen/06-zahlen-und-fakten/20250115_Status_des_Windenergieausbaus_an_Land_Jahr_2024.pdf

3 Source: transparency.entsoe.eu

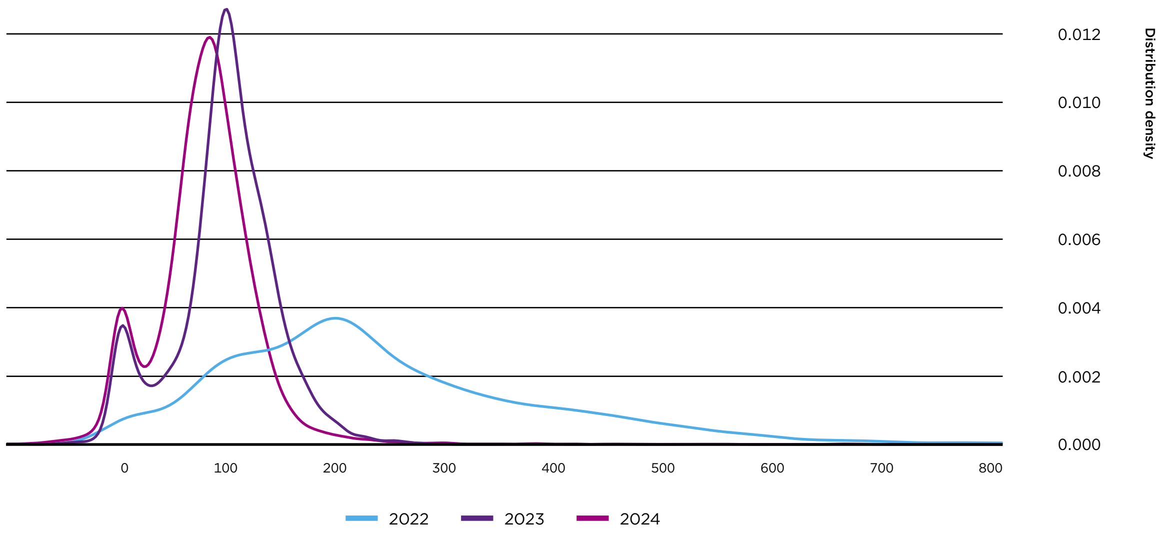


FIGURE 1 Development of hourly day-ahead price distribution 2022–2024 in €/MWh[4]

on 12 December, while the minimum was –135 €/MWh on 12 May. Day-ahead prices exceeded 300 €/MWh in 41 hours (about 0.5% of the total time), compared to 3 hours in 2023 and 2,350 hours in 2022. In contrast, negative prices were recorded in 457 hours (approximately 5% of the total time) in Germany, compared to 300 hours in 2023 and 70 hours in 2022.

Overall, there is a trend towards increased price volatility, driven by the rising share of renewable energy and the decline in flexible generation capacity. The daily average maximum price spread of day-ahead prices increased from 33 €/MWh back in 2020 to 99 €/MWh in 2023 and 112 €/MWh in 2024.

This volatility has contributed to a surge in grid connection requests for battery storage systems, currently exceeding 200 GW in Germany's transmission network.

Examining the normalised distribution curves[5] of electricity prices from 2022 to 2024 (see Figure 1) reveals a similar price distribution in 2024 and 2023, with a shift in the median from 98 €/MWh to approximately 80 €/MWh. This shift correlates with the shift of renewable energy share from 2023 to 2024, as shown in Figure 2, illustrating the annual increase in renewable energy share, especially at higher levels. The year 2022 represents an exceptional year, in terms of price distribution, caused by the energy crisis. The renewable energy share in 2022 was nearly normally distributed around 45% but the energy crisis accelerated the expansion of renewable production capacity. In the following years, an increase in installed capacity of renewable energy caused a significant shift to the right, peaking at 70–80%.

4 Source: transparency.entsoe.eu

5 Normalised distribution curves (F(x) = 1), i.e. the sum under the curves equals 1. The y-axis shows how often a value range (x-axis) occurs proportionately to another value.

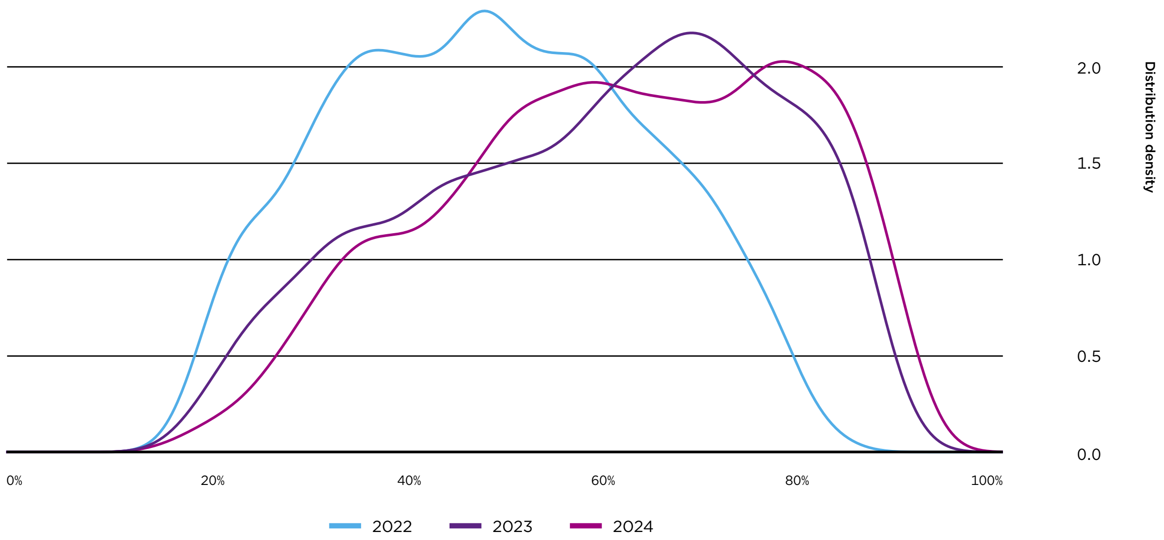


FIGURE 2 Development of renewable energy share distribution 2022–2024[6]

The hour with the highest recorded renewable energy share in 2024 was on 23 August at 10 a.m. with a share of 91%, in 2023 it was 88%. The hour with the lowest renewable energy share was recorded on 7 November at 4 a.m., with a share of 15%, as depicted in Figure 3.

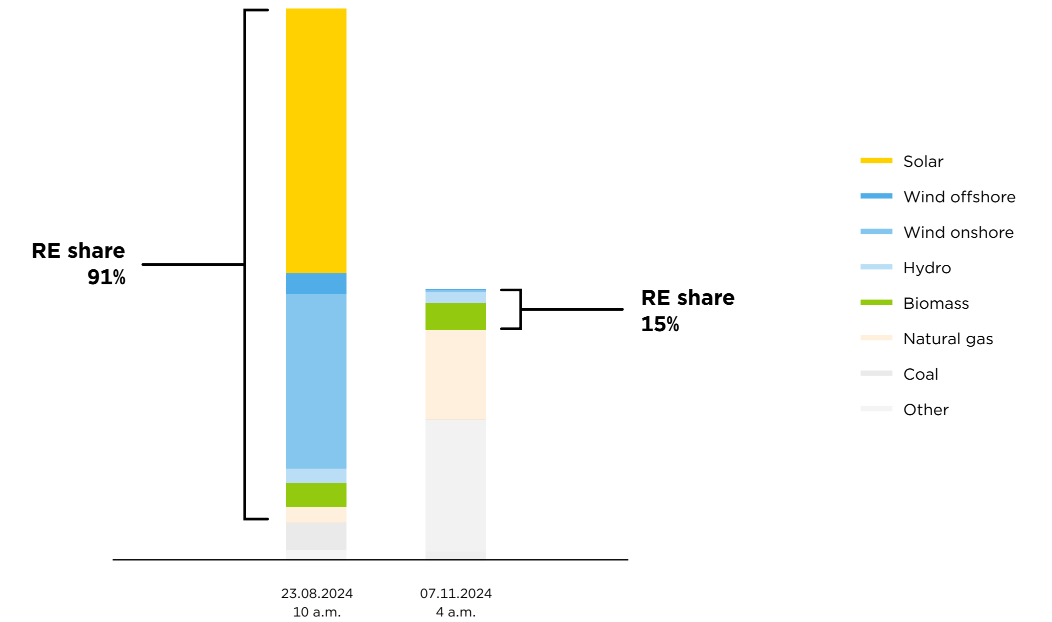


FIGURE 3 Highest and lowest share or renewable electricity (RE) generation in Germany in 2024[6]

6 Source: transparency.entsoe.eu

EXPORTS AND IMPORTS

Electricity exports and imports to and from bidding zones are characterised by their net positions. A positive net position indicates an exporting bidding zone, while a negative net position shows an importing bidding zone.

In 2024, Germany remained a net importer of electricity, continuing the trend already observed in 2023. Electricity imports rose by approximately 13 TWh, from 54 TWh in 2023 to around 67 TWh, compared to 37 TWh in 2022. Conversely, exports decreased by about 4 TWh, from 42 TWh in 2023 to roughly 38 TWh, down from 65 TWh in 2022. This resulted in a net import of about 28 TWh, a stark contrast to the net export of 28 TWh in 2022 (see Figure 4).

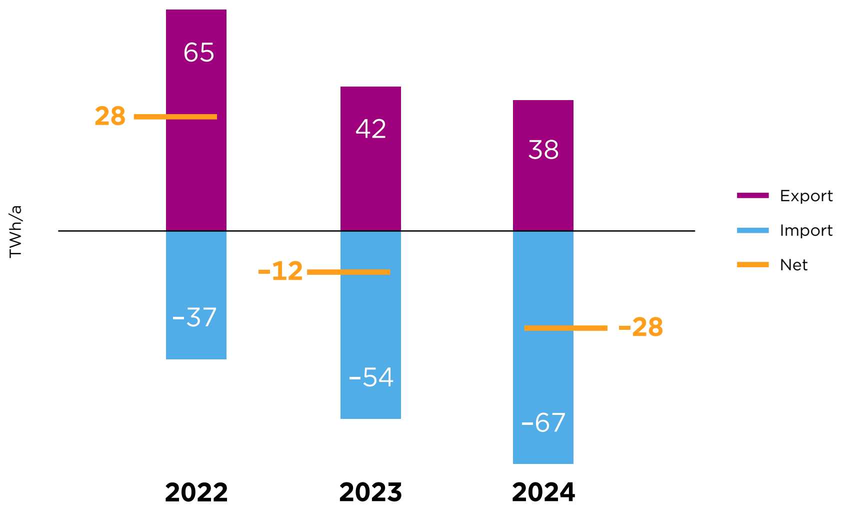


FIGURE 4 Yearly day-ahead exports and imports of Germany for 2022–2024[7]

7 Source: transparency.entsoe.eu

A significant factor influencing Germany's import-export balance is the reduction in flexible generation capacity. The phase-out of nuclear energy in 2023 significantly increased electricity imports. This topic has been widely covered in the media, often highlighting the high share of nuclear energy imports following the shutdown of domestic nuclear plants. However, the situation is more complex than it appears at first glance. Not all imports and exports are connected to consumption or production in Germany. Besides becoming a net importer, the country's central location in Europe, coupled with its robust transmission network and high interconnection capacities, makes it a crucial transit country in the European electricity market experiencing significant north-south and west-east flows.

Often, imports and exports occurred simultaneously, with transit accounting for about 35% of imports which are then exported to other countries. These imports and exports cannot only occur simultaneously but also be counterintuitive as exports can flow from nominally higher-price bidding zones into bidding zones with lower prices. This is an effect of Flow-Based Market Coupling in which the imports and exports are optimised to maximise overall welfare over several bidding zones. Due to the central location of Germany within the Core Capacity Calculation Region, the share of such non-intuitive flows is about 14% for Germany in 2024.

Due to its central location, Germany is a crucial transit country in the European electricity market. Around 35% of its imports are transits, resulting in significant north-south and west-east flows.

Germany's main electricity trading partners include France, Austria, Switzerland and Denmark, see Figure 5. Except for Austria, these are also the main import countries for Germany. Notably, the relationship with France has completely reversed since 2022, when Germany was a significant net exporter during the vast outages of nuclear power plants in France. Austria remains the country to which Germany exports the most.

Examining the 2024 electricity mix of Germany's main trading partners reveals that France and Switzerland have high nuclear shares at 69% and 46%, respectively. In contrast, Austria and Denmark are notable for their significant renewable energy shares, at 89% and 78%. Considering all these factors, especially transits, the composition of Germany's electricity imports paints a different picture: The share of renewable energy in German imports was about 51%, while nuclear energy accounted for approximately 28%.

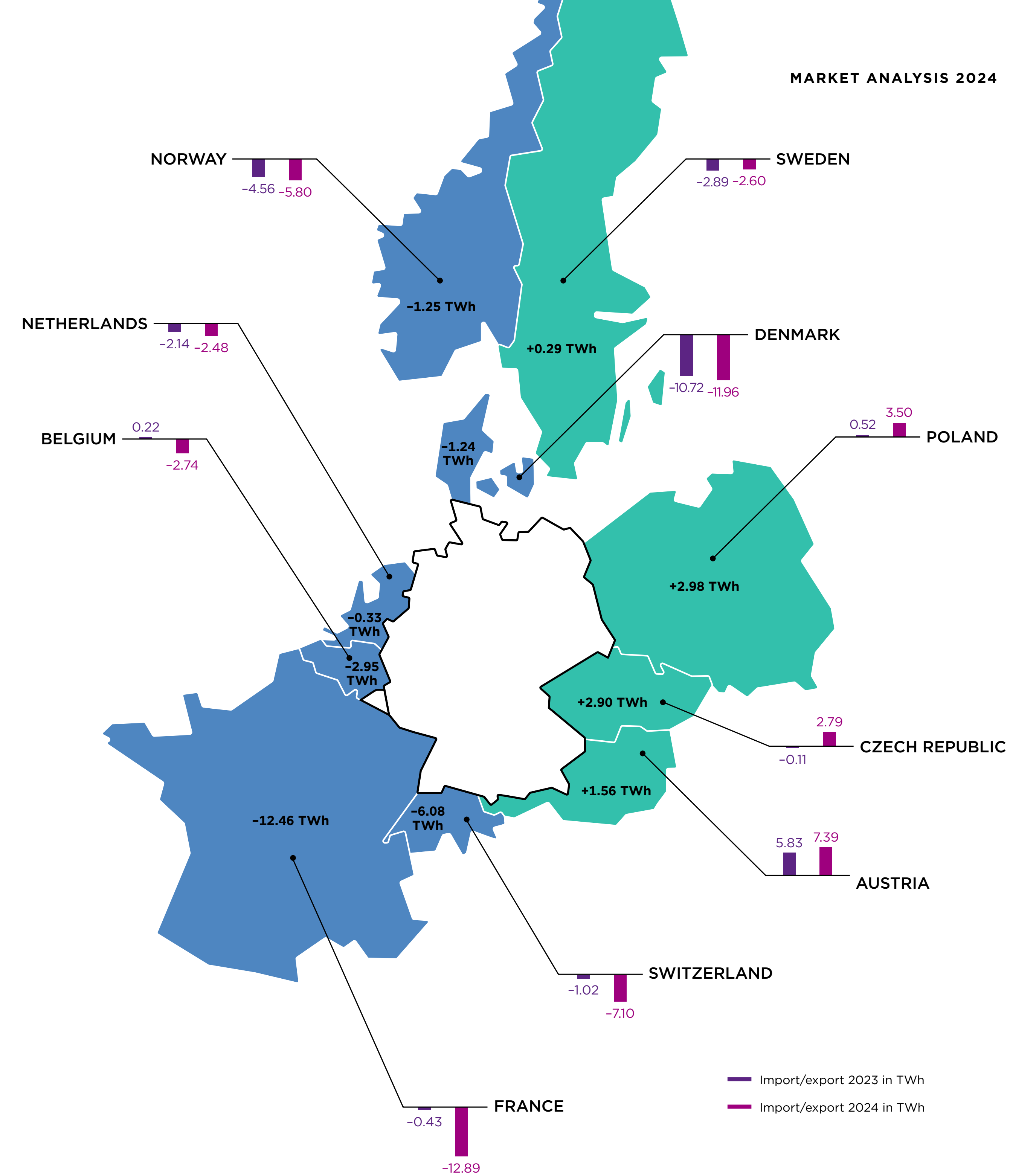


FIGURE 5 Yearly day-ahead net exports (positive +) and imports (negative −) of Germany with its neighbouring countries in 2023 and 2024[8]

8 Source: transparency.entsoe.eu

EXCURSUS

CORE INTRADAY CAPACITY CALCULATION AND ALLOCATION IN 2024

Intraday trading received a major overhaul in 2024: Single Intraday Coupling (SIDC) has been enhanced by introducing intraday auctions (IDAs), which complement continuous trading by providing additional trading opportunities at specific times within the day. IDAs determine prices for intraday cross-border transmission capacities to reflect their shortage at a given time. Thereby, an adequate price signal is sent to the market. This is a novelty in the intraday market. Before the introduction of IDAs, transmission capacities were only allocated on a first-come first-served basis without price setting in the continuous intraday trading. The newly introduced auctions allow market participants to adjust their positions based on updated information, improving price discovery and market efficiency.

SIDC is a mechanism designed to optimise cross-border electricity trading at the day of delivery. It enables market participants to engage in continuous trading across European bidding zones, optimising the use of transmission capacities and fostering more efficient electricity markets. SIDC is part of the larger effort to integrate European energy markets, allowing for better alignment of electricity supply and demand and enhancing the integration of renewable energy sources. It allows for adjustments closer to real time and helps balance the grid by enabling market participants to respond promptly to changes in demand or supply conditions.

Over the last years, SIDC volumes have increased substantially (Figure 6). This shows a clear market demand for short-term trading opportunities across borders.

On 28 May 2024, the TSOs of the Core Capacity Calculation Region[9] commissioned the first flow-based cross-border capacity calculation for the intraday time frame (IDCC). The 16 Core TSOs and respective Regional Coordination Centres are now able to recalculate the available cross-border transmission capacity based on updated forecasts after the single day-ahead market (SDAC). This makes optimisation of cross-border capacity even more efficient, as calculations are moved up closer to real time, thus reflecting market developments from up to one day before the day of trading.

The intraday auctions consist of three IDCC processes:

- IDCC(a): Capacities that are not used in the day-ahead market ("day-ahead leftovers") are offered to the intraday market at 3 p.m. for all hours of the following day. This process went live in June 2024.
- IDCC(b): Capacities for the intraday market are recalculated and updated values are offered at 10 p.m. for all hours of the following day. This feature was implemented in May 2024.
- IDCC(c): Capacities are again recalculated for the last 18 hours of the day based on latest information and offered to the market at around 4.30 a.m. of the delivery day. This concept is not yet implemented but expected to go live in June 2025.

In the coming years, additional intraday capacity calculation processes will be put into operation, updating intraday capacities at 10 a.m. for IDA3 and 4 p.m. of the respective delivery day.

Providing sufficient cross-zonal transmission capacity is vital for a well-functioning, liquid intraday market and for integrating renewables into Europe's electricity system. Such capacity provision should nevertheless be subject to prudence to ensure system security, in particular close to real-time system operation. Extending the regulatory 70% minimum transmission capacity requirement to the intraday time frame currently applied to the day ahead (DA) is problematic in this context. In the DA time frame, such virtual capacities meeting the 70% requirement can be offered, assuming that at a later process stage remedial actions (RAs) will be available to resolve potential grid congestions. However, in the intraday time frame, coordinating such remedial actions becomes more challenging, because there is no equivalent coordination process once the intraday market closes. Additionally, the availability of RAs decreases close to real time due to shorter lead times. Furthermore, real-tme operation also needs to consider technical aspects such as reactive power control and voltage regulation when implementing RAs. Nevertheless, and based on the requirements of the Core Intraday Capacity Calculation Methodology (IDCCM), Core TSOs are investigating measures to further enhance the level of cross-zonal intraday capacity.

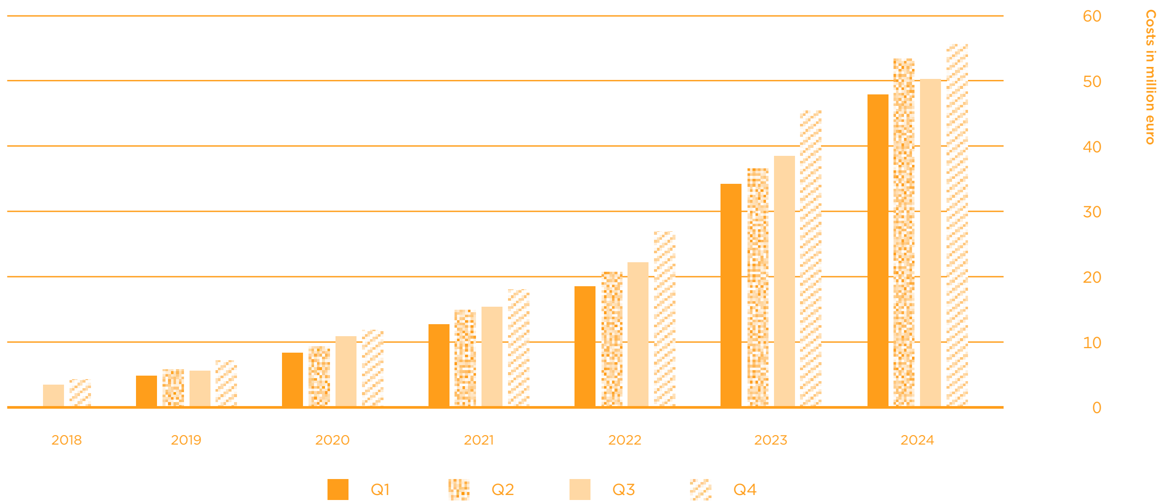


FIGURE 6 Intraday trades per quarter (in millions) in 2018–2024[10]

9 The Core Capacity Calculation Region consists of the bidding zone borders between Austria, Belgium, Croatia, the Czech Republic, France, Germany, Hungary, Luxembourg, the Netherlands, Poland, Romania, Slovakia and Slovenia.

10 Source: entsoe.eu/network_codes/cacm/implementation/sidc

DUNKELFLAUTE

Dunkelflaute is a term used in the energy sector to describe periods with minimal electricity generation from volatile renewable energy sources such as PV and both onshore and offshore wind power. Scientifically, there are varying definitions of *Dunkelflaute*. In our analysis, it is characterised by a drop in average electricity generation from these renewables to a maximum of 5% of their nominal capacity over a specified duration.

In 2024, political debate about *Dunkelflaute* became prominent in Germany, especially focusing on electricity prices in Germany and Europe. Media coverage often linked sporadically high electricity prices to challenges of the energy transition. Central to the debate was whether the structure of electricity production was driving increases in energy prices all over Europe. This was often attributed directly to German production with its reliance on PV and wind energy. However, reliable analysis on the causes and effects requires context: The short-term high-price phases had negligible effects on end consumers. As detailed in the previous chapter, the average wholesale electricity price (day-ahead) was 78 €/MWh in 2024, with prices exceeding 300 €/MWh for only 41 hours throughout the year. Excluding these hours, the average price would have been 77 €/MWh, a marginal decrease of 2%. During these high-price periods, Germany's electricity demand was met through substantial imports of up to 18 GW, while there were market and reserve capacities still available in Germany. Consequently, there was no significant lack of generation capacity from the perspective of the transmission network.

The year 2024 experienced an unprecedented *Dunkelflaute*, which lasted 263 hours, or nearly 11 days, marking the longest such period since 1982.

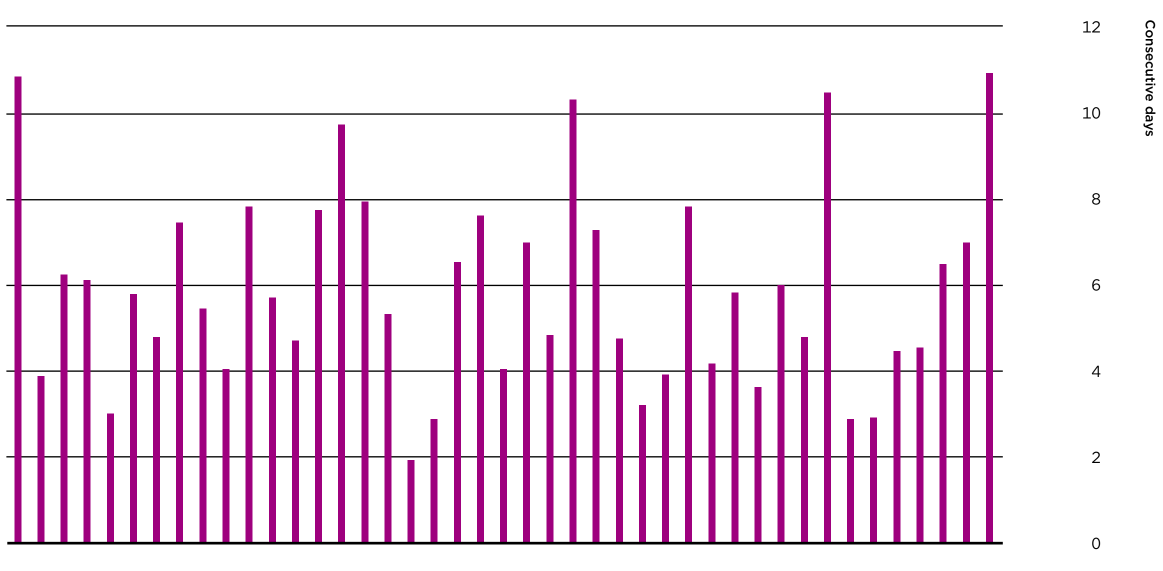


FIGURE 7 *Dunkelflaute* situations (RE generation <5% on average) for each year between 1982 and 2024[11]

11 Source: own analysis based on data of the European Ressource Adequacy Assessment (entsoe.eu/eraa/)

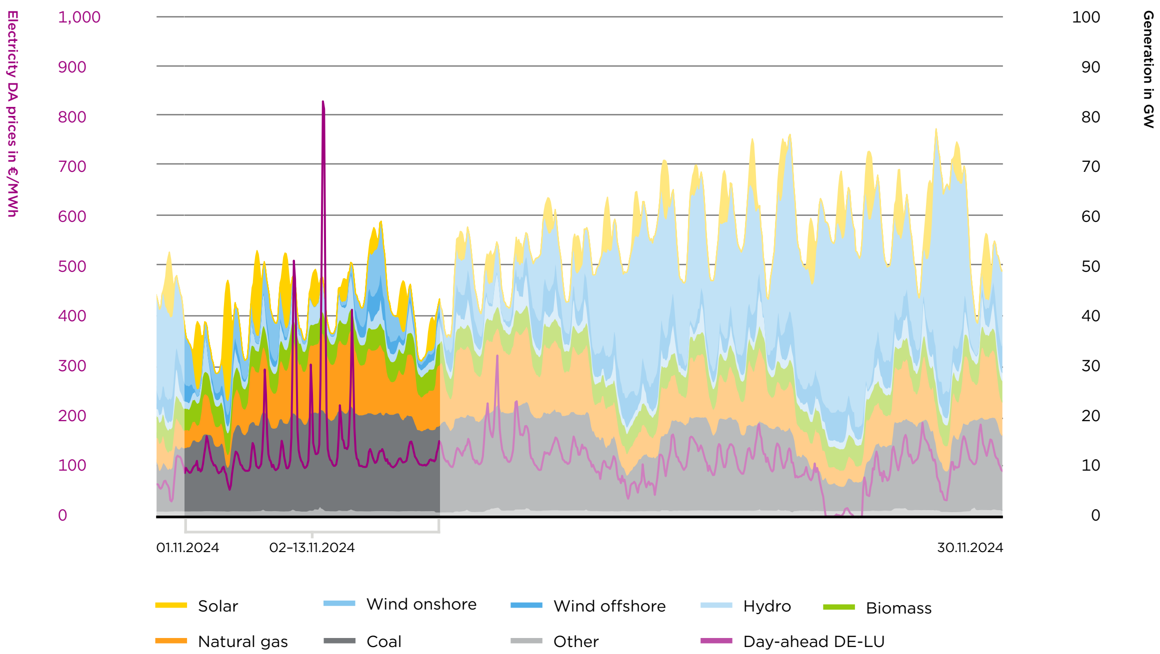


FIGURE 8 Power generation and DA prices in Germany for November 2024 with a focus on the *Dunkelflaute* period[12]

However, these brief high-price phases can be interpreted as early indicators of potential scarcity situations in the future due to current developments in the German generation structure. Security of supply analyses by German transmission system operators and ENTSO-E indicate that Germany could face supply security issues by the early 2030s if sufficient replacement generation capacities are not established and if coal power plants cease operations as currently planned.

Considering this development, we assessed the severity of the *Dunkelflaute* situation in Germany in 2024 and how often these phases occurred. Using weather data from the past 42 years, the theoretical renewable energy supply was simulated based on today's renewable energy capacity. This enabled a historical comparison of the 2024 weather situation. According to the predefined *Dunkelflaute* criteria (average maximum of 5% nominal capacity from PV and wind for a minimum of 24 hours), 2024 experienced an exceptionally long *Dunkelflaute*. It lasted 263 hours, or nearly 11 days, marking the longest such period since 1982. Historically, such long *Dunkelflaute* periods only occurred in 1982, 2006 and 2017 in Germany (see Figure 7) – when simulating the same renewable energy capacity.

This exceptionally long *Dunkelflaute* period in 2024 was not in December when extremely high prices occurred and on which the political discussion centred but between 2 and 13 November 2024 (see Figure 8). The first half of November was marked by very low renewable energy generation, while the second half of November saw significantly higher wind power generation, stabilising the monthly average renewable energy share at a low, but not critical level.

12 Source: transparency.entsoe.eu

Even though the conditions were unusually prolonged, the markets only registered some short-term price peaks in early November and prices remained well below the December 2024 highs. This was due partly to a warm spell in central Western Europe, which positively affected electricity demand due to less demand of electrified heating, especially in France, helping to moderate prices.

On 11 and 12 December, a shorter *Dunkelflaute* occurred (see Figure 9), but renewable generation was higher than in November which led to a less critical situation in terms of resource adequacy. Due to increased electricity demand, driven by colder temperatures and low plant availability, prices were higher than in November. Due to the unscheduled outages of power plants, *Bundesnetzagentur* (the German regulatory authority) announced investigations of the market behaviour of generators. The results are yet to be published at the date of writing and should offer additional insight into the supply situation in the high-price period in December.

Nevertheless, the analysis shows that the grid and market should be prepared for low renewable generation over a period of approximately ten days. There may be similarly long *Dunkelflaute* periods in future and weather conditions may not always be as favourable as in November 2024, driving up demand and making imports less readily available.

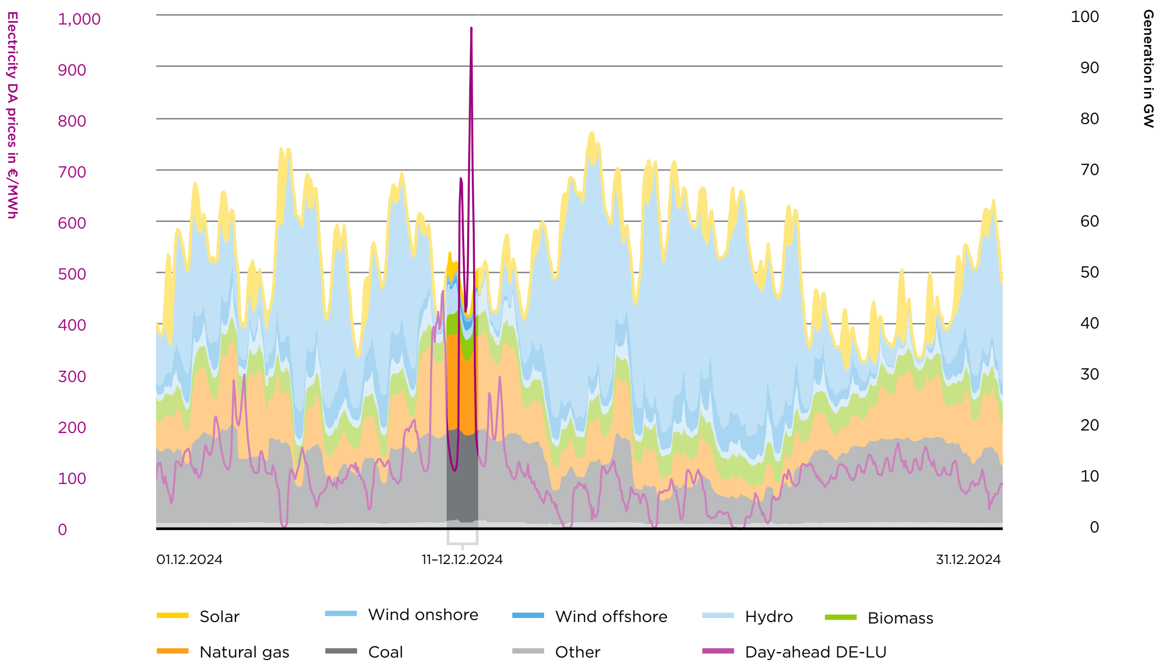


FIGURE 9 Power generation and DA prices in Germany for December 2024 with a focus on the *Dunkelflaute* period[13]

13 Source: transparency.entsoe.eu

EXCURSUS

PARTIAL DECOUPLING ON 25 JUNE

On 25 June, traders at the day-ahead market witnessed two co-existing day-ahead market clearing prices for the delivery date 26 June. This highly unusual situation was caused by a partial decoupling of European day-ahead electricity markets. As the bids of traders at the EPEX SPOT could not be matched across borders, traders needed to submit fallback bids in a highly uncertain market environment. This resulted in very unusual and extreme local prices at EPEX electricity exchange. Meanwhile, the bids of traders at other power exchanges were matched across borders with much lower prices for the same delivery period.

From time to time, the extreme prices of this extraordinary incident have been interpreted as proof of structural electricity supply shortages in Germany. But this interpretation does not sufficiently recognise the complexity of the European market coupling process. The extreme local prices from 25 June demonstrate how far the European market integration has progressed and how severely technical issues can affect the complex arrangement of an implicitly coupled electricity market. It seems unlikely that traders were able to adequately consider the sudden market disruption in their bids. In this special case, the extreme clearing prices are not the symptom of a structural electricity supply shortage but are simply mirroring the high uncertainty among market participants under these extraordinary circumstances.

SDAC parties immediately initiated an in-depth investigation of the events.[14]

14 Source: nemo-committee.eu/assets/files/single-day-ahead-market-coupling-(sdac)-report-on-the-partial-decoupling-incident-of-june-25-2024.pdf

HELLBRISE

About half of German PV producers receive fixed feed-in tariffs with no exposure to market prices and no incentive to reduce their production in case of negative prices.

The term *Hellbrise* has become a focal point in discussions about renewable energy, highlighting situations of abundant wind and PV production. These are characterised by the surplus of electricity often turning prices negative. While wind energy production can often be adjusted to mitigate this impact, solar energy production cannot be adjusted in the same way because of the large number of small, non-regulatable photovoltaic systems. The following analyses are therefore focused on situations with high PV feed-in.

In 2023 and 2024, slightly more than 30 GW of new PV capacity was installed in Germany. Thus, total installed PV capacity added up to approx. 99 GW by the end of 2024. About half of these PV systems receive a fixed feed-in tariff[15] and are therefore not exposed to price signals which would provide incentives to curtail production when prices turn negative. In 2024, we observed negative day-ahead prices in Germany during 457 hours. On many Sundays with high PV feed-in, these prices were significantly negative, reaching levels of up to –135 €/MWh. To understand what happens during the times of the so called *Hellbrise*, it is worth taking a closer look at individual days in 2024.

1 May 2024: Negative prices as a market peculiarity

On 1 May 2024, the day-ahead prices were significantly negative, with –120 €/MWh between 1 p.m. and 3 p.m. The intraday prices followed the patterns of the day-ahead prices. Nevertheless, no particular grid operation measures were required during the day: emergency reserves were not activated by the German TSOs and redispatch measures were at normal levels. This shows that negative prices as a “market peculiarity” do not necessarily indicate a market or grid problem. They can provide valuable market incentives for storage and flexibility.

15 Source: www.ise.fraunhofer.de/content/dam/ise/de/documents/publications/studies/2024-02-photovoltaik-und-batteriespeicherzubau-in-deutschland.pdf About 50% of newly installed PV capacity is below 30 kW per system, which by default are compensated via feed-in tariffs.

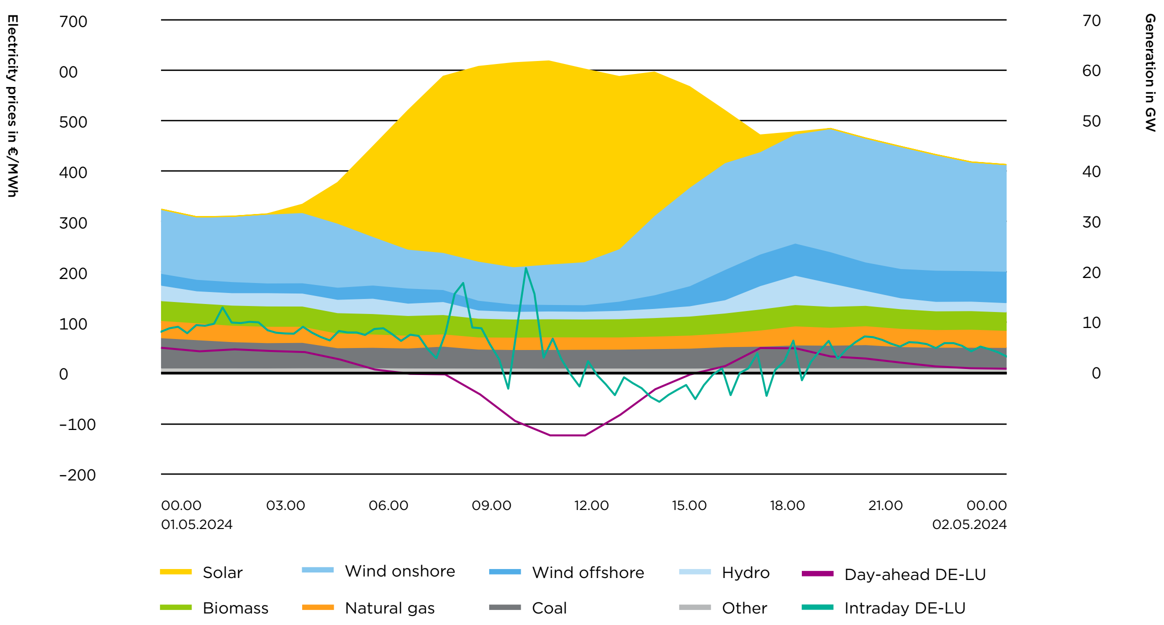


FIGURE 10 Power generation and DA and intraday prices in Germany on 1 May 2024[16]

7 April 2024: From market peculiarity to market problem

On 6 April, negative prices of up to –26.79 €/MWh were reached in the day-ahead market for the delivery day of 7 April. Closer to real time, further effects on the short-term availability of PV power impacted the intraday market. Firstly, a Saharan dust event led to uncertainties in PV production forecasts, resulting in a surplus of unforecasted energy which had to be sold on the intraday market. When considered alone, these fluctuations were still within the usual range and could be absorbed by the liquidity of the intraday markets.

However, the situation in Germany was exacerbated due to similar issues of a high PV feed-in and forecast uncertainties in neighbouring countries. Based on respective contracts for Mutual Emergency Assistance Service (MEAS), German TSOs assisted the TSOs in these countries. 50Hertz provided large quantities (up to 3 GW) of emergency reserve for the Polish TSO PSE. Throughout the same day, Amprion provided emergency reserves for the Belgian TSO ELIA (up to 614 MW), which was also sold via the German intraday market. These compounding factors led to a tense situation in the intraday market, culminating in trades being made at the technical minimum price of –9,999 €/MWh. Additionally, the high infeed led to significant automatic frequency restoration reserve (aFRR) activation. Subsequently, manual frequency restoration reserve (mFRR) of up to 396 MW was activated to balance excessive PV production.

16 Source: transparency.entsoe.eu; Intraday prices are volume-weighted average prices of all trades taking place during the trading session of a contract on relevant continuous market segment.

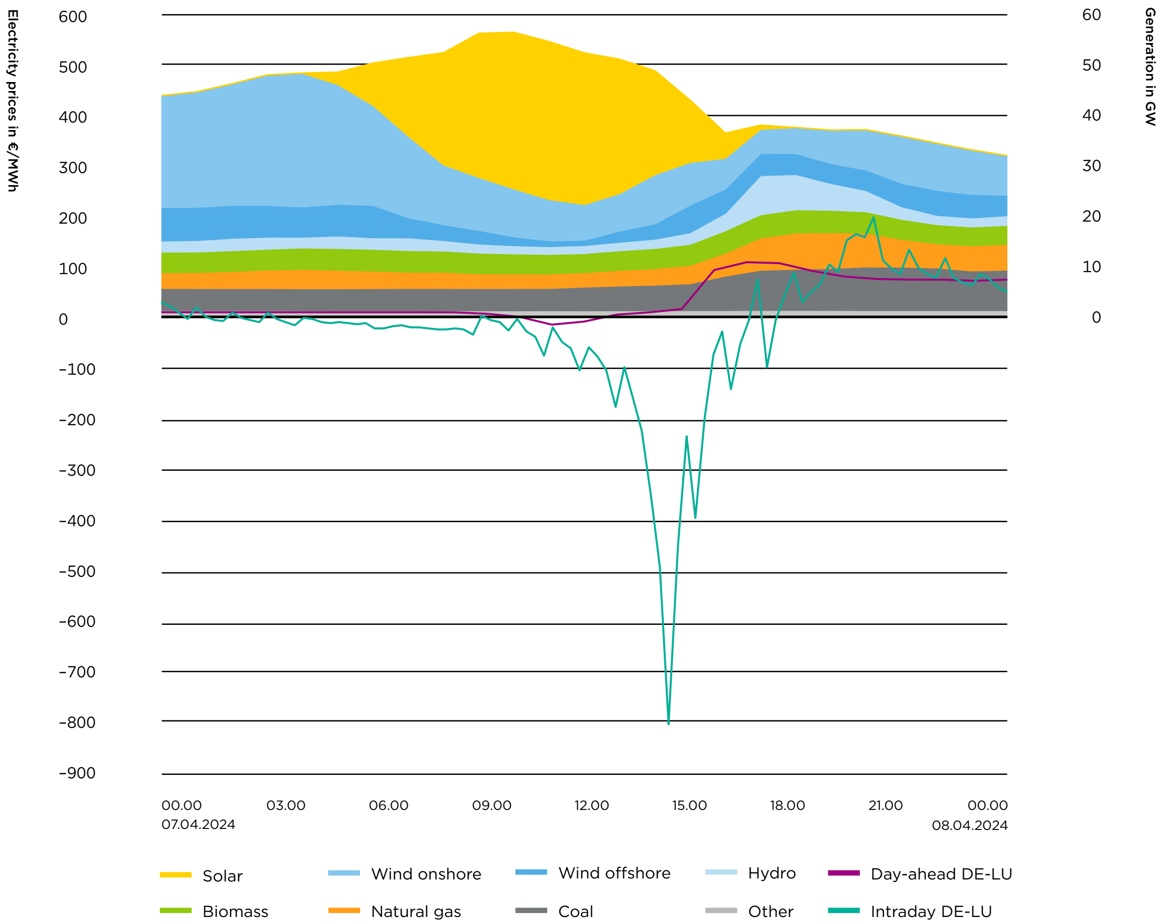


FIGURE 11 Power generation and DA and intraday prices in Germany on 7 April 2024[17]

In light of Germany's target of 215 GW of installed PV production and 145 GW of installed wind production capacity (incl. 30 GW offshore) in 2030, there is an increasing risk of generation considerably exceeding load, in particular during days when the load is small (weekends, holidays) and weather conditions are favourable for PV production. This will provide substantial challenges to network and system operation both in terms of congestion management and system balancing. Market flexibility, storage as well as flexibility of production for small-scale PV systems will be central to integrating this surplus production into the grid.

As a reaction to this issue, the German Bundestag passed the Solar Peak Act (*Solarspitzengesetz*), aiming to secure grid stability and prevent regional controlled blackouts by avoiding production peaks in solar power generation. Upon the enactment of this legislation in February 2025, newly commissioned PV will no longer receive feed-in tariffs when the market electricity price is negative. This reform is viewed as a late but positive step forward, as it encourages a genuine price response from energy producers, thereby enhancing the controllability of power generation during critical grid situations.

17 Source: transparency.entsoe.eu; Intraday prices are volume-weighted average prices of all trades taking place during the trading session of a contract on relevant continuous market segment.

PRICE CONVERGENCE AND MARKET-LIMITING GRID CONSTRAINTS

> The reduction of price differences and increasing price convergence[18] between bidding zones within a region is one of the main targets of market coupling. Sufficient cross-zonal transmission capacities are a crucial prerequisite for achieving this target.
>
> In the case of sufficient cross-zonal exchange capacities, prices between bidding zones converge. In the opposite case, if commercial exchanges are limited by transmission constraints, prices between the bidding zones diverge. The price convergence rate is therefore one indicator for the level of market integration in the Core region. However, since bidding zones are delineated by structural congestions, some level of price divergence is inherent to the zonal market by design. Besides the price convergence, which means that all trading requests of neighbouring bidding zones can be realised to allow the most economic dispatch of generation units to serve the demand of these bidding zones, the price spread is another important indicator of market coupling. In the case of price divergence, the remaining price spread reveals the need for further exchange capacities and the respective grid investments.

In 2024, the average price spread at the Core borders of the German bidding zone was 13 €/MWh (see Figure 12), compared to 8 €/MWh in 2023 and 30 €/MWh in 2022. Among the various borders, the German-French border exhibited the highest average price spread, exceeding 24 €/MWh. Similarly, the Polish borders also showed notable spreads, each surpassing 20 €/MWh.

> **Amprion continues to enhance the transmission grid and to improve cross-zonal trading capacities, to reap the full benefit of the integrated European electricity market.**

18 Full price convergence is reached if prices are equal across all bidding zones of a region.

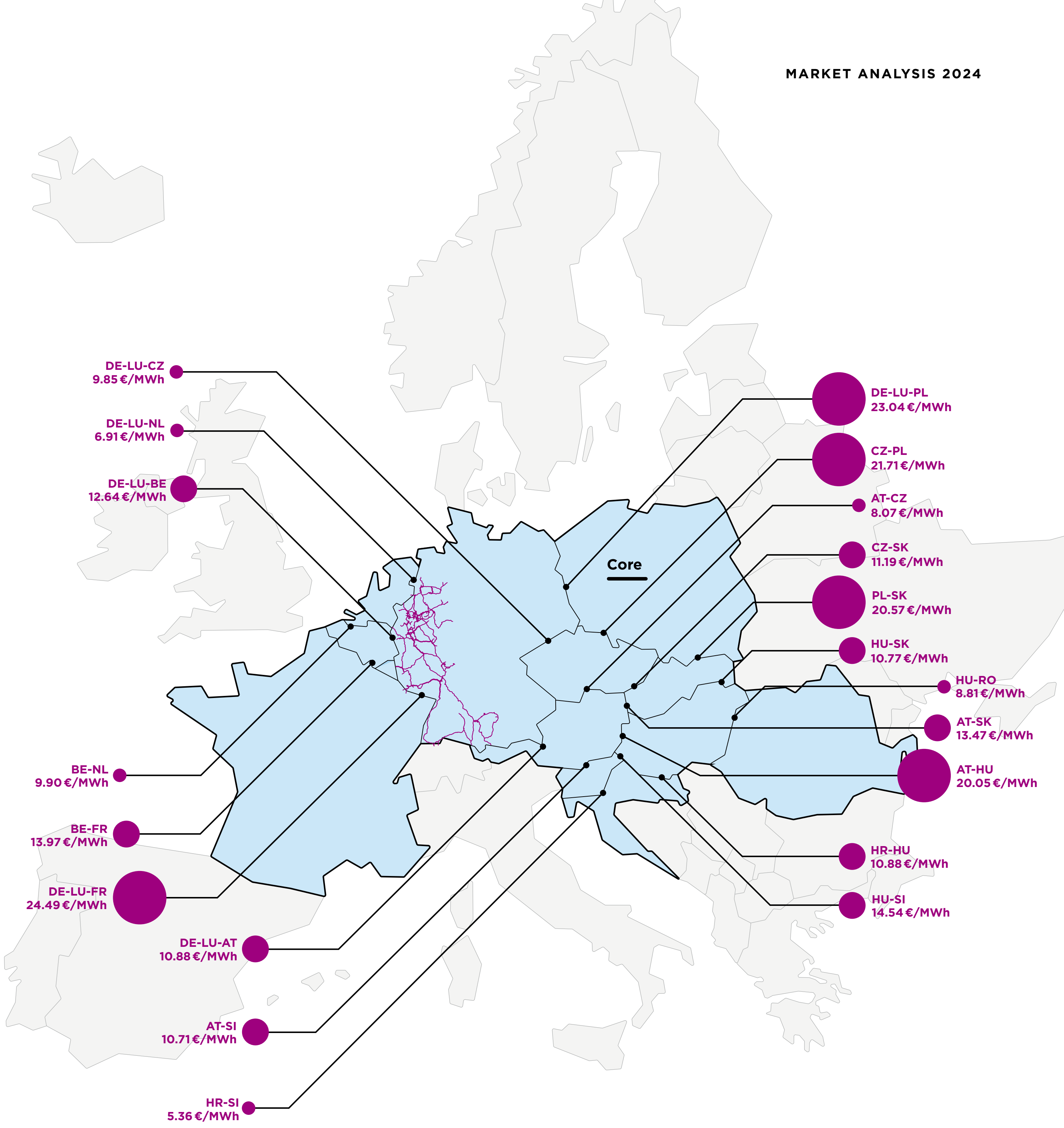


FIGURE 12 Average price spread in Core region in 2024 by border[19]

19 Source: transparency.entsoe.eu

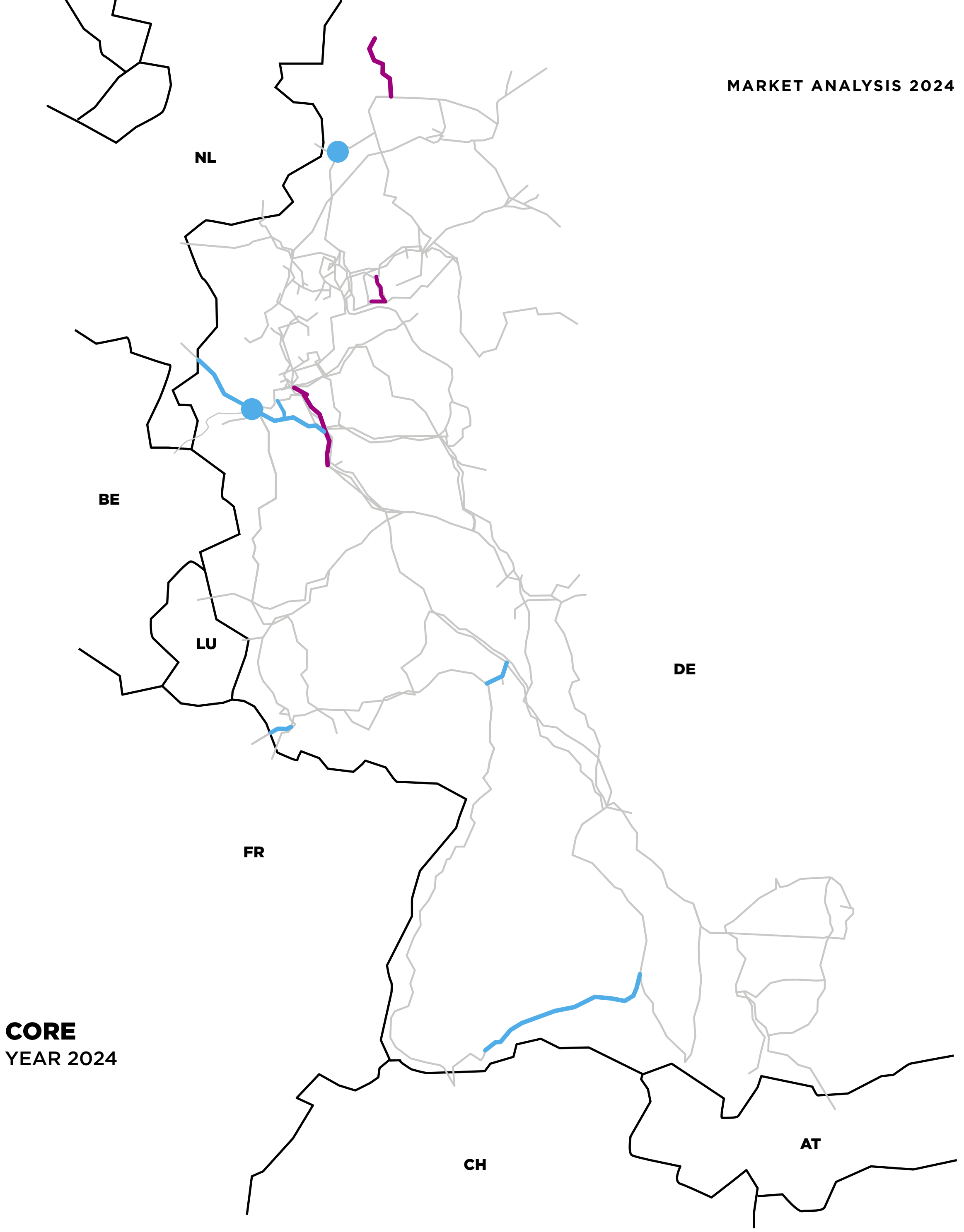
Price spreads are caused by trade restrictions on critical network elements within the grid of the Core region. These elements can restrict trade across borders, leading to price disparities between connected zones. Understanding these constraints is essential for addressing and potentially reducing price spreads in the future. Figure 13 provides insights into those critical network elements within the Amprion transmission grid which most frequently limited trades.

Looking at these most relevant critical network elements in Flow-Based Market Coupling in the Amprion grid, the overall picture has not changed fundamentally since 2022.

The most frequent trade limitations in the Amprion grid continue to occur on elements close to the French border (Vigy lines). Trade limitations become notably evident during electricity imports from France to Germany. The remaining network elements in Amprion's control area do not stand out with regard to the absolute frequency of trade limitations and when compared to network elements in the Core region.

Network elements in the Emsland region, i.e. the northern part of Amprion's control area, show the lowest average available trade margins for the year 2024; albeit with average margins still being close to 70% (hourly minimum requirement at 50.5% in 2024). Despite lower average margins, these network elements have not limited trade in the Core region even for a single hour.

To further reduce the frequency of trade limitations and maximise the benefits from the integrated European electricity market, Amprion is actively enhancing the transmission grid and improving cross-border trading capacities.



Top 10 critical network elements (CNEs) in 2024

With lowest offered trading margin for cross-zonal trade

Most often limiting trade (full use of potential trading margin)

FIGURE 13 Location of major (top 10) active critical network elements Flow-Based Market Coupling of Amprion as well as the ones with the lowest offered trading margin in 2024[20]

20 The general information about the critical network elements can also be downloaded via the Utility tool available via JAO, see utilitytool.jao.eu

GRID OPERATION ANALYSIS 2024

The generation of electricity causes electrical load flows. If such load flows exceed the technical limitations of network elements taking into account the n-1 criterion[21], the electricity generation pattern has to be changed. This process is called redispatching, where TSOs must reduce electricity generation at dedicated locations in the grid to alleviate the electricity flow on constrained network elements. To keep electricity generation and demand in balance, electricity generation has to be increased in other less constrained areas.

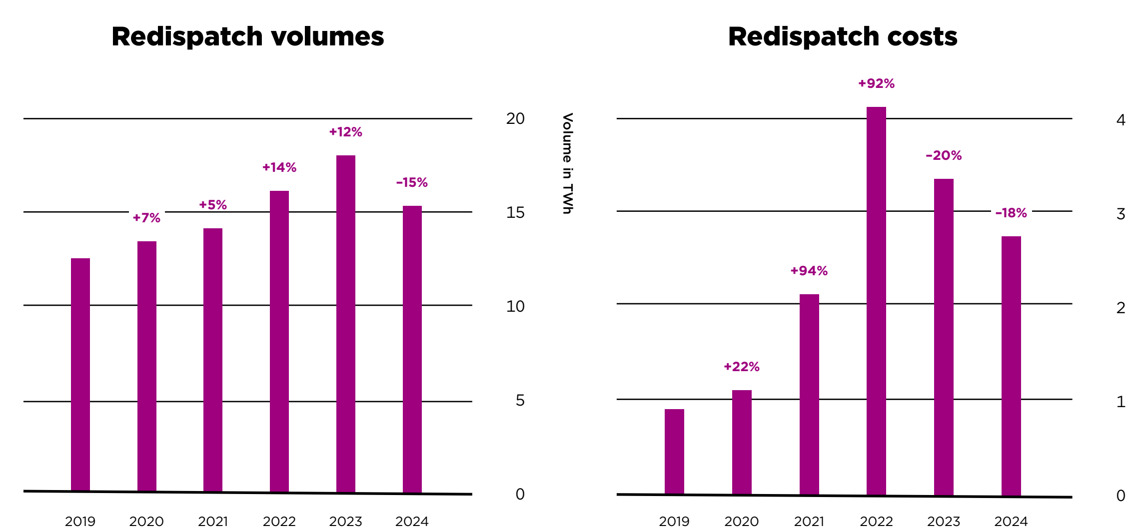


FIGURE 14 Total redispatch volumes and costs for Germany in 2019–2024[22]

In 2024, congestion management costs across Germany amounted to 2.7 billion €, which was below the previous year's level. Also, congestion management volumes decreased compared to 2023 (Figure 14).

21 N-1 criterion: Within our transmission grid, each node is connected to other nodes by overhead lines or cables. If an individual line or other equipment, such as a transformer, fails, the electricity can always be transmitted via an alternative route – without causing further disruption or the overloading of other equipment.

22 Illustration of the volume according to the definition of redispatch in line with the documented quantity. A redispatch is always instructed in a balanced manner, i.e. the source corresponds to the sink. The costs arise from both the source and the sink.

This development is due mainly to a major grid expansion project, the Energy Line Expansion Act – Project 2 (“EnLAG 2”), which was successfully completed in the end of 2023 and was, for the first time, operational for a whole year in 2024. The 94 km-long line from Ganderkesee to Wehrendorf stretches across two German federal states, Lower Saxony and North Rhine-Westphalia, and was commissioned in cooperation between TenneT Germany and Amprion. This project significantly relieves Germany’s biggest congestion in the Emsland region. As a result, more than half a billion euros of congestion management costs were saved. In addition, the onshore wind feed-in was significantly lower than in the year 2023, even though the installed capacity slightly increased. This effect also positively impacted congestion management in 2024.

The 94 km-long line from Ganderkesee to Wehrendorf significantly relieved Germany’s biggest congestion in the Emsland region.

Additionally, nuclear power plants in France produced more energy due to higher availability (Figure 15) which led to a reduction in the transit and export-related grid load. For the congestion management costs, prices for electricity, hard coal and natural gas were slightly lower in 2024 than one year before, especially in the first quarter of 2024. This drop in prices additionally reduced the congestion management costs besides the overall lower demand for congestion management.

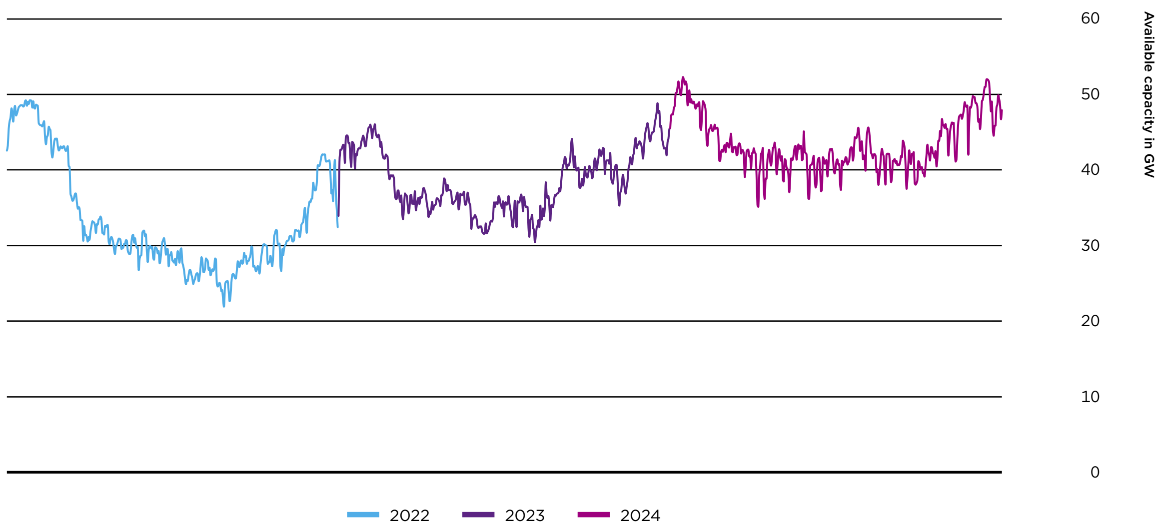


FIGURE 15 Availability of nuclear power plants in France in 2022–2024[23]

23 Source: transparency.entsoe.eu

FUTURE DEVELOPMENTS: BIDDING ZONES

BIDDING ZONE REVIEW

After a multi-year process, the European TSOs published the Bidding Zone Review Study[24] on 28 April. The study's aim is to compare different split scenarios with the current bidding zone configuration and to determine the most efficient configuration based on a large-scale analysis of 22 evaluation criteria. The Bidding Zone Review Study was initiated in 2019 with the target year of 2025.

The Agency for the Cooperation of Energy Regulators (ACER) determined the configurations to be assessed as well as the methodology[25] to be used for this assessment. This led to a strict assessment process and left limited room for the consideration of expert assessments as well as specific aspects considered relevant by the European TSOs.

The split scenarios analysed focus mainly on the German bidding zone. Out of the nine alternative configurations, six configurations include this country. The individual split configurations for Germany are shown in Figure 16.

There is an ongoing academic and political debate on the reasons for a bidding zone split. The main goal of splitting or reconfiguring a bidding zone in the electricity market would be to better reflect the physical reality of the electricity grid in market coupling and therefore reduce redispatch and the resulting costs. However, this is only one of many aspects to take into account – several considerations as described in the Bidding Zone Review Study should be carefully considered before deciding upon a potential bidding zone reconfiguration. In general, a bidding zone split is a measure to manage congestions. However, for solving congestions, to integrate the large amount of renewable electricity generation and to ensure a reliable energy provision for new demand, efficient grid expansion is essential and therefore a no-regrets measure.

The most effective bidding zone configuration evaluated results in an estimated positive monetised benefit of 339 million € for the target year 2025, which is less than 1% of the simulated system costs in the Central Europe region.

24 Source: www.entsoe.eu/network_codes/bzr/

25 Source: acer.europa.eu/electricity/market-rules/capacity-allocation-and-congestion-management/bidding-zone-review

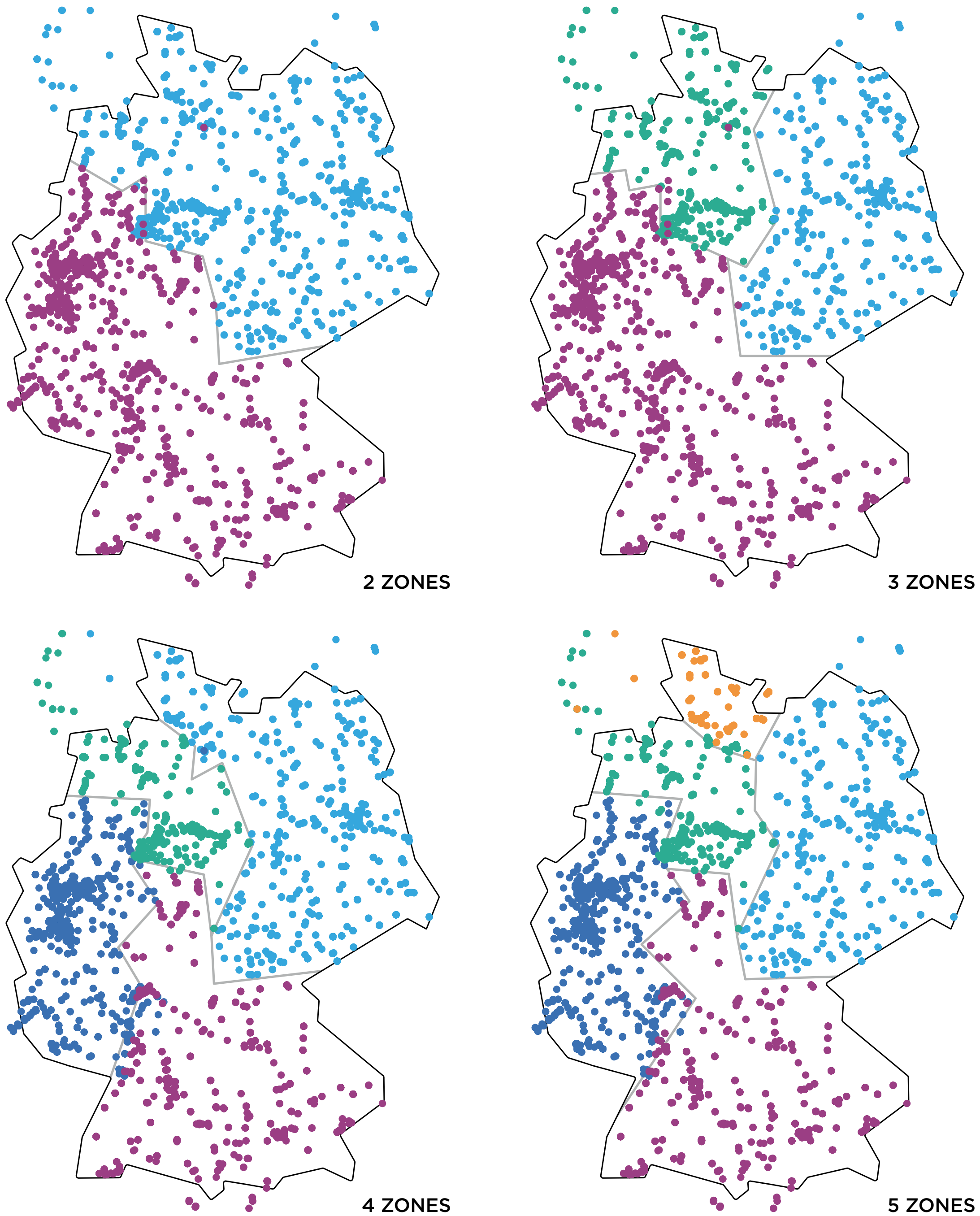


FIGURE 16 Individual split configurations for configurations for Germany assessed in the Bidding Zone Review Study[26]

26 Source: www.entsoe.eu/network_codes/bzr/

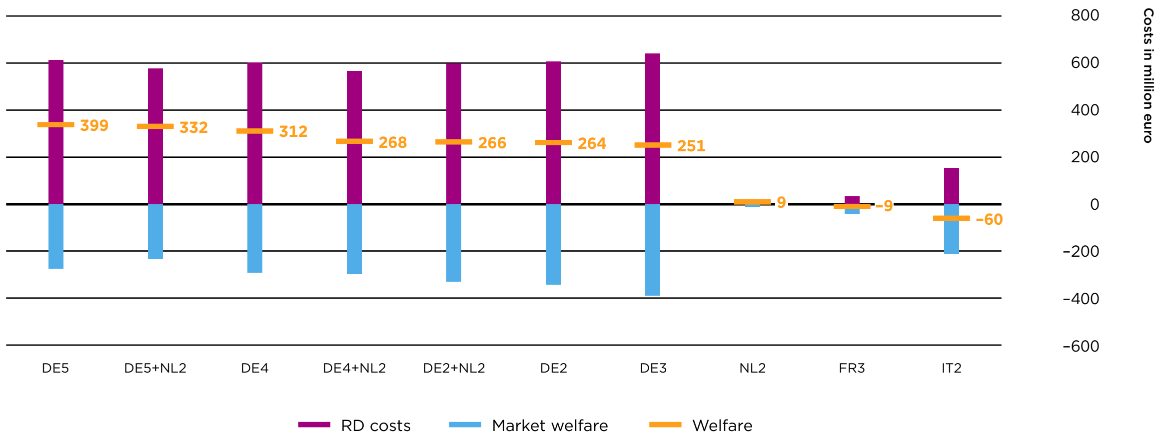


FIGURE 17 Average change in socio-economic welfare over all three simulated climate years for the 2025 target year compared to the status quo configuration[27]

The main indicator of the Bidding Zone Review Study according to ACER's methodology is the impact of an alternative configuration on the subject of socio-economic welfare. The calculated change in socio-economic welfare results from a model-based assessment and is displayed in Figure 17.

Based on the analysis performed according to the legal requirements, the European TSOs have formulated a proposal to the member states for either keeping or adjusting the current bidding zone configuration.[28] The proposal includes the following aspects:

- The results of the Bidding Zone Review Study indicate that the configuration with the highest positive monetised benefit compared to the status quo would be the split of Germany into five bidding zones (when strictly applying the Bidding Zone Review Methodology and data requirements defined by ACER without any additional considerations), displayed as DE5 in Figure 17. This configuration results in an estimated positive monetised benefit of 339 million € for the target year 2025, which is the simulated sum of positive and negative welfare changes in different countries. This rather low increase of overall welfare is less than 1% of the simulated system costs in the Central Europe region.
- Based on the estimated transition costs as part of the Bidding Zone Review Study, the minimum lifetime for the German split configurations is four to nine years. If a potential bidding zone reconfiguration became operational as of around 2030 considering several years of implementation time, the break-even point would be reached by the mid to late 2030s.

27 Source: www.entsoe.eu/network_codes/bzr/, The scenarios labels in the graph consist of the bidding zone and the number of bidding zones it is split into.

28 The member state decision-making is a two-step process pursuant to Articles 14(7) and 14(8) of Regulation (EU) 2019/943 on the internal market in electricity:
1) the member states with identified structural congestion (in our case Germany and Luxembourg) shall decide either to establish national or multinational action plans or to review and amend its bidding zone configuration.
2) for those member states that have opted to amend the bidding zone configuration, the relevant member states shall reach a unanimous decision. In the event that the relevant member states fail to reach a unanimous decision, they shall immediately notify the European Commission thereof. As a measure of last resort, the European Commission after consulting ACER shall adopt a decision.

- By following the given methodology, the Bidding Zone Review Study neglects important aspects and therefore should not be seen in isolation but rather in combination with certain considerations, which are key for the decision by the relevant member states on the future bidding zone configuration.

- An example for such neglected but important aspects are distributional effects of a potential bidding zone split. They will lead to different electricity prices and hence costs for certain groups of consumers. While several consumers across Europe may benefit from lower electricity prices, at the other end it should be ensured that higher electricity prices for other consumers do not have too strong overarching negative economic implications. For example, higher prices for price-sensitive industrial customers should not result in closures of industrial production. While for certain countries the overall impact of a split might balance out, others are likely to experience predominantly negative effects on their industry without any clearly identifiable benefits. Another example not examined in the study is the effect of a bidding zone split based on the need for additional subsidies for renewable electricity. This aspect is further specified in the section below.

All considerations mentioned in the TSOs' proposal on the bidding zone configuration can be found in the executive summary or chapter 6.7 of the Bidding Zone Review Study.

In conclusion, the Bidding Zone Review Study gives a high-level overview of important impacts alternative split configurations would bring. The analyses should, however, always be carefully evaluated against the background of further qualitative considerations.

IMPACT OF A BIDDING ZONE SPLIT ON GRID TARIFFS AND RENEWABLE FINANCING

In the current debates on the split of the German bidding zone, often only the effects on the electricity prices and dispatch or congestion management are discussed. Other important aspects, such as the influence of bidding zone splitting on grid tariffs, particularly in the low-voltage segment, and the need to support renewable energies, are often not considered[29].

The split of the German bidding zone into two could have a significant impact on renewable energies, particularly PV and wind, affecting both the market shares of the technologies and, as a result, their market values. This is due to regional differences in the supply of primary energy (wind energy more in the north and PV energy in the south). A bidding zone split would lead to an increase in the market share of these technologies in the respective region. This increased market share and, at the same time, a lower (split) supply of flexible generation and load would increase price volatility. Regions with a high share of wind energy could face an excess of energy production when the wind is strong, leading to low electricity prices and a lower regional market value for wind energy. Similarly, high PV infeed regions could face lower market values for PV energy. The described effects are shown schematically in Figure 18.

In case of a German bidding zone split, the additional subsidies for renewable energies would exceed the savings in redispatch.

29 Amprion conducted an analysis on both aspects: iewt2025.eeg.tuwien.ac.at/download/contribution/fullpaper/152/152_fullpaper_20250218_090146.pdf

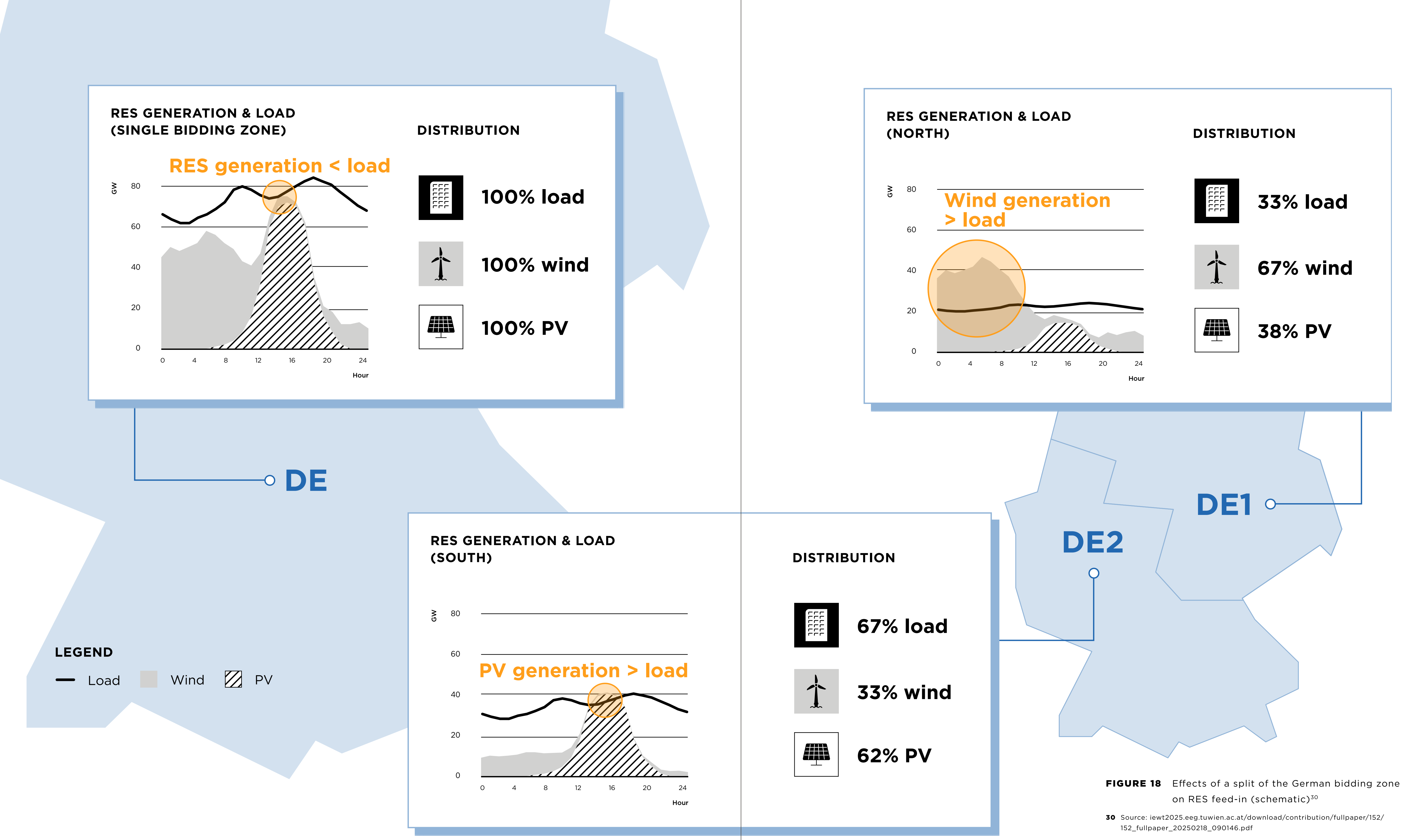


FIGURE 18 Effects of a split of the German bidding zone on RES feed-in (schematic)[30]

30 Source: iewt2025.eeg.tuwien.ac.at/download/contribution/fullpaper/152/152_fullpaper_20250218_090146.pdf

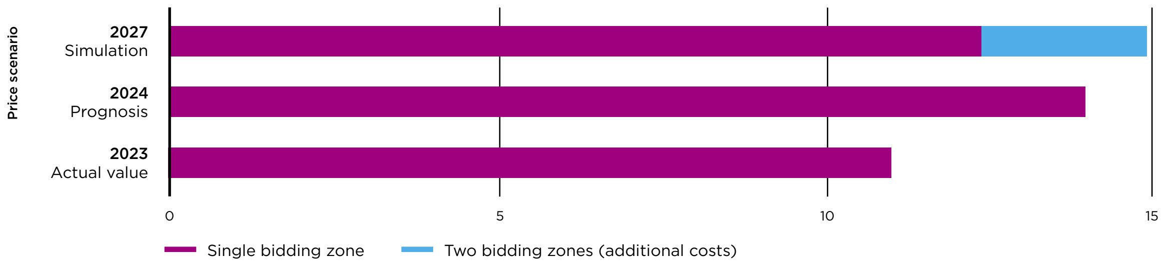


FIGURE 19 Subsidy needs for PV and wind and additional costs due to bidding zone split[31]

To identify the additional subsidies for PV and wind in case of a bidding zone split, our analysis determined renewable electricity market values and individual subsidies based on an Amprion-internal market and redispatch simulation. The results are evaluated for the status quo as well as for a bidding zone split for the target year 2027. The additional expenses for subsidies are around 2.5 billion € per year higher than the subsidies for a single German bidding zone (see Figure 19). Compared to a simulated reduction of congestion management costs for 2027 of around 2 billion €, the additional subsidies for PV and wind energy are likely to exceed the savings in redispatch in Germany. In addition, the expenditure for subsidies in the northern zone is around 4 billion € higher than in the southern zone.

A bidding zone split would decrease congestion management costs for customers at the low-voltage level, leading to savings in the grid tariffs. The analysis indicates that the southern zone would tend to benefit more (southern grid tariffs: –7.6 €/MWh) than the northern (northern grid tariffs: –5.9 €/MWh) (see Figure 20). This is due to structural differences in the upstream grid costs of the distribution system operators (DSOs), affecting the grid tariffs. DSOs in the northern zone tend to have higher generation (primarily renewable energy) in their own grid and therefore a lower share of upstream grid tariffs. As a result, end customers there benefit less from relief in the TSO grid tariffs. This effect is of the same magnitude as the electricity price differences (southern electricity prices: +0.4 ct/kWh and northern electricity prices: –1.0 ct/kWh).

In terms of distributional effects, the northern zone would benefit more from lower electricity prices whereas the southern zone would benefit more from lower grid tariffs. As for the subsidies of renewable energies, the split would lead to significantly higher costs caused in the northern zone.

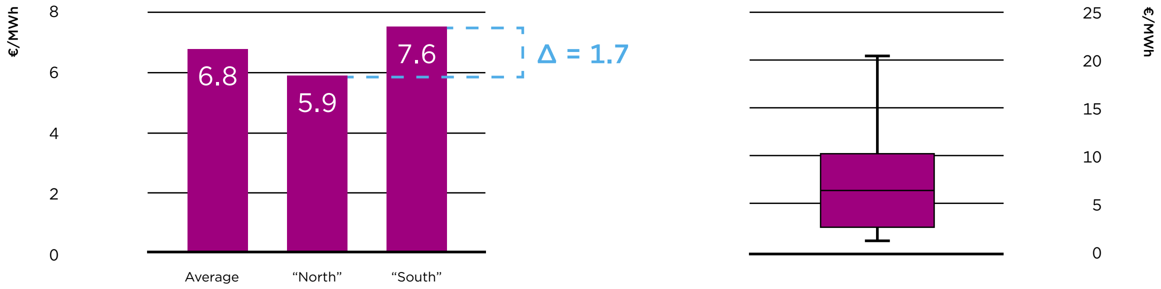


FIGURE 20 Comparison of grid tariff savings due to a bidding zone split: weighted savings for household customers (grid tariffs) (left) and distribution of savings for household customers by changes in grid tariffs (right)[31]

31 Source: iewt2025.eeg.tuwien.ac.at/download/contribution/fullpaper/152/152_fullpaper_20250218_090146.pdf

OUTLOOK

The changing structure of the energy system shows progress in the energy transition despite the existing challenges in transmission system operations such as congestion. Redispatch costs in Germany have recently been falling due to the ongoing grid expansion and its positive effects on integrating renewable energies and facilitating the European market. Also dropping commodity prices play a significant role in influencing redispatch costs. In the long-term, continued grid expansion will reduce redispatch costs. However, in the short to medium term, factors such as market developments and increased renewable electricity infeed can temporarily overshadow the benefits of grid expansion. Additionally, the impending increase of the minimum transmission capacity requirement to 70% by the end of 2025 is likely to elevate redispatch costs until the grid is sufficiently expanded.

Parallel to the progressing energy transition, the discussion about splitting the German bidding zone continues. Despite all methodological limitations, the Bidding Zone Review Study provides an appropriate framework to advance this discussion at the European level. However, the results of the current review can only be one aspect in the complex discussion about the future configuration of the European energy market.

Dunkelflaute situations and the challenges of *Hellbrise* will persist in 2025. Although several important regulatory measures were implemented in 2024, including the requirement for the adjustability of smaller PV systems and lowering the threshold for mandatory direct marketing, *Hellbrise* issues have not been fully resolved. The implemented legislative adjustments can mitigate market problems and can influence the expansion of storage technologies but are not yet sufficient to completely address the issues, namely the existing installations and smaller PV systems that continue to put strain on the distribution grids and pose a challenge for system operations.

To manage *Dunkelflaute* situations, the introduction of a capacity mechanism is being discussed in Germany and other European countries. For Germany, the implementation of local investment incentives and a consideration of ancillary service needs would be a valuable element of a future conceptual capacity mechanism design.

Legislation needs to constantly review regulation to accompany the arising challenges of the progressing energy transition.

LIST OF ABBREVIATIONS

ACER	Agency for the Cooperation of Energy Regulators
aFFR	Automatic frequency restoration reserve
DA	Day-Ahead
DSO	Distribution System Operator
EnLAG	Energy Line Expansion Act
EPEX	European Power Exchange
EU	European Union
IDA	Intraday Auction
IDCC	Intraday Capacity Calculation
IDCCM	Core Intraday Capacity Calculation Methodology
mFRR	Manual Frequency Restoration Reserve
PV	Photovoltaic
RA	Remedial Action
RE	Renewable Energy
SDAC	Single Day-Ahead Coupling
SIDC	Single Intraday Coupling
TSO	Transmission System Operator

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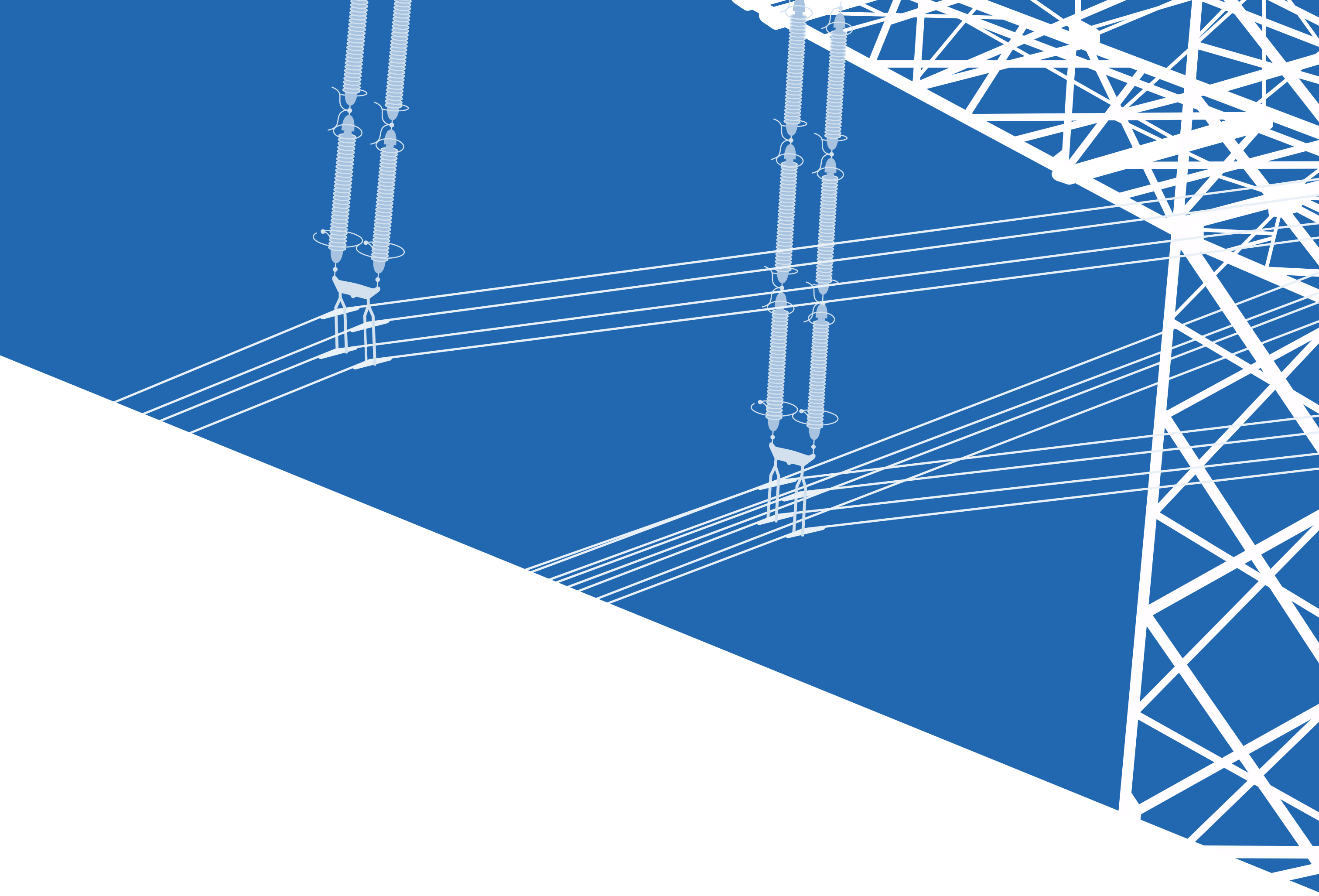

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