MARKET REPORT

2022/23

How the energy crisis affects the transmission grid
and international trading

The Amprion annual market report analyses the developments of the European electricity market and the effects on the underlying transmission grid. This year's report comes at a turbulent time for the European energy markets. Several effects of these turbulences on electricity markets, e.g. prices for gas and electricity which reached all-time highs in 2022, electricity exchanges across Europe and some exceptional market interventions, are key subjects of this report.

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/

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EXECUTIVE SUMMARY

Prices for gas and electricity reaching all-time highs in combination with unexpected unavailability of nuclear and hydro power plants in Europe, have led to an exceptional situation on energy markets in 2022.

Caused by the war on Ukraine, European energy markets have experienced turbulent times. Average electricity prices climbed from around 30 €/MWh in 2020 and 97 €/MWh in 2021 to 236 €/MWh in 2022. Power plant and transmission system operators (TSOs) all over Europe have contributed significantly to weakening the impact of these turbulences on the energy markets. Amprion and other TSOs have been supporting international trade, for example by increasing the offered grid capacity for cross-zonal trade from 31% to 40.8% before the originally envisaged timelines. This has enabled exports to France, where several nuclear power generation capacities have been out of operation. In overall terms, German net electricity exports have increased by around 20% compared to 2021. Furthermore, the EU is even accentuating its climate goals by raising the targeted share of renewable energies in the EU energy mix up to 45% in 2030. All in all, 2022 was the third exceptional year in a row after the Covid pandemic in 2020 and the first turbulences on the energy markets in 2021. Last year's events have revealed the importance of setting the course towards a robust and sustainable power system. This requires in particular the establishment of appropriate boundary conditions, such as a future-proof investment framework and market design.

Substantial investments in the transmission grid are required in the next two decades. Offshore wind power in combination with an interconnected grid in the North Sea will significantly push renewable energy generation in Europe.

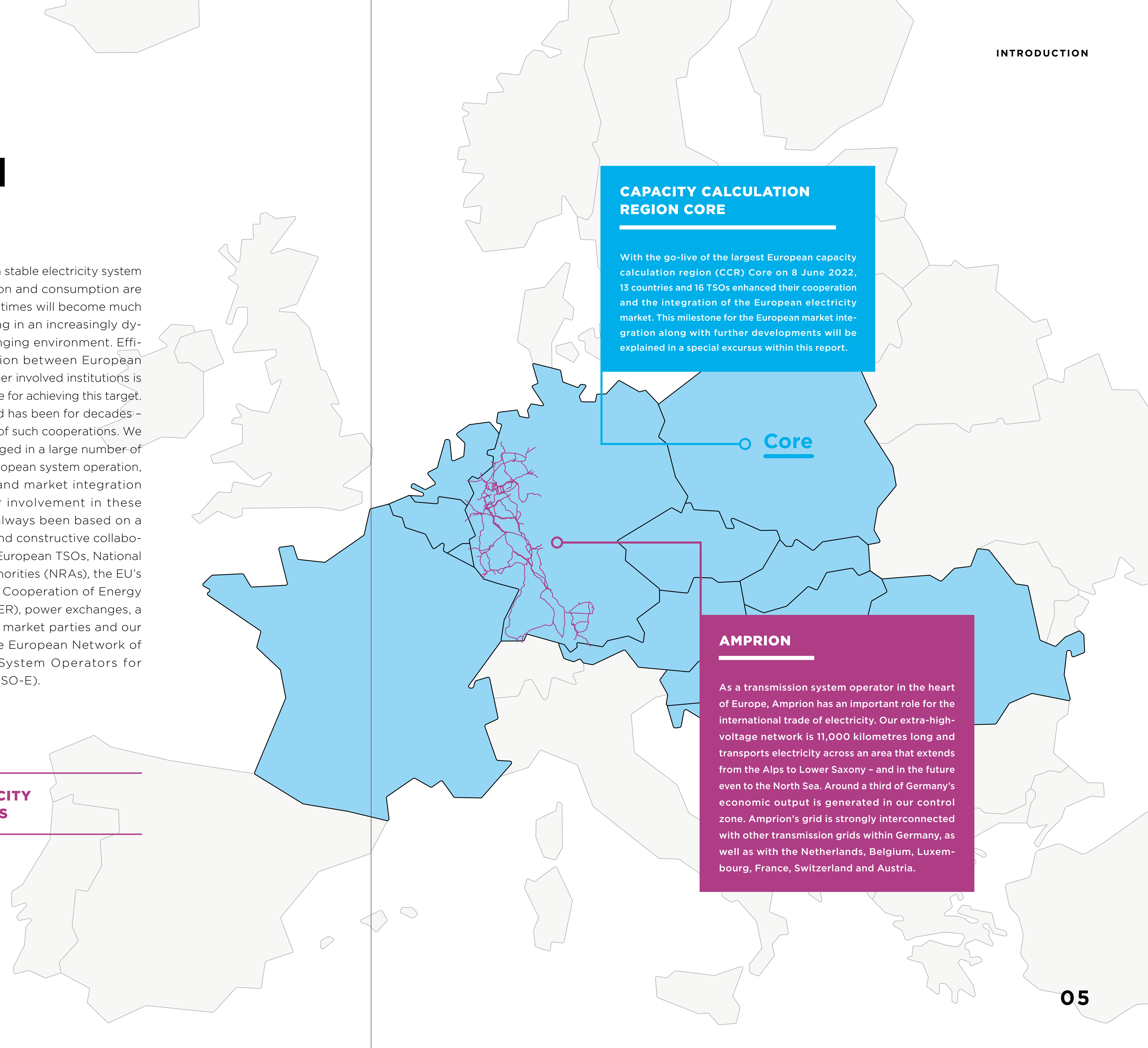
Besides strengthening the market, the European transmission grid expansion is essential in order to enable the further integration of renewable energies. For that reason, Amprion is extending its grid infrastructure by more than 2,500 kilometres in the next ten years. By the end of 2022, 616 kilometres of the transmission lines based on national planning processes had already been finished. Over the next five years, Amprion is planning more than 22 billion Euro of further grid investments. One additional pillar of the long-term investments is the stepwise development of an interconnected offshore grid in cooperation with international partners, which was initialised in 2022 with the Esbjerg Declaration "on the North Sea as the green power plant of Europe". Here it is important that the offshore energy is well connected to the load centres and industrial customers which means a close coordination of onshore and offshore grid expansion.

Grid expansion and an efficient market design is key for the future European energy transition. Now more than ever, a market design promoting the expansion of renewable and new back-up capacities for Germany and Europe is needed to become CO2-neutral, reliable and more independent from energy imports.

INTRODUCTION

The European Green Deal of 2019 has set the course of the European energy transition. Its major goal is a 55% reduction of greenhouse gas emissions by 2030 compared to 1990. In 2022, the European Commission (EC) presented a plan (REPowerEU) to even accentuate their climate goals by raising the targeted share of renewable energies in the EU energy mix up to 45% in 2030. As the transmission grid is the key enabler for the further integration of renewable energies and the interconnection of markets, transmission system operators (TSOs) play an important role in the entire energy transition. On a national level, the German energy system is undergoing an unprecedented transformation. Electricity production from nuclear energy has just been phased out in the middle of April 2023 and coal power generation is intended to be phased out by 2030. At the same time, an increasing share of renewable energies of up to 80% is envisaged. Ensuring a stable electricity system where generation and consumption are in balance at all times will become much more demanding in an increasingly dynamic and changing environment. Efficient cooperation between European TSOs and all other involved institutions is a key prerequisite for achieving this target. Amprion is – and has been for decades – an integral part of such cooperations. We have been engaged in a large number of regional and European system operation, grid planning and market integration initiatives. Our involvement in these initiatives has always been based on a close, trustful and constructive collaboration with the European TSOs, National Regulatory Authorities (NRAs), the EU's Agency for the Cooperation of Energy Regulators (ACER), power exchanges, a vast number of market parties and our association, the European Network of Transmission System Operators for Electricity (ENTSO-E).

AMPRION CONNECTS ELECTRICITY MARKETS ACROSS BORDERS



CAPACITY CALCULATION REGION CORE

With the go-live of the largest European capacity calculation region (CCR) Core on 8 June 2022, 13 countries and 16 TSOs enhanced their cooperation and the integration of the European electricity market. This milestone for the European market integration along with further developments will be explained in a special excursus within this report.

AMPRION

As a transmission system operator in the heart of Europe, Amprion has an important role for the international trade of electricity. Our extra-high-voltage network is 11,000 kilometres long and transports electricity across an area that extends from the Alps to Lower Saxony – and in the future even to the North Sea. Around a third of Germany's economic output is generated in our control zone. Amprion's grid is strongly interconnected with other transmission grids within Germany, as well as with the Netherlands, Belgium, Luxembourg, France, Switzerland and Austria.

HIGH ENERGY PRICES AND MARKET INTERVENTIONS

In 2022, the electricity market has been extremely influenced by high gas prices due to the tense political situation in Europe stemming from the Russian war on Ukraine. This has led to unprecedented measures of the European Commission to intervene in the gas and electricity market regulation.

On 18 October 2022, the European Commission published its seventh report on the state of the energy union[1]. It investigates the challenges of the European energy sector due to energy insecurity and price volatility as well as the adopted countermeasures. Major achievements of these measures have been a reduction of Russia's share of pipeline gas imports to the EU from 41% in 2021 to only 9% in September 2022. Simultaneously, the share of liquefied natural gas (LNG) imports has been raised up to 32%. The fast and ongoing expansion of LNG terminals in Germany will contribute to further increasing this share.

However, all these measures could not prevent a substantial increase of gas prices. Due to the interdependencies between the gas and electricity price[2], the electricity wholesale market price increased to an all-time high in 2022. The average day-ahead (DA) price in Germany reached about 236 €/MWh in 2022 compared to 30 €/MWh in 2020 (cf. Figure 1). This corresponds to an increase of nearly 700% during these two years.

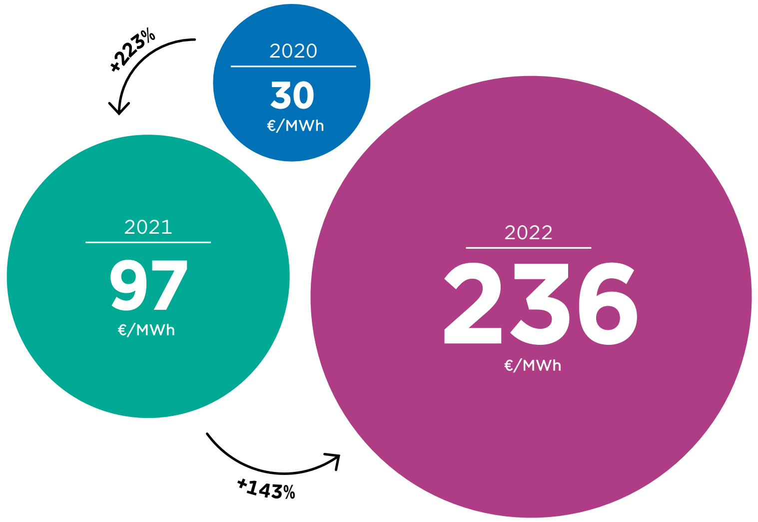


FIGURE 1 Development of average day-ahead (DA) prices in Germany[3]

1 Source: energy.ec.europa.eu/topics/energy-strategy/energy-union/seventh-report-state-energy-union_en
2 Due to the Merit Order Model, gas-fired power plants are most often decisive for the electricity price.
3 Source: transparency.entsoe.eu

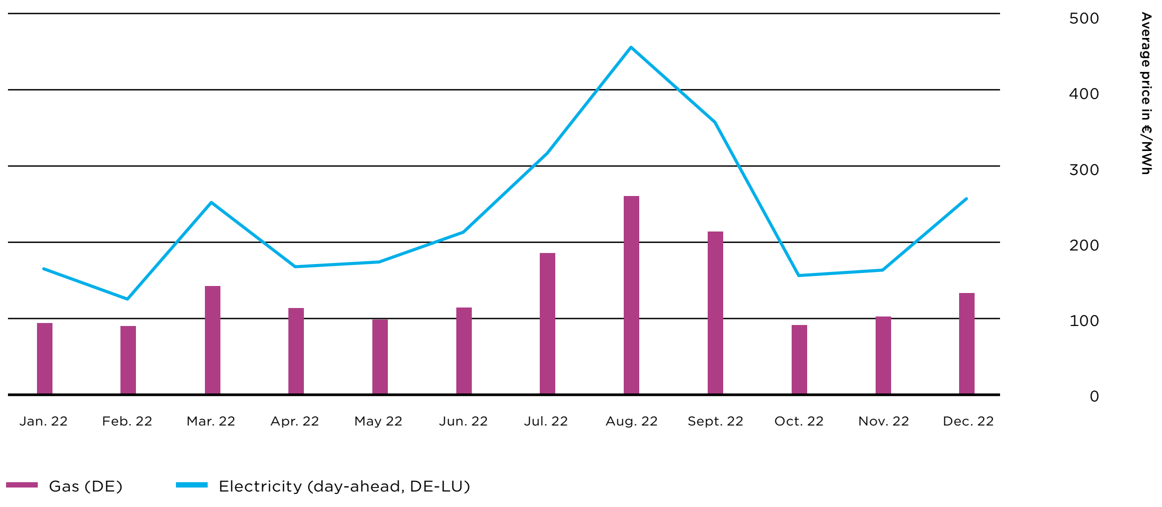


FIGURE 2 Development of electricity and gas prices in 2022 by month[4]

The price development correlates with the turbulent journey regarding all political developments.

Even though the price level remained very high over the whole year, some fluctuations can be observed (cf. Figure 2). After the start of the war on Ukraine at the end of February 2022, gas and electricity prices increased significantly in March, reaching an all-time high in August. Fears of potential gas shortages in the coming winter led to these increases in the first half of the year. Electricity prices followed the rising price trend in gas prices[5]. During autumn, prices decreased to almost pre-war levels. In particular, the moderate weather conditions and the high gas storage levels in Europe stopped the upward trend of prices. Low electricity demand, energy savings, high renewable power generation and the reactivation of some coal-fired power plants in Germany further supported the decreasing price trend.

4 Source: transparency.entsoe.eu

5 Gas-fired power stations influence the price determination in electricity markets via the Merit Order where they are, in general, the most expensive production technology which determines the price

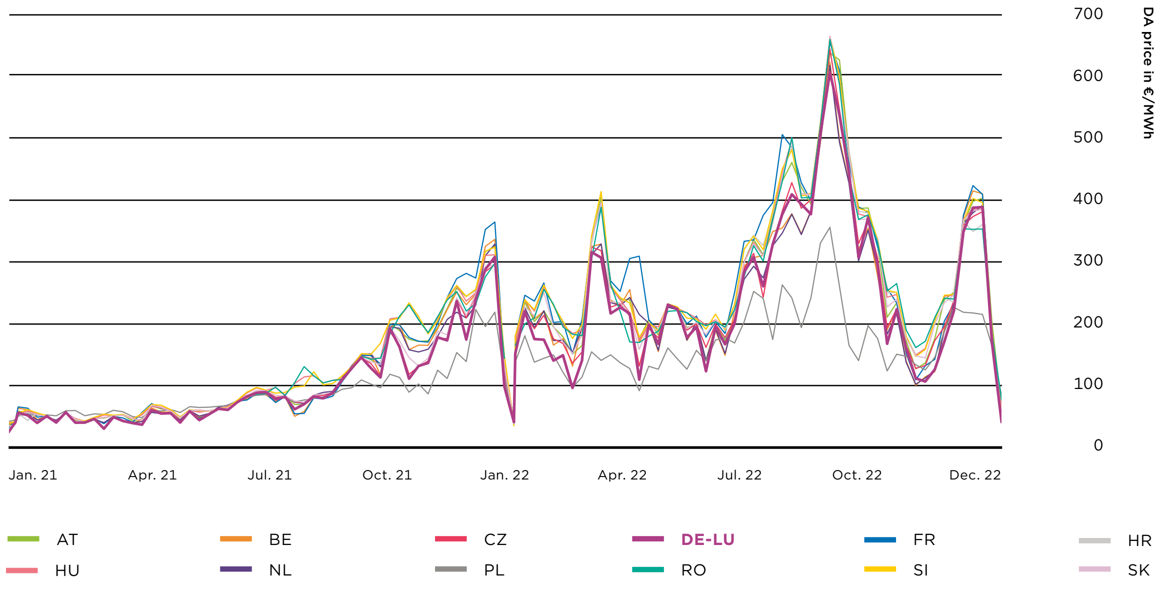


FIGURE 3 Day-ahead prices (weekly average) in Core bidding zones for 2021–2022[6]

Electricity prices have followed a similar pattern throughout Europe. Figure 3 provides a more detailed overview on that, showing the weekly average day-ahead prices of bidding zones in the central European region (Core).

In the light of such price developments throughout Europe, the Council of the European Union adopted its Council Regulation (EU) 2022/1854 on an “emergency intervention to address high energy prices” in October 2022. Among other measures to reduce energy demand and to financially support customers, a cap on market revenues of a maximum of 180 €/MWh for electricity prices was introduced from December 2022 until the end of June 2023 to reduce so-called “windfall” or “excess” profits of power generators. Energy producers from all energy sources, except hard coal and gas, are exposed to this cap, allowing them to realise a maximum electricity price of 180 €/MWh.

DA prices higher than 180 €/MWh were reached in the German-Luxembourgian (DE-LU) bidding zone in around 5,400 hours of 2022. However, since the establishment of the DE-LU bidding zone in October 2018 such high prices have been very rare. Until September 2021, prices above 180 €/MWh were only reached in two hours. For comparison, the DA price exceeded 75 €/MWh in only 1% of the hours in 2020.

6 Source: transparency.entsoe.eu

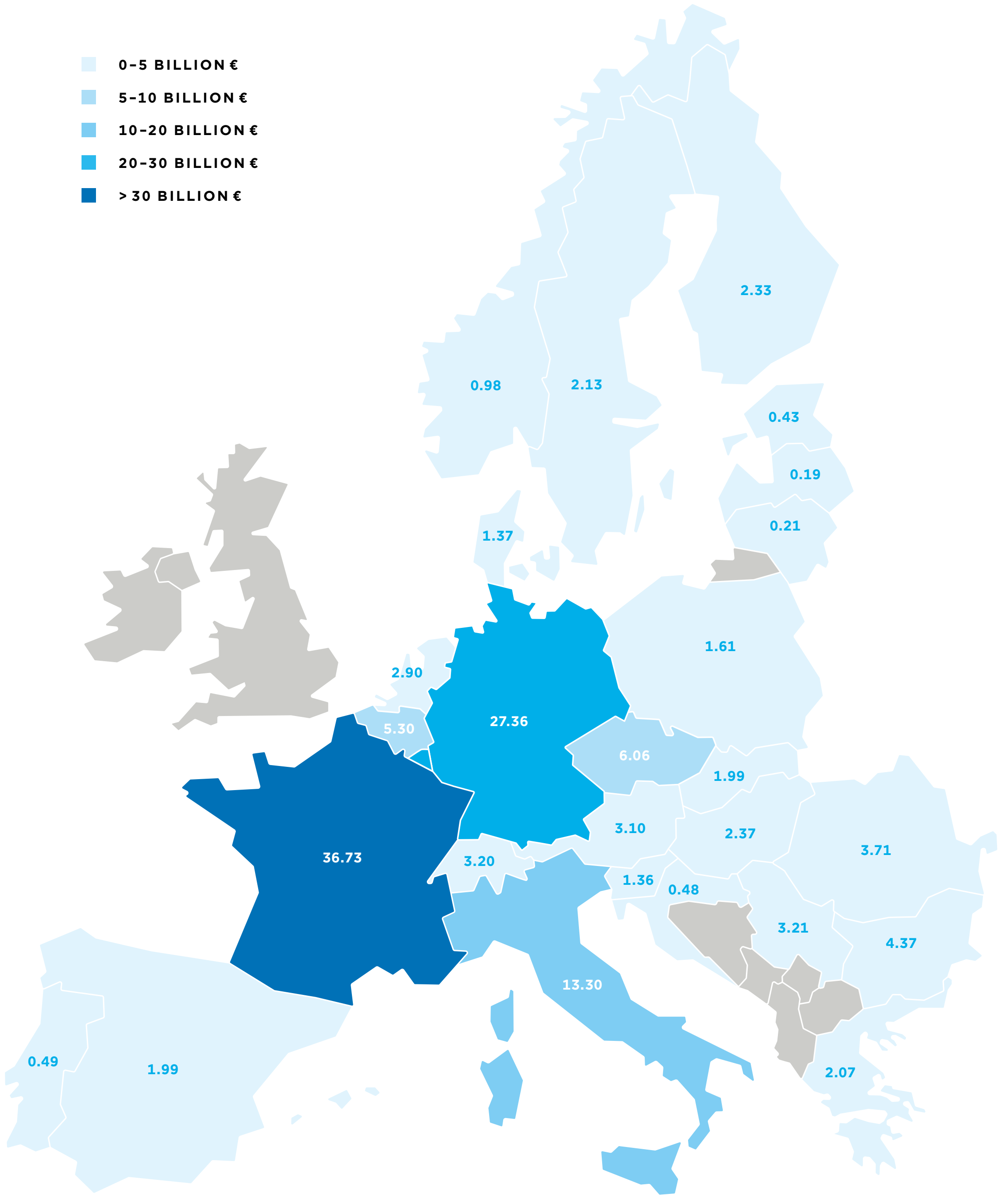


FIGURE 4 Profits due to prices > 180 €/MWh (definition in the Council Regulation) per country in 2022[7]

7 Source: transparency.entsoe.eu

The figures illustrate the potential levy of profits of power generators based on the definition in the Council Regulation (> 180 €/MWh) per country (cf. Figure 4) and per energy source (cf. Figure 5). The two countries/bidding zones with the highest profits under this definition are France and Germany/ Luxembourg. This can be explained by their high electricity demand as well as the high share of nuclear and lignite in their power generation as shown in Figure 5.

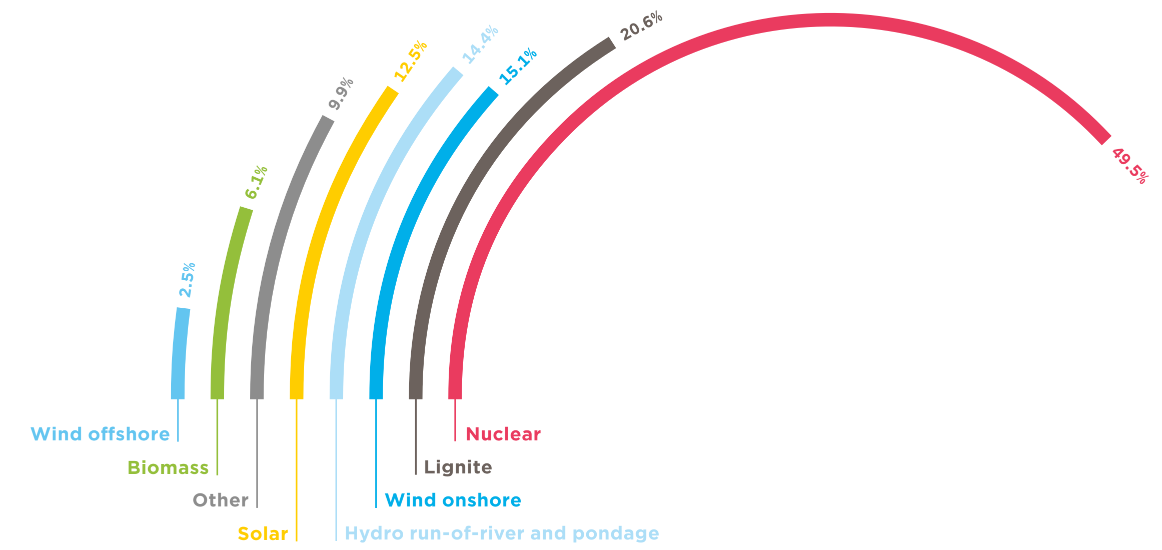


FIGURE 5 Profits due to prices > 180 €/MWh per energy source in 2022[8]

8 Source: transparency.entsoe.eu

MARKET ANALYSIS 2022

The exceptional situation on the European energy markets caused by high gas prices has been significantly exacerbated by water shortages in parts of Europe reducing power plant production (Alpine reservoirs, cooling water, impeded coal transport) as well as by the high unscheduled unavailability of nuclear power plants in France.

RENEWABLE POWER GENERATION IN GERMANY

While electricity and gas prices developed in rather extreme and unique ways during 2022, the power generation by source in Germany also took some interesting developments (cf. Table 1). Compared to 2021, gas-fired electricity production increased slightly by 1%, despite the substantial increase of gas prices, which would suggest a decrease in gas-fired electricity production. Major reasons for this moderate increase are the lack of other available generation capacities as well as the flexibility of gas-fired power plants to react on short-term fluctuations in electricity demand. In order to activate more electricity production, coal-fired power plants which had previously left the market were allowed to return to the electricity market. This ultimately led to an overall increase of coal-fired electricity production by 3%. While offshore-wind, hydro and biomass electricity production remained at constant levels, generation by onshore wind and in particular solar generation increased in 2022 compared to 2021.

	Solar	Wind onshore	Wind offshore	Hydro	Biomass	Natural gas	Coal	Nuclear	Others
2020	9%	21%	5%	5%	8%	12%	24%	12%	2%
2021	9%	18%	5%	5%	8%	10%	30%	13%	3%
2022	11%	20%	5%	5%	8%	11%	33%	6%	2%

TABLE 1 Overview of power generation in Germany in 2020–2022 by source[9]

9 Source: transparency.entsoe.eu

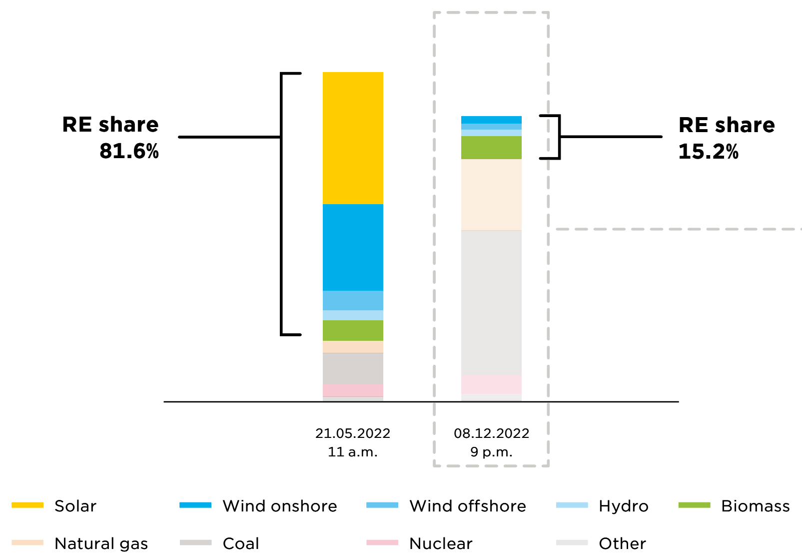


FIGURE 6 Highest and lowest share or renewable (RE) power generation in Germany in 2022[10]

The experience of 2022 illustrates the need for appropriate flexible generation capacities which must be available during times with low renewables infeed.

Hourly renewable energy production reached its annual high on 21 May 2022 at 11 a.m. with a share of 82% (40% solar, 32% wind, 10% other renewables) of total energy production (cf. Figure 6). In comparison, renewable energy production reached its lowest level on 8 December 2022 with only 15% (0% solar, 5% wind, 10% other renewables) of total electricity production at 9 p.m., followed by a period of relatively low renewable energy production and imports, until 12 December 2022 (cf. Figure 7). During this period, several French nuclear plants were out of operation and subsequently French electricity imports reached relatively high amounts of above 10 GW (cf. Figure 8).

10 Source: transparency.entsoe.eu

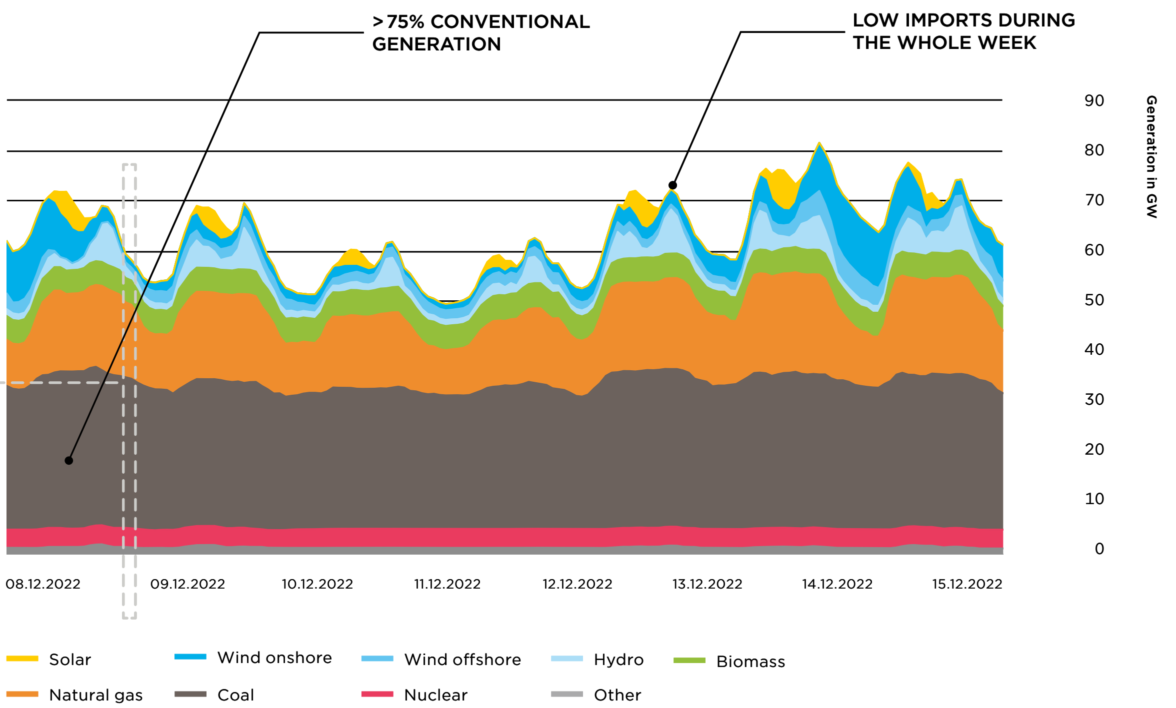


FIGURE 7 Power generation in Germany from 8 to 15 December 2022 by source[11]

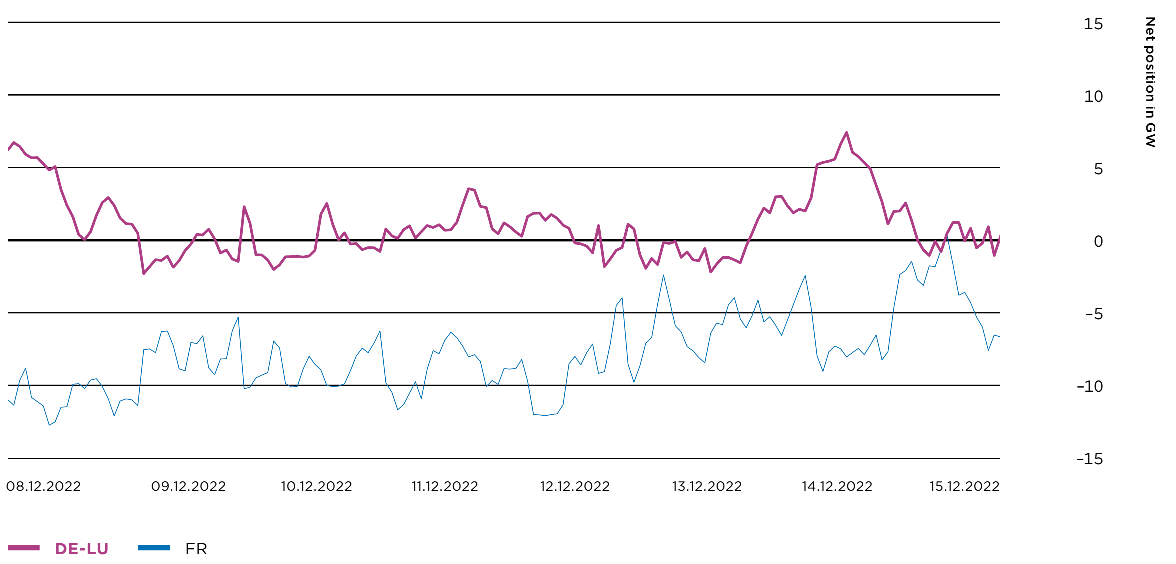


FIGURE 8 Net positions of Germany and France from 8 to 15 December 2022[12]

11 Source: transparency.entsoe.eu
12 Source: transparency.entsoe.eu

This fluctuating pattern of renewables illustrates the need for appropriate flexible and controllable generation capacities and flexibilities in a future electricity system which must be available during times with low renewables infeed. This becomes even more important in situations where neighbouring countries are relying only on imports and electricity demand in the home market cannot be simultaneously covered from abroad. Together with other aspects of system stability, this aspect must be consistently taken into account in a holistic system and market design (cf. "Systemmarkt" proposal in the "Future developments" chapter).

EXPORTS AND IMPORTS

Electricity exports and imports to and from bidding zones are represented by their net positions. As the net positions reflect the difference between exports and imports, a positive net position indicates a (net) exporting bidding zone, while a negative net position shows a (net) importing bidding zone.

The net exports of Germany increased significantly from 24 TWh in 2021 to 28 TWh in 2022. German imports increased slightly from 36 TWh to 37 TWh while in combination with continued growth of exports to 65 TWh, as displayed in (cf. Figure 9). In contrast, both the maximum DA exports and imports within one hour for Germany remained on a constant level.

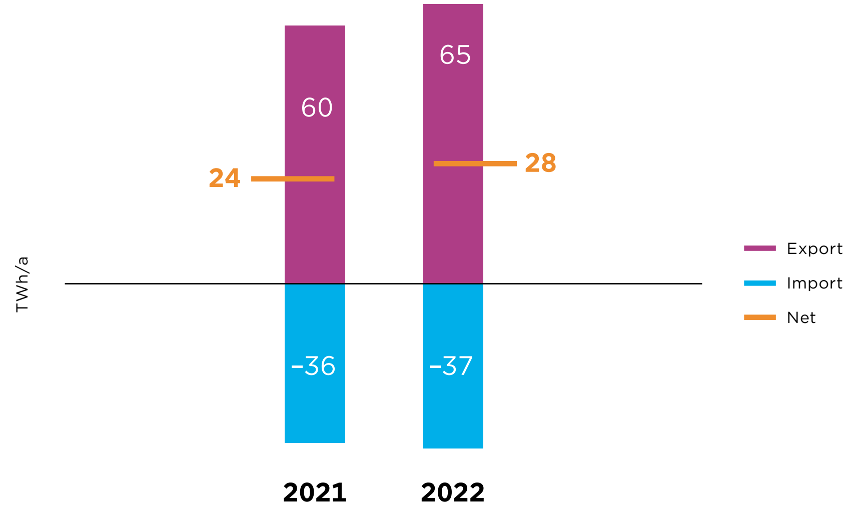


FIGURE 9 Yearly day-ahead exports and imports of Germany for 2021 and 2022[13]

13 Source: transparency.entsoe.eu

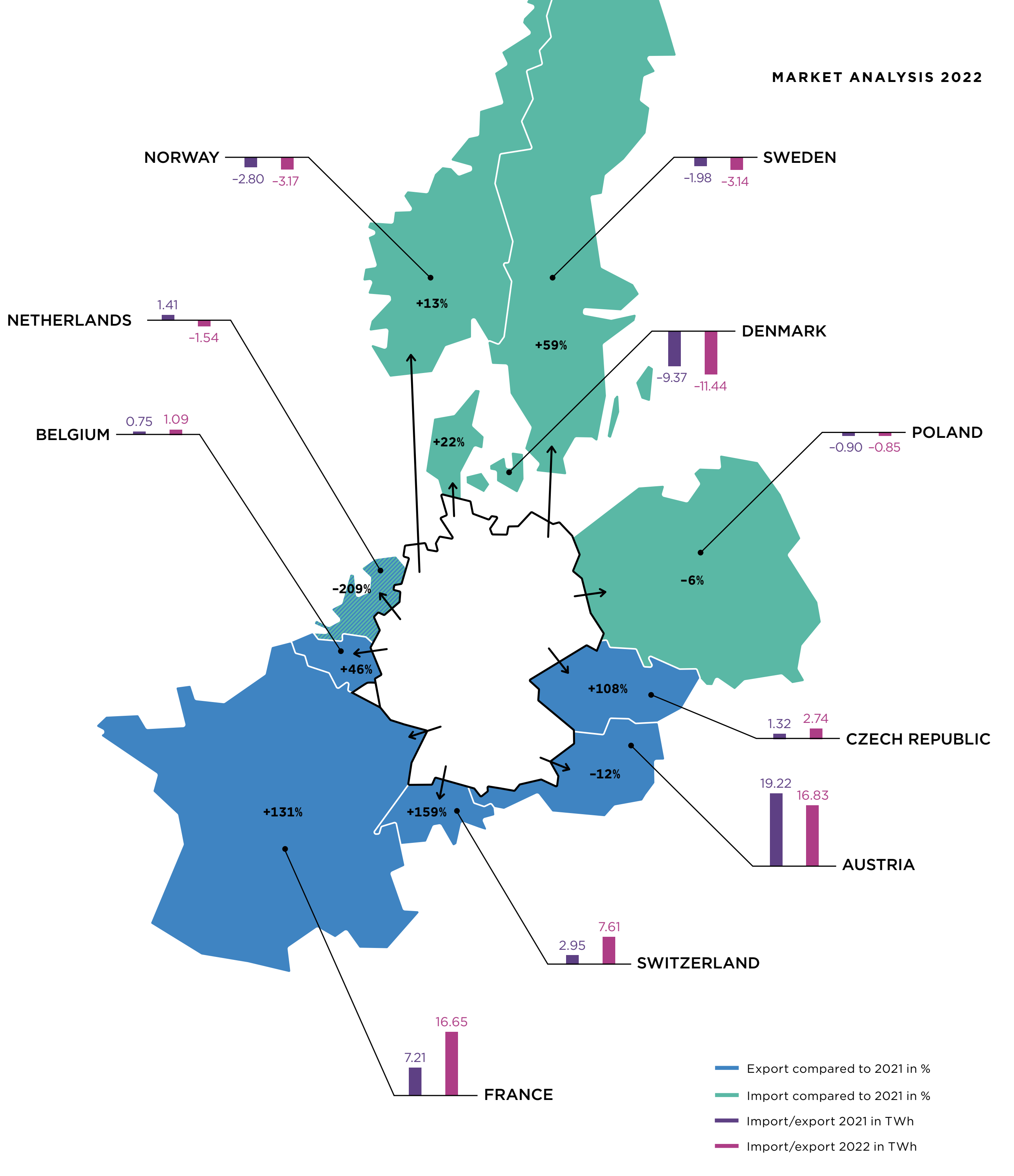


FIGURE 10 Yearly day-ahead exports and imports of Germany with its neighbouring countries in 2022[14]

14 Source: transparency.entsoe.eu
Positive values (TWh) display exports from Germany (blue), while negative values display imports to Germany (green).

All exchanges between Germany and its neighbouring bidding zones on a border-by-border basis are illustrated in Figure 10. While Germany had been largely exporting towards the Netherlands in 2021, the year 2022 shows a change with Germany now being a net importer at this border. The most significant changes have taken place at the borders to Switzerland and France where German exports have increased substantially to two times more than 2021.

Germany's net exports to France grew by around 130% in 2022 while nuclear-based power generation in France dropped by up to 23% during the summer months.

The increase of exports from Germany to France can be explained by taking a closer look at the development of the net positions of both bidding zones in 2021 and 2022 (cf. Figure 12). During 2021, the French bidding zone was exporting electricity during the summer months while importing during the winter months. This pattern changed in 2022 where nuclear-based power generation in France dropped by up to 23% during the summer months compared to 2021, leading to a new record of French electricity imports from Germany. Over the entire year 2022, 12% less nuclear power was generated compared to the average level from 2015 to 2021 (cf. Figure 11).

In 2022, several nuclear power plants in France were at least temporarily unavailable due to maintenance and refurbishment work. The situation worsened in the summer due to drought and the resulting difficulties for cooling due to low river levels. Overall, France's electricity consumption in 2022 of 443.1 TWh could only be counterbalanced with 439.9 TWh of domestic production. While consumption only decreased by 5%, production, however, was almost 15% lower than the year before. It was therefore necessary to import electricity to meet the demand. With an average wholesale electricity price of 276 €/MWh, it was also economically reasonable to buy electricity from other countries such as Germany.[15]

Due to the high interdependence between the European grids and in the European electricity market, the situation in France also impacted Switzerland. Normally, Switzerland imports electricity during the winter months, for example from France and Germany. This was not the case in 2022. In addition to lower imports from France, water levels in Swiss rivers were low, and snowfall and rain were relatively little. This prolonged drought caused a further reduction in water reserves in the reservoirs and hence led to increased imports from other countries such as Germany to Switzerland.[16]

	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sept.	Oct.	Nov.	Dec.	Total
Average 2015–2021	34.18	29.85	29.20	24.43	23.96	23.89	23.55	23.51	23.52	25.32	25.92	29.60	316.94 TWh
2022	35.23	29.48	26.78	21.74	20.46	20.17	18.72	18.08	18.14	20.13	21.54	27.80	278.26 TWh

FIGURE 11 Nuclear power generation in France in 2022 compared to the average of 2015–2021[17]

15 Source: smard.de/page/home/topic-article/444/209624

16 Source: swissinfo.ch/ger/wirtschaft/stromluecke-energiekrise_wie-die-schweiz-das-bibbern-im-dunkeln-verhindern-will/47871220

17 Source: transparency.entsoe.eu

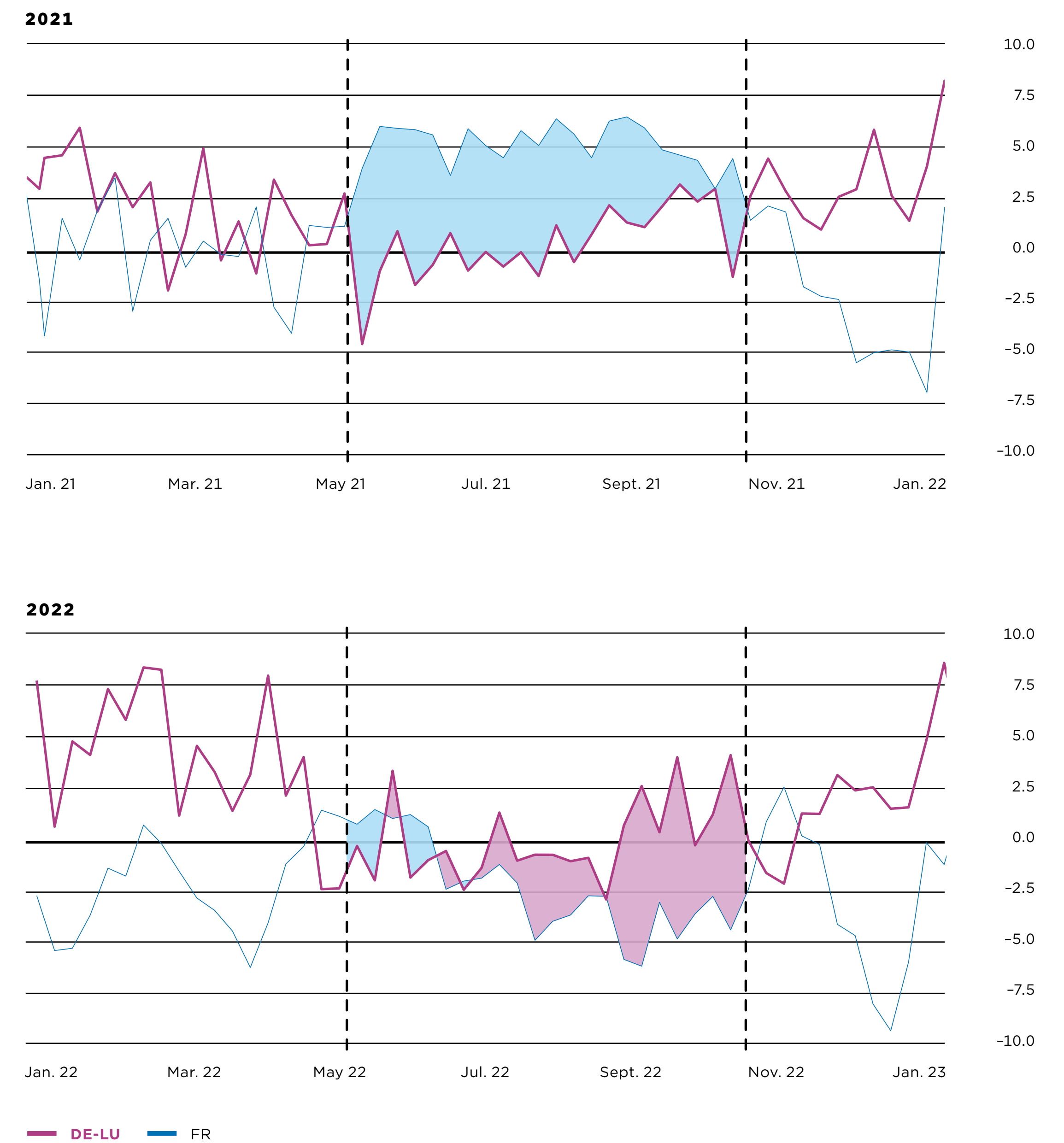


FIGURE 12 Comparison of day-ahead net positions of DE-LU and FR in 2021 and 2022[18]

18 Source: transparency.entsoe.eu

EXCURSUS

CORE CAPACITY CALCULATION REGION (CCR)

The European electricity market has been undergoing significant changes in recent years with the increasing integration of renewable energy sources and the implementation of the Energy Union Strategy published in 2015. In this context, the Core project has been initiated to address the challenges for the European electricity market and to improve its integration and efficiency.

Electricity imports and exports take place via the transmission grid whose transmission capacity is made available for this purpose. The Core project is a collaboration between several European TSOs for developing a harmonised methodology for the calculation of such transmission capacity. This methodology ensures a fair and transparent allocation of transmission rights, enabling the integration of renewable energy sources into the European electricity market. After the interim introduction of ATC (Available Transfer Capacity) market coupling in 2010 and the implementation of Flow-Based Market Coupling (FB MC) in Central and Western Europe (CWE) in 2015, the Core project represents the next big milestone of European market integration.

The first phase of Core went live on 8 June 2022, implementing the Day-Ahead Flow-Based Market Coupling in a common CCR of 13 countries. Beside the implementation of the day-ahead time frame, Core TSOs are also working on the implementation for the intraday and long-term time frame as well as on other improvements, such as a coordinated redispatch or balancing process.

FIRST SUCCESS: DAY-AHEAD FLOW-BASED MARKET COUPLING

The methodology was put into practice when the Core Day-Ahead Capacity Calculation (DACC) was successfully launched on 8 June 2022. Since then, this complex capacity calculation and allocation process has been running stably, enhancing the day-ahead market coupling of wide parts of Central Europe. It consists of 16 sub-steps and takes up to 22 hours in normal operation. The daily capacity calculation process requires 16 TSOs and two Regional Coordination Centres (RCCs) to closely collaborate in a coordinated manner. The operational staff, both central and many local tools, data interfaces and IT infrastructures all need to cooperate efficiently and coherently to ensure a daily reliable capacity calculation and allocation process.

IN THE LONG RUN: LONG-TERM CAPACITY CALCULATION (LTCC)

Further to the short-term (day-ahead) capacity calculation the "Long-term capacity calculation methodology of the Core capacity calculation region" was published on 3 November 2021 and amended by ACER on 18 January 2023. From 2025 onwards, the calculation and allocation of cross-border long-term capacities will follow a coordinated approach within the Core region. This approach will replace existing bilateral agreements.[19] The capacity calculation will be executed by RCCs based on some specific scenarios. This calculated long-term flow-based capacity is based on eight to ten different timestamps, which represent specific grid situations within one month (two for each week) and 24 timestamps representing one year (two for each month).

NEXT STEP: INTRADAY CAPACITY CALCULATION (IDCC)

Further to the long-term and day-ahead timeframe, cross-zonal capacities are offered to the intraday market. After alignments and local validation processes, these capacities are offered to continuous intraday trading at 10 p.m. D-1. This currently local approach will be enhanced and harmonised by applying the flow-based approach to calculate cross-zonal intraday capacity in the overall Core region as of June 2023. In this calculation, the most recent available information related to the grid situation will be used. Moreover, the IDCC process will also include a validation step, which allows TSOs to modify the calculated capacities[20] for reasons of operational security. In both time frames, day-ahead and intraday, APG, TenneT NL and the German TSOs perform this individual validation in a joint approach using the Day-Ahead Validation of Capacity (DAVinCy) and Intraday Validation of Capacity (IDAVinCy) tool.

FURTHER IMPROVEMENT: DAVINCY

According to Article 16(8) of Regulation (EU) 2019/943 on the internal market for electricity, TSOs are obliged to provide a minimum level of transmission capacities to the market. This could lead to situations where in later forecast processes or in real-time operation, the actual physical transmission capacity levels may be exceeded. The resulting congestions must be solved by remedial actions (RAs) to ensure operational security. The Core DA Capacity Calculation Methodology enables a reduction of the Remaining Available Margin (RAM) on Critical Network Elements and Contingencies (CNECs) in case of insufficient available RAs to remove these congestions.

With increasing cross-border flows in Europe, the application of RAs can no longer be limited to local measures of single TSOs. The amount of required multilateral European RAs will probably increase and already today significant amounts between Germany/Luxembourg, Austria and the Netherlands are reached. Therefore, the TSOs involved have developed and are using a common individual validation tool when calculating transmission capacities. The underlying process is called DAVinCy (Day-Ahead Validation of Capacity). DAVinCy determines the necessary Individual Validation Adjustments (IVAs) on relevant CNECs with the objective of minimising the overall transmission capacity reduction among the six DAVinCy TSOs[21]. Transmission capacities (RAMs) will only be reduced to the minimum degree that is needed to ensure operational security[22].

The joint DAVinCy validation has the following advantages:

- Maintaining operational security with the best possible consideration of available RAs
- Better consideration of cross-border-relevant RAs to minimise capacity reductions
- Lower capacity reductions compared to independent validation of all six TSOs

In conclusion, optimal capacity adaptions do not always correspond to congestions in the same control area. DAVinCy results very often show that congestion in one control area can be most efficiently addressed with an IVA application in one or more adjacent control area(s). This can lead to situations where an overload occurs in one control area of TSO A whereas the IVA(s) is/are applied within other control areas, e.g. of TSOs B and C.

THE NEXT BIG THING: COORDINATED REDISPATCH AND COST-SHARING PROCESS

The regional coordination of RAs will be further enhanced by the optimised and coordinated implementation of redispatch and countertrading (RDCT) actions. The goal of the region-wide RDCT optimisation is to determine the most efficient set of remedial actions in order to mitigate all congestions in the Core areas. Additionally, a mechanism for cost-sharing will be implemented. The purpose of this cost sharing mechanism is to identify the bidding zones which contribute to the congestions and assign a corresponding fraction of the total costs to them.

The implementation of the RDCT coordination and optimisation process as well as the related cost-sharing mechanism are planned to go live in 2025 and will be further refined in the following years. The implementation of these two processes will be beneficial for the whole Core region, as a cost-optimal determination of RDCT measures and a fair cost allocation will contribute to system security.

19 In particular, the 4.9 GW DE-AT long-term capacity
20 The so-called Remaining Available Margin (RAM)
21 If a remaining overload occurs
22 Considering all expected available costly and non-costly RAs

PRICE CONVERGENCE AND MARKET-LIMITING GRID CONSTRAINTS

The overall developments on the European electricity market in 2022 had a significant impact on trade and price formation. Likewise, the go-live of the Core capacity calculation region marked an important step in European market coupling, which had a positive influence also on national markets.

The reduction of price differences and increasing price convergence[23] 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 Core 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. Besides the price convergence, which is related to a perfect fit of supply and demand, 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 it is the basis for the generation of congestion income for TSOs. This congestion income is then earmarked for investments in grid expansion in order to increase cross-zonal trade capacities and to reduce price spreads in the future.

As shown previously in this chapter, the net exports of Germany increased in 2022 by around 7 TWh or nearly 30% compared to 2021. From a market perspective, this represents a real benefit, reducing the prices in neighbouring countries and contributing to the overall welfare. However, this increase in exports goes hand in hand with a higher utilisation of the transmission grid. In addition, following the German action plan, the minimum Remaining Availability Margin (minRAM) provided to the market was raised from 21.3% to 31.0% in 2022 and even further increased to 40.8% in November 2022, prior to the originally scheduled time target of January 2023. The decision to increase the minRAM target sooner than envisaged in the action plan demonstrates Germany's commitment to ensuring security of supply in Europe during winter 2022.

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

The shift from CWE to Core and, in particular, the turbulences on the European energy markets in 2022 have decreased the representativeness of comparisons of indicators such as price convergence or spreads with previous years. The massive increase in wholesale electricity prices automatically affected the average price spreads. As shown in Figure 13, the rise of the DA price level correlates linearly with the observed average price spread. While in 2020 the average DA price was around 30 €/MWh, the average price spread[24] was around 6 €/MWh (20% of the average DA price). These values peaked in Q3 2022 with an average DA price of 386 €/MWh and an average price spread of 64 €/MWh (17%). Consequently, the high prices and the general situation on the electricity markets also affected the price spreads and hence the price convergence between the bidding zones. The go-live of the Core CCR had a significant impact as well. One major goal of a CCR is to increase the overall welfare, which is not necessarily reached by maximising price convergence. For that reason, an evaluation of market integration progress in terms of indicators such as price spreads would not be representative.

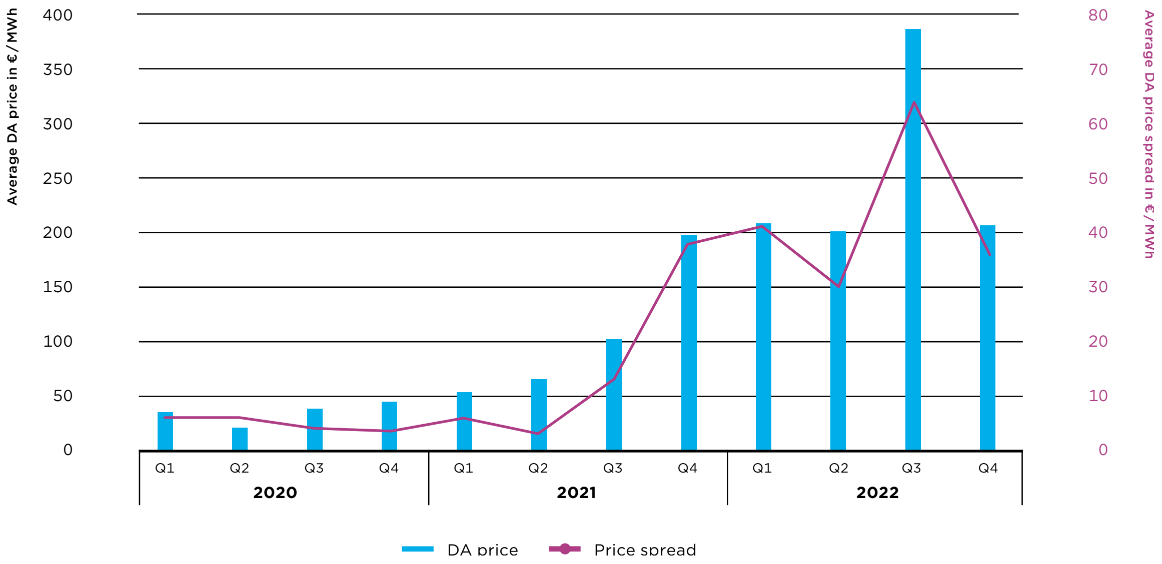


FIGURE 13 Average day-ahead price and price spread in Core in 2022 by quarter[25]

Looking at the average price spread on all Core borders, the price spreads in the south-eastern part of the CCR are the lowest (cf. Figure 14). This is, among other aspects, related to the similar power generation structure in most of these countries. Price spreads have been the highest at the Polish borders. With regard to Germany, the average price spread on all borders was around 42 €/MWh in 2022.

24 At today's Core CCR borders
25 Source: transparency.entsoe.eu

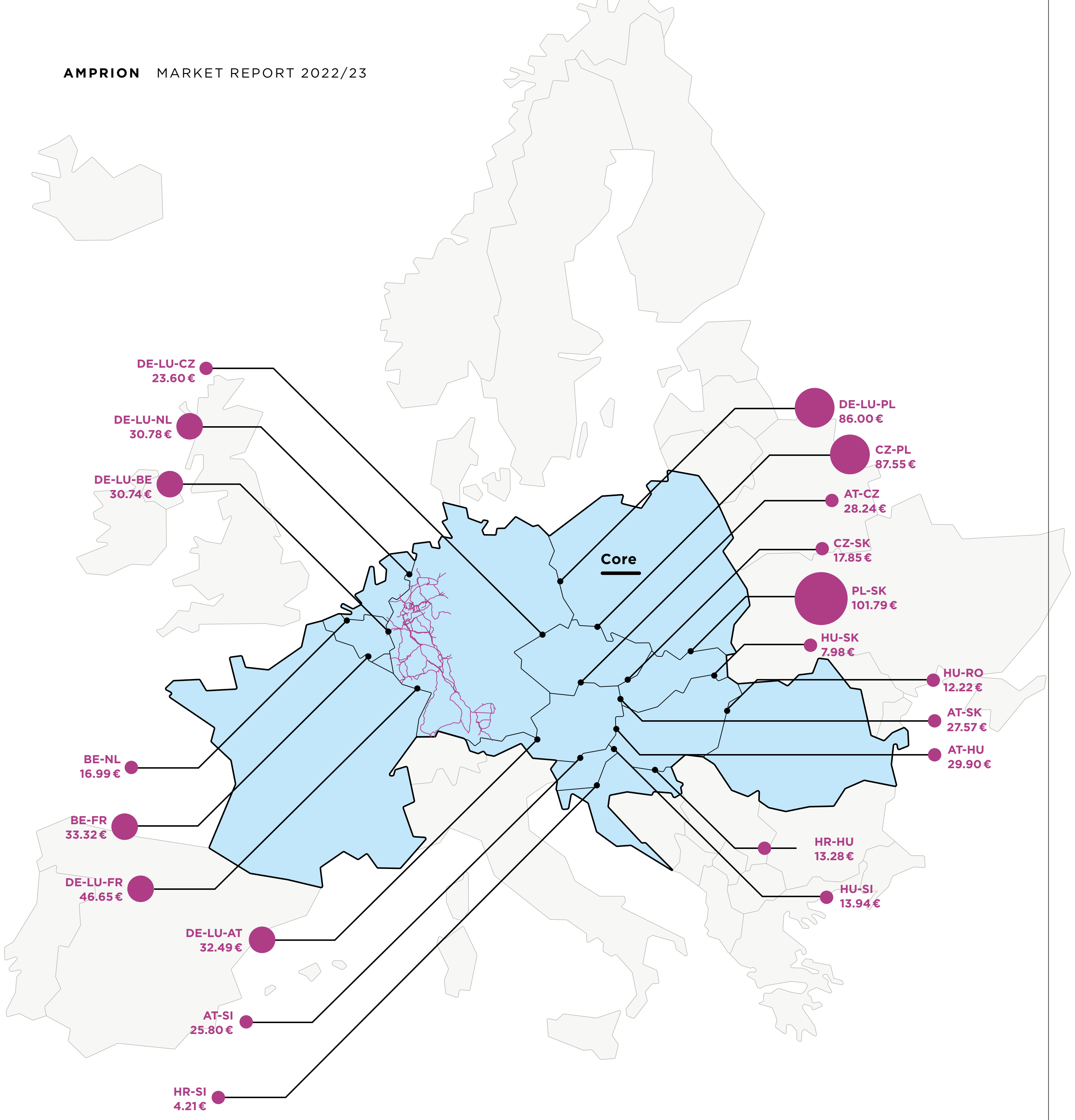


FIGURE 14 Average price spread in Core in 2022 by border[26]

26 Source: transparency.entsoe.eu

High imports and exports have led to a higher utilisation of the transmission grid and more complex grid situations – with a high number of simultaneous market-limiting grid elements.

In general, price convergence indicates that there are no transmission grid limitations of cross-border trade. Otherwise, situations in which there is still a price spread between two bidding zones correspond to limitations due to the grid. Figure 15 further illustrates such different market and grid situations CWE (until 8 June) and Core (from 9 June). It reveals a general trend towards more complex grid situations where various network elements are limiting cross-zonal trade. On the one side, this can be explained by the tenser situation in power generation in the second half of 2022. On the other side, this effect is related to the simple expansion of the capacity calculation region (CCR) with additional countries and transmission grids. In the CWE region in 40% of the time, there was no limitation of trade and full price convergence. With the expansion to Core, this value dropped to around 25%. In both regional configurations the following reasons caused a limitation of trading impeding full price convergence in 2022:

- During 10.5% (CWE) / 8.3% (Core) of the time the capacity of interconnectors between bidding zones was insufficient to accommodate unlimited electricity exchanges.
- During 46.8% (CWE) / 63.5% (Core) of the time, both interconnectors and internal network elements constrained exchanges. In comparison to 2021, such situations have increased significantly.
- Internal network elements solely have been constraining market exchanges during 2.7% (CWE) / 3.3% (Core) of the time, with a 0.5% (CWE) / 0.2% (Core) Amprion share.

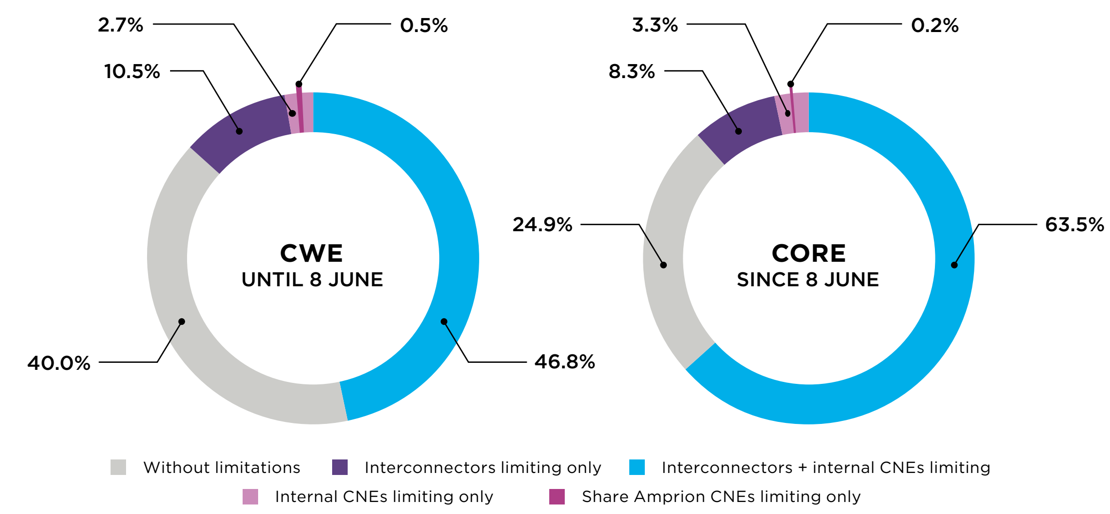


FIGURE 15 Share of hours in which trade in CWE and Core was constrained by internal CNEs or interconnectors in 2022[27,28]

27 Please note that allocation constraints are not considered.

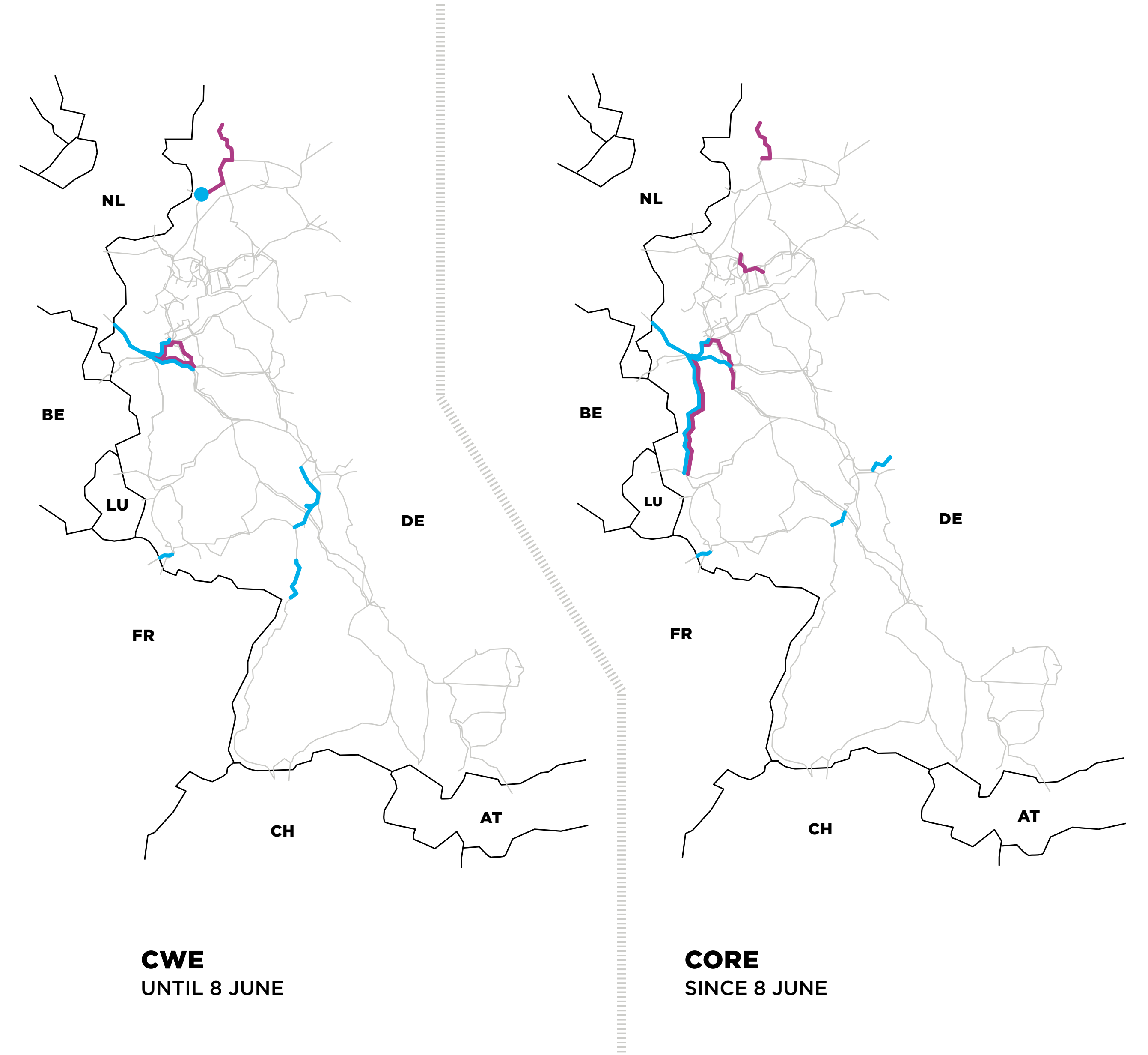
28 The general information about the critical branches can also be downloaded via the utility tool available via JAO, see utilitytool.jao.eu

GEOGRAPHICAL LOCATION OF LIMITING AMPRION ELEMENTS

Need-oriented grid expansion remains a top priority

Our control area is located in the heart of Europe and the Core CCR. This particular role in Germany and Core requires our strong commitment to the overall European electricity market. Therefore, our strategy for the optimal operation and extension of the grid has high relevance for the whole electricity market.

Figure 16 illustrates the top 10 of Amprion's critical network elements with the lowest capacity offered to the market (pink) as well as the top 10 of Amprion's network elements that most often limited trade in 2022 (blue). Grid enhancement should, in particular, take place in areas where trading limitations occur (i.e. blue). In these areas, more trading is requested by the market which could be realised by an extended grid. On the contrary, the grid elements with the lowest capacity offered to trading (pink) are not always the best indicator for grid development. Lower trading margins might be acceptable here – in case the market does not request more trading possibilities. In order to provide incentives for an efficient grid expansion, both the offered and actually used capacity have to be evaluated together. Consequently, network elements that stand out in both categories are an indicator that their expansion will most likely result in significant welfare gains. Since the going live of Core in June 2022, there has been a slight shift of the most affected network elements in both categories. However, the general regions and hotspots remain the same: the Emsland region in the north of Amprion's control area, the area around the city of Cologne as well as on the southern and south-eastern borders of the control area. Related to the described increased exports to France, the cross-border transmission lines between Vigy and Ensdorf stand out over the whole year.



Top 10 critical network elements (CNEs) in 2022

With lowest offered trading margin for cross-zonal trade

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

FIGURE 16 Location of major (top 10) active critical branches in Flow-Based Market Coupling of Amprion as well as the ones with the lowest offered trading margin in 2022

EXCURSUS

GO-LIVE OF EUROPEAN BALANCING PLATFORMS MARI AND PICASSO

For a long time, balancing processes in Europe remained, to a large extent, at a national level. The entry into force of the Commission Regulation (EU) 2017/2195 establishing a guideline on electricity balancing (EB) was the starting point for the integration of balancing markets in Europe. This European integration of balancing markets is expected to enable procurement of balancing services in a fair, transparent and market-based way while, at the same time, ensuring cost-optimal system operation.

In 2022, the Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO) and Manually Activated Reserves Initiative (MARI) became operational. They enable the cross-border activation of frequency restoration reserves (FRR) with automatic activation (aFRR) and manual (mFRR) activation. These initiatives have enabled further social welfare gains – in addition to already achieved gains through cross-border TSO cooperation in terms of balancing capacity and imbalance netting. Together with the existing platforms TERRE (Trans European Replacement Reserves Exchange) and IGCC (International Grid Control Cooperation), MARI and PICASSO complete the implementation of the European target market design for balancing energy at the European level. The European TSOs' accession process to the platforms is expected to be finalised in 2024. This will ensure common principles, harmonised products and methodologies for the functioning of balancing energy markets across Europe. The timely initialisation of the platforms in 2022 has been a success of TSO cooperation which will lead to significant economic benefits in the following years.

IGCC and PICASSO are both hosted by TransnetBW. Having started as a voluntary regional project of German TSOs in October 2010, IGCC has grown to cover 24 countries (27 TSOs) across continental Europe and has been established as the official balancing platform by the EB Regulation. TSOs participating in IGCC have been able to reduce their imbalances to be covered by the counter activation of aFRR balancing energy by up to 70% through imbalance netting via the platform. In 2021, Europe-wide savings summed up to 316 million Euro. PICASSO became operational in June 2022. In the first six months of operation, PICASSO generated total social welfare gains of around 340 million Euro.

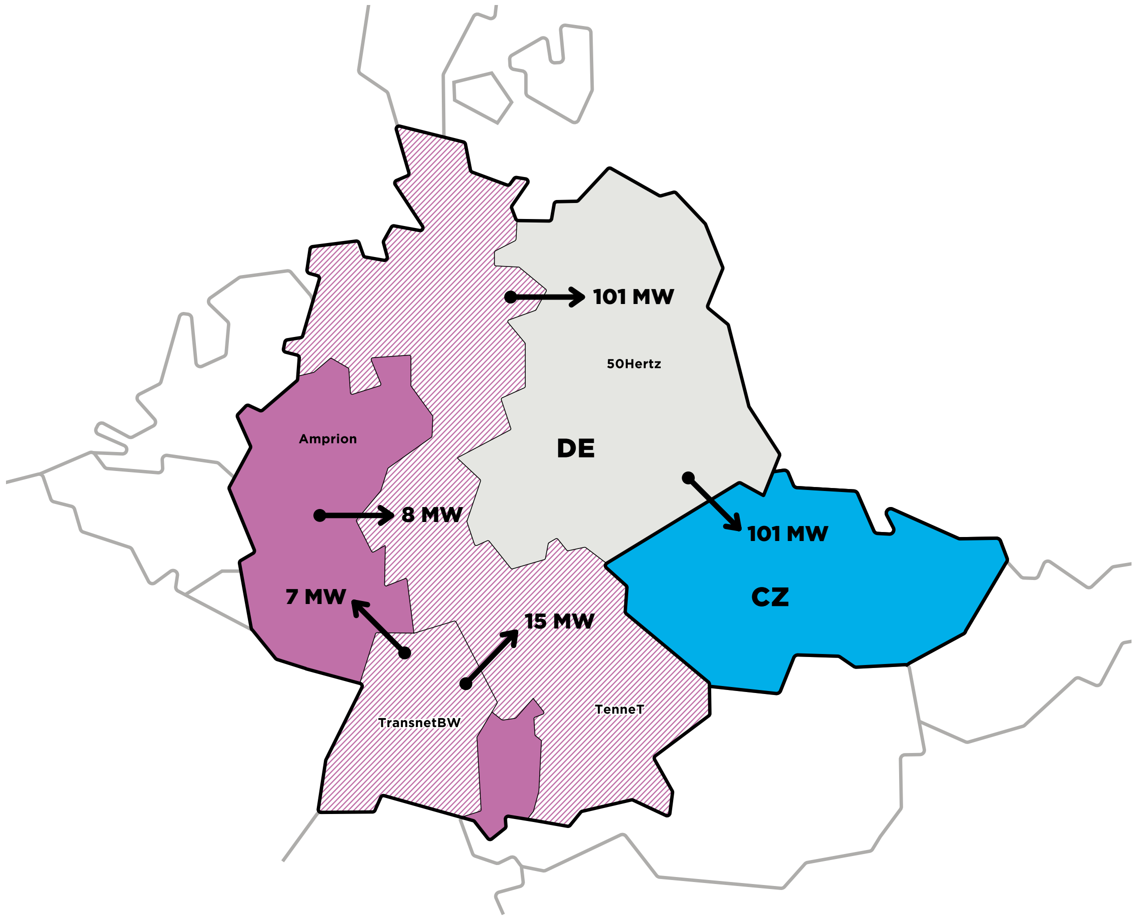


FIGURE 17 Exemplary activation of positive mFRR via MARI

MARI is hosted by Amprion who is also the Common Service Provider (CSP) of the project. The CSP is also coordinating the development of MARI on behalf of all MARI TSOs. This activity includes the core functions of MARI, consisting of the optimisation of the mFRR activation in real-time and the TSO-TSO settlement function. Amprion thus plays a central role in enabling the cross-border activation process for FRR balancing energy across Europe and contributes significantly to the realisation of considerable welfare gains.

In October 2022, the Czech TSO CEPS and the German TSOs connected to MARI, resulting in 151 cross-border mFRR activations in the first three months of operation. Welfare gains are generated by cross-border mFRR activations through MARI as activations only take place if the mFRR bids abroad are cheaper, provided that sufficient cross-zonal capacity is available. Exact figures on social welfare gains from MARI will be published later in 2023, after a sufficient database has been established. An example of its operation is provided in Figure 17.

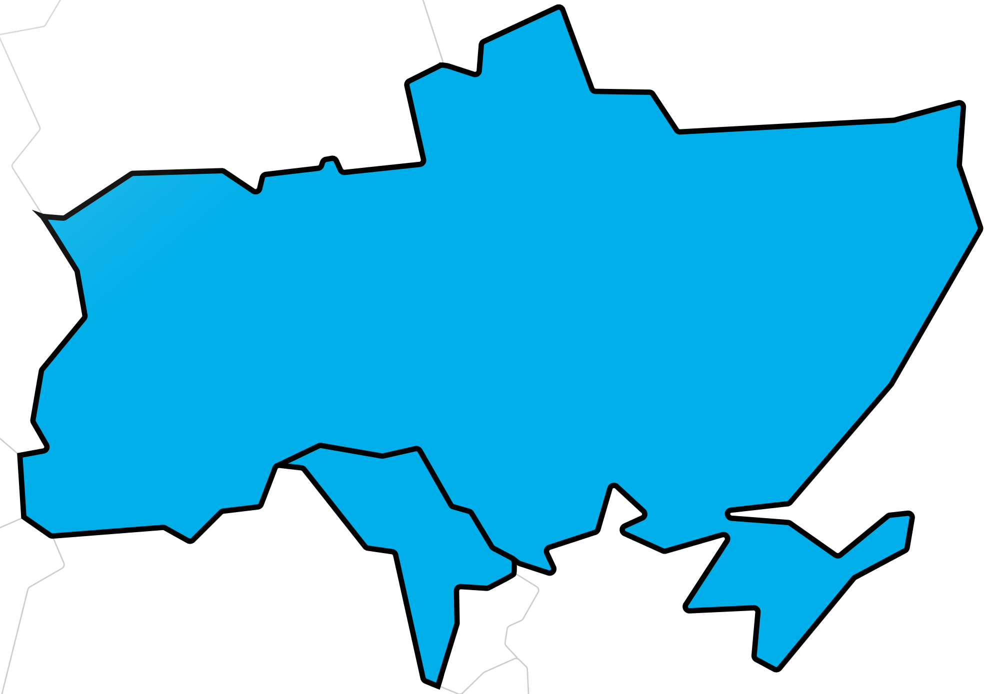
For the given example, CEPS submitted a demand of 150 MW positive mFRR to MARI. This request was satisfied by the activation of 101 MW of positive mFRR in Germany for the Czech Republic (0 MW by 50Hertz, 1 MW by Amprion, 78 MW by TenneT TSO DE and 22 MW by TransnetBW). The remaining 19 MW of positive mFRR were activated in the Czech Republic via MARI.

EXCURSUS

SYNCHRONISATION OF UKRAINE AND MOLDOVA WITH THE CONTINENTAL EUROPE GRID

Since 16 March 2022, the electricity grids of Ukraine and the Republic of Moldova have been synchronised with the Continental Europe Grid. Amprion has played a decisive role in this emergency synchronisation as a contribution to the stable electricity supply of Ukraine and the Republic of Moldova.

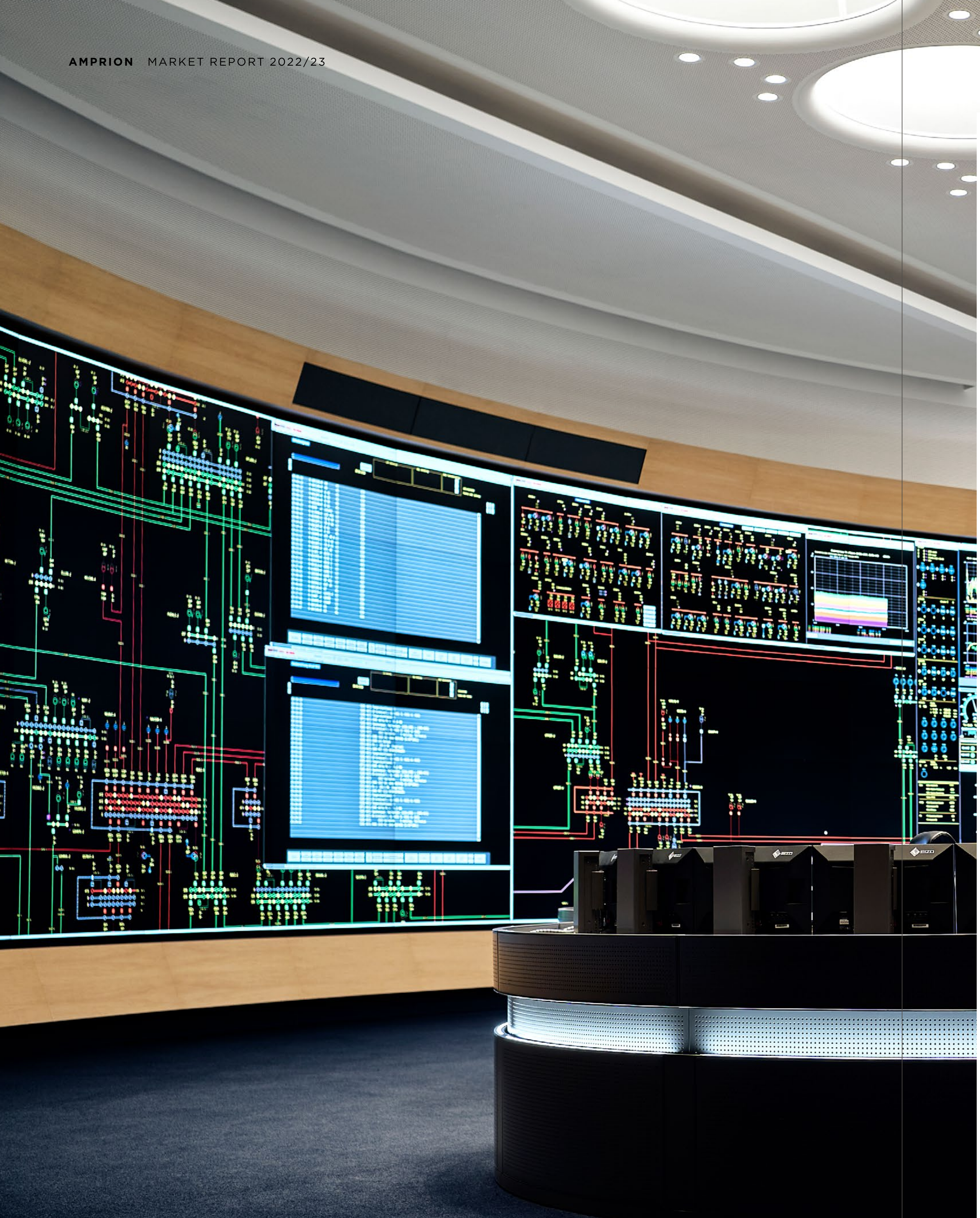
As of 2017, the permanent synchronisation of the Ukrainian and Moldovan electricity grids has been prepared as part of an ENTSO-E project. According to the original planning, the synchronisation was supposed to take place in 2023. At the urgent request of Ukraine and the Republic of Moldova, however, this timeline was brought forward significantly enabling a synchronisation in just two weeks after the start of the Russian invasion of Ukraine. The actual synchronisation – the step-by-step interconnection of the grids – began on Wednesday, 16 March 2022, at around 11 a.m. and was successfully completed within a few minutes. The system stability of the synchronous grid of continental Europe was not endangered at any time.



During the emergency synchronisation of Ukraine and Moldova with the Continental European Synchronous Area, the Coordination Centres Amprion and Swissgrid in cooperation with ENTSO-E took responsibility for a variety of tasks:

- Establishing appropriate communication channels and secure data transmission between the transmission system operators of Ukraine (Ukrenergo) and the Republic of Moldova (Moldelectrica) and the TSOs of continental Europe
- The actual synchronisation of the networks and transfer to regular system operation
- Monitoring of system stability and dynamic network behaviour
- Clarification of legal, economic grid management and regulatory issues
- Accompanying the political discussions at the European level

This extremely fast and successful yet complex process of synchronisation demonstrates the strong collaboration between European TSOs, especially in times of crisis.



GRID OPERATION ANALYSIS 2022

Redispatch volumes and costs reaching all-time high in 2022

The generation of electricity at particular grid locations causes electrical load flows. In the event that such load flows exceed the technical limitations on particular network elements, the power generation pattern has to be changed. This process is called redispatching, where TSOs must reduce power generation at dedicated locations in the grid in order to alleviate the power flow on constrained network elements[29].

Already in 2021 redispatch volumes and costs in Germany increased significantly compared to the previous year. The year 2022, however, showed even higher increases. As illustrated in Figure 18, the redispatch volume in the Amprion control area increased by more than half of the 2021 value and redispatch costs more than doubled compared to 2021.

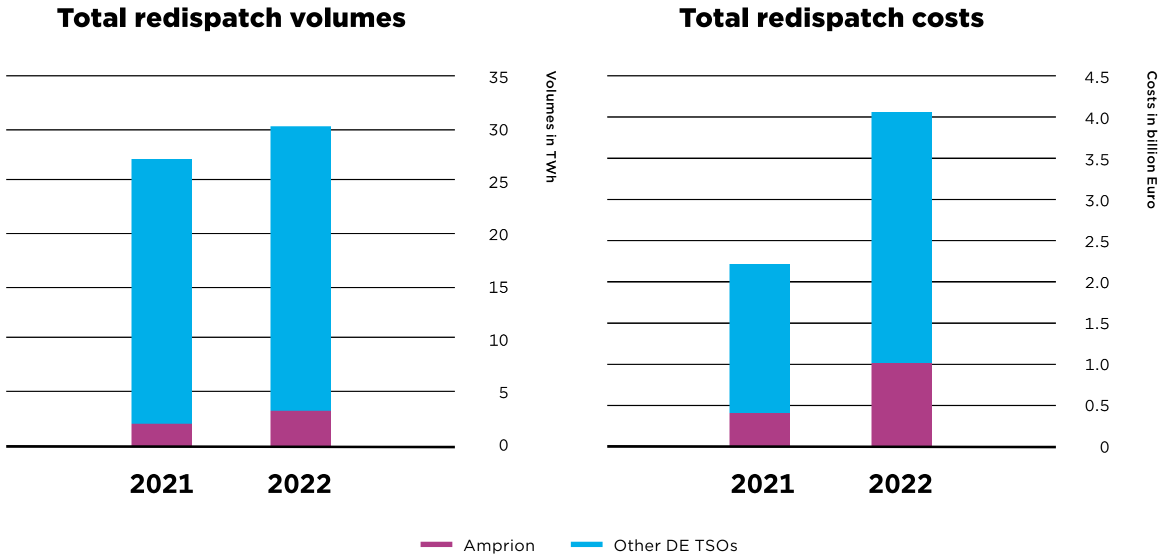


FIGURE 18 Total redispatch volumes and costs for Germany in 2022

29 In order to keep electricity generation and demand in balance, power generation has to be increased in other less constrained areas.

The two main driving forces of the German redispatch are usually wind infeed and the load as well as the supply situation in the south of Germany, with significant power flows into this southern area.

With more renewable generation, leading to higher load flows, more redispatch measures are required. Figure 19 illustrates the monthly redispatch volumes and costs for Germany with a focus on the Amprion share for the year 2022. In the first quarter of 2022, particularly high renewable generation especially in February combined with high loads caused a significant increase in redispatch volume and corresponding costs. Although this time period shows exceptionally high values, the development as such is not uncommon. Redispatch volumes and corresponding costs are usually higher in the winter months, in particular due to high wind generation. Simultaneously, there is a high demand and transit to southern Germany and other European countries (e.g. France due to the unavailability of nuclear power plants), which leads to high load flows and congestions. Another aspect leading to higher redispatch volumes and costs was the shutdown of three German nuclear power reactors by the end of 2021. Additionally, however, there were more developments in 2022 that caused extraordinarily high redispatch volumes and costs.

The commodity prices started to increase in 2021 and reached historically high levels in 2022, as explained at the beginning of the report. From a technical point of view, especially gas-fired power plants are used for redispatch due to their high flexibility and short reaction times to fluctuations. In addition, the unavailability of French nuclear power plants led to high load flows in the grid requiring more redispatch measures.

Besides the technical and economic reasons for the high redispatch volumes and costs, there were also formal changes affecting the handling and settlement of the German redispatch processes accompanied by the introduction of “Redispatch 2.0”. Therefore, these changes also affect the covered values for the redispatch volumes and costs, which makes them less comparable with previous year’s values. Firstly, it implies that throttling the supply of renewable energy plants due to feed-in-management now needs to be balanced with a positive counterpart by the TSOs. So far, throttling the supply of renewable energy plants was only accompanied by a financial compensation for the positive counterpart, whereas now this occurs by directly instructing a physical counterbalance. Hence, the additional counterpart increased the redispatch volume in 2022.

Secondly, the introduction of “Redispatch 2.0” entails that Grid Reserve power plants are now being used as the next most expensive provider in the market, which in turn resulted in an increased use of power plants operating in the Grid Reserve. Simultaneously, some power plants from the Grid Reserve and supply reserve took the opportunity provided by German emergency regulations to return to the market or remain in the market towards the end of the year.

Another aspect leading to an interim increase of redispatch volumes is the necessity for interim changes in the grid in order to realise new projects or reconstruction measures. Such corresponding short-term releases of grid elements lead to situations in which additional redispatch is required.

For the Amprion grid operation, congestions on the northern transmission lines (e.g. those in the Emsland region, which are very sensitive to wind power generation in northern Germany as shown in the Market Analysis chapter) continue to play a significant role.

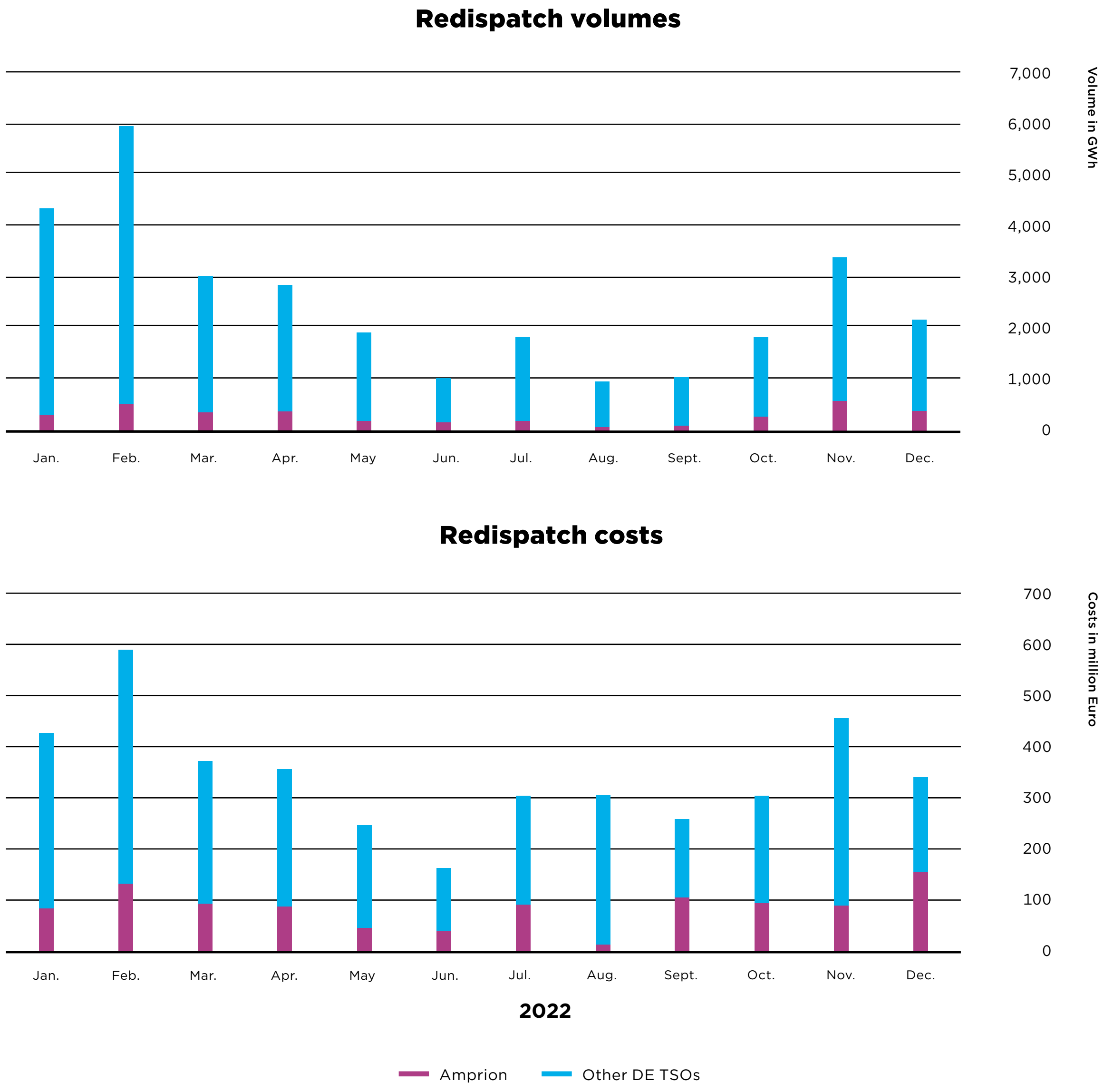


FIGURE 19 Total monthly redispatch volumes and costs[30] for Germany (including RE curtailment)[31]

30 Volumes are presented according to the instructing principle (i.e. in which control area power plants have been started in order to cure redispatch. Amprion does not instruct RE curtailment and this data is therefore missing in the volumes for Amprion). Costs are presented according to the requester principle (i.e. what costs did incur in order to cure the requested redispatch).

31 Disclaimer: The data shown in the graph may differ from redispatch figures published elsewhere (e.g. EMFIP report), as other sources sometimes contain assumptions for additional costs for recent changes in remuneration of remedial actions with larger power plants that have not yet been invoiced. The graph published here contains only the additional costs actually invoiced for remedial actions with larger power plants. The costs of RE curtailment also include assumptions in case of invoice delay.

FUTURE DEVELOPMENTS

For the transformation of the European energy system, new concepts for the integration of renewable offshore energy are necessary.

Further development and improvement of the existing electricity grid is the core business of TSOs, and in particular, increasing transmission capacity, reducing congestions and enhancing trading capabilities. In 2023 and beyond, Amprion will support cross-zonal trading by taking several additional measures.

The previous chapters have illustrated the main Core market trends and Amprion's operational activities in supporting current and future market integration.

This section provides a short summary of Amprion's planned future grid reinforcements and expansions. Strengthening our grid is an essential prerequisite for integrating renewables and alleviating the transmission constraints described in the Market Analysis chapter, which will accommodate further domestic and European electricity exchange. In the longer term, our plans will also pave the way for a fully integrated climate-neutral energy system by 2050, which is envisaged by the European Green Deal.

REINFORCEMENT AND EXPANSION OF THE EXISTING POWER GRID

Amprion is supporting the market by strengthening and extending its grid infrastructure by more than 2,500 kilometres in the next ten years. By the end of 2022, 616 kilometres of the transmission lines that Amprion had to build based on EnLAG[32] and BBPlG[33] had already been finished.

Two of Amprion's lighthouse projects are DC (direct current) links with 2 GW each from Emden in northern Germany to Osterath in western Germany and from Osterath to Philippsburg in southern Germany. These projects are referred to as the A-Nord project and the Ultranet project – one of the future cornerstones of the German transmission grid and the first DC multi-terminal project in Germany. Both will contribute to bringing offshore wind energy to the customers in central and southern Germany. While the A-Nord project is planned as an underground cable system, the Ultranet project is conceived as a hybrid system using the same pylons for DC lines in parallel to the already existing AC lines. Furthermore, Amprion is realising a DC corridor with 4 GW from northern Germany to western Germany. The project named Korridor B has already started the steps in the approval process and should be finished in the early 2030s. All projects are included in relevant legislation[34].

In total, Amprion is planning grid investments of more than 22 billion Euro over the next five years.

32 EnLAG = Energieleitungsausbaugesetz (Power Grid Expansion Act)

33 BBPlG = Bundesbedarfsplangesetz (Federal Requirements Plan Act)

34 The Federal Requirements Plan Act which lists the transmission projects that are legally defined through the German parliament. The German TSOs are obliged to implement these projects.

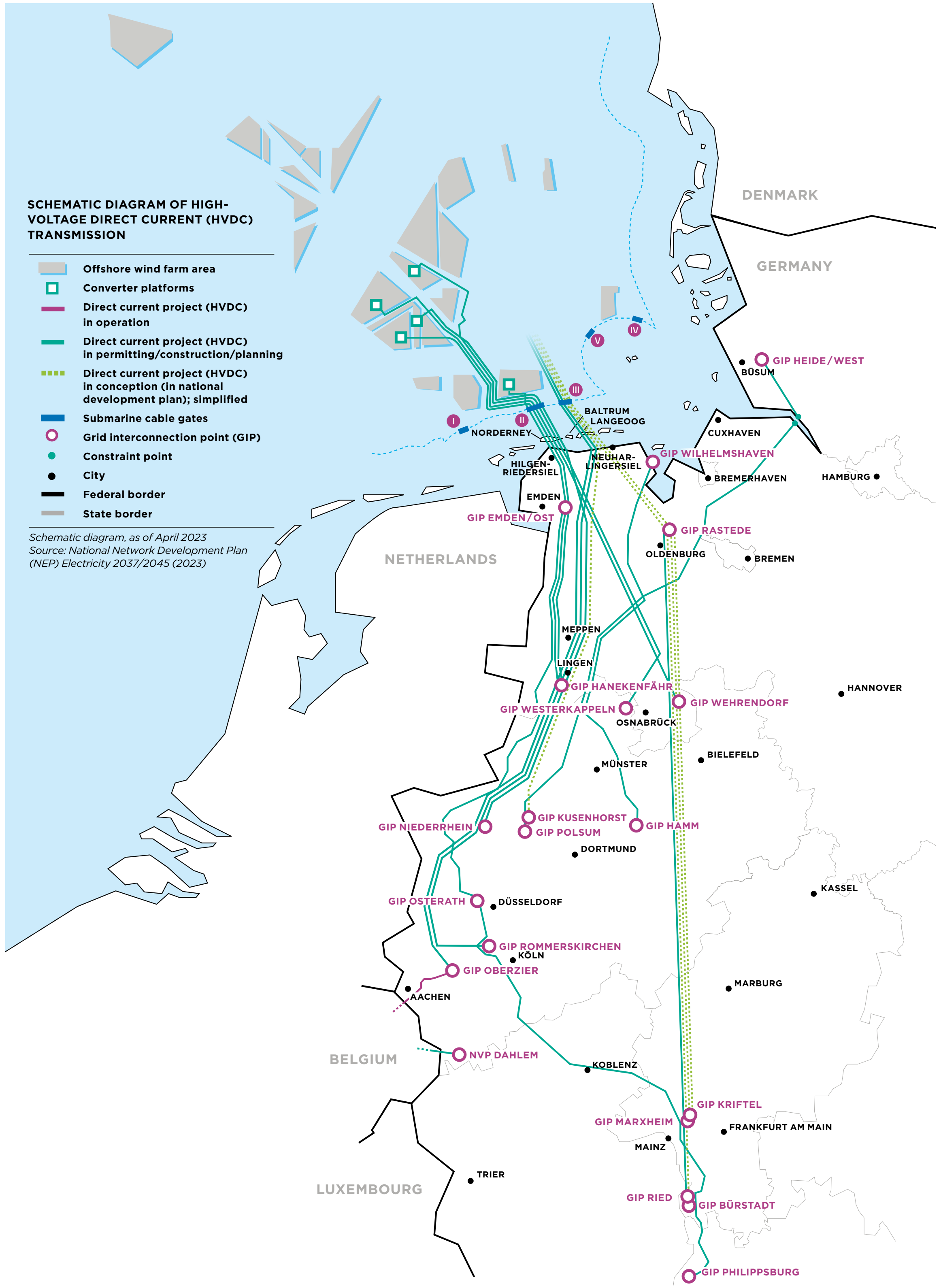


FIGURE 20 Schematic design of the integration of German offshore wind farms[35]

35 Source: netzentwicklungsplan.de

For Germany to achieve its climate targets, offshore wind farms should provide as much power as around 70 large coal-fired power plants by 2045. This requires not only new offshore wind farms, but also new lines connecting them to the transmission grid and with the customers. Amprion is currently building grid connection systems from the North Sea to the western parts of Germany. Beginning with its first offshore grid connection projects that will connect offshore wind to the transmission grid in Lower Saxony, Amprion will extend its offshore grid connection planning. In the current grid development plan 2023 (NEP2037/2045 (2023)), a total of 13 offshore grid connection systems are planned by Amprion to the south of Lower Saxony, NRW and Hesse (cf. Figure 20).

NEW OFFSHORE PROJECTS – HYBRID INTERCONNECTIONS

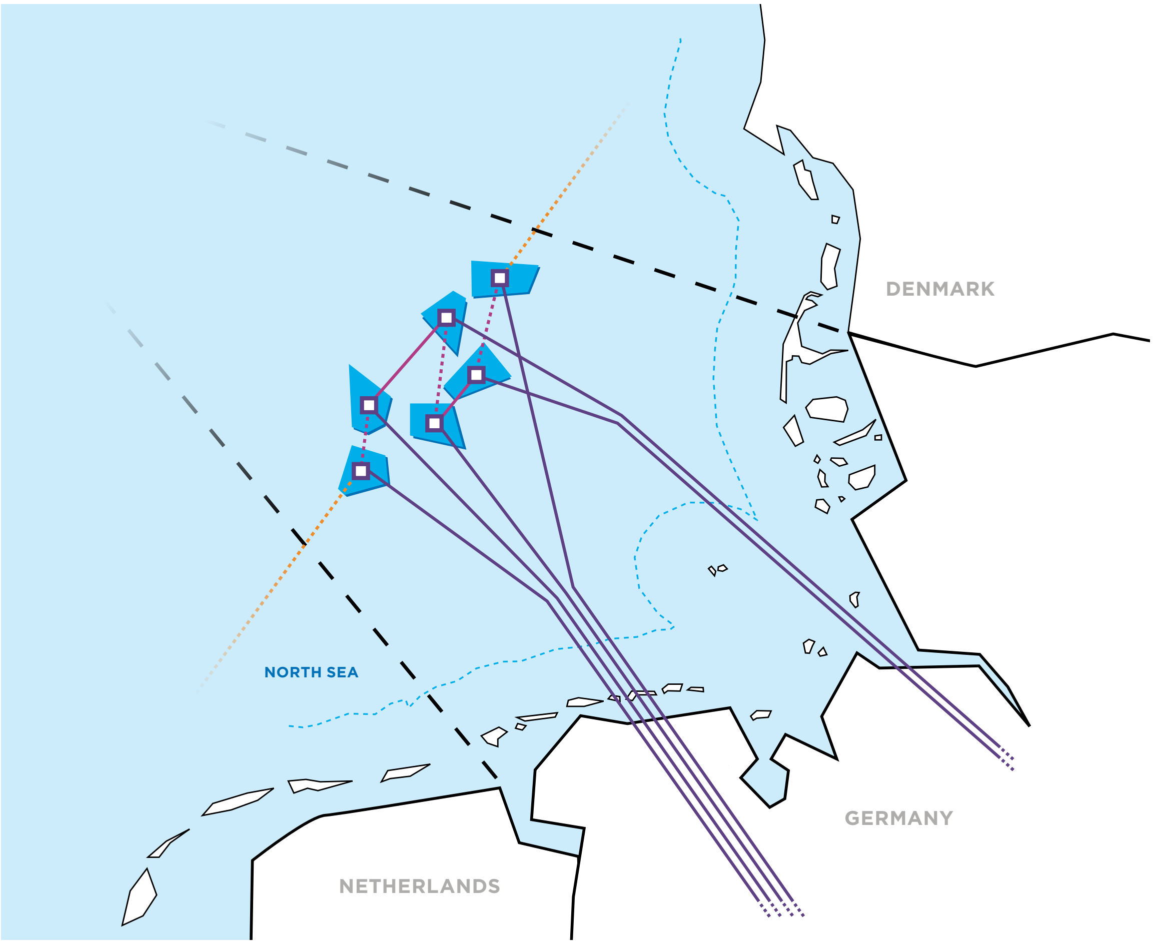
To achieve the climate targets, the European Commission envisages, in its EU Strategy on offshore renewable energy, an expansion of installed offshore wind capacity of up to 300 gigawatts (GW) by 2050. The European TSOs have the task to integrate this considerable and system-relevant amount of generation capacity into the adjacent transmission grid.

Nevertheless, after connecting the offshore generation to the shore, the wind power needs to be transmitted further from the coastal regions to the load centres in the central-west and south of Germany. This requires corresponding grid enhancement measures on land. In search for the most efficient solutions, near-load offshore grid connection points in Amprion's control area are considered more strongly in the German planning processes. Near-load grid connections are also especially promising candidates for innovative offshore interconnection concepts. These interconnections help to balance regions with different power needs as well as different wind resources, thus reducing infrastructure needs on land. In detail, the overarching concept that Amprion is pursuing is a step-by-step and modular offshore interconnection of point-to-point HVDC systems at sea. The significant added value of such offshore interconnections materialises itself both at a national and international level.

All in all, offshore interconnections increase the system redundancy and thus the overall availability of the interconnected systems for the offshore wind farms. In the case of unscheduled unavailability of the infrastructure, the wind energy flow can be re-routed through the interconnection to another onshore connection point. These set-ups will enable us as the grid operator to react flexibly to congestions occurring in the onshore grid when integrating high amounts of power generated by offshore wind farms. We can route the energy flows in such way that onshore grid bottlenecks can be effectively mitigated or resolved, thus reducing expensive and CO_2-intensive redispatch measures.

These benefits of a solely national offshore interconnection on congestion avoidance were investigated and considered in the current NEP2037/2045 (2023) for the first time. As a result, two offshore interconnections of national systems were identified and proposed:

- M272: Offshore interconnection between NOR-15-1 (grid connection point Kusenhorst) and NOR-16-1 (grid connection close to Büchen)
- M273: Offshore interconnection between NOR-17-1 (grid connection point Rommerskirchen) and NOR-18-1 (grid connection close to Wiemersdorf)



Converter platform
HVDC conncection to the onshore grid
National HVDC offshore interconnections
Potential further national HVDC offshore interconnections[36]
Potential further international HVDC offshore interconnections

FIGURE 21 Schematic design of the interconnection of German offshore wind farms in the North Sea[37]

36 Further national offshore interconnections are possible in the future if they are technologically feasible and economically efficient.

37 Source: bmwk.de/Redaktion/DE/Pressemitteilungen/2023/02/20230227-bmwk-und-uenb-veroeffentlichen-plaene-zur-vernetzung-von-offshore-windparks-in-der-nordsee.html

More renewable power generation can be integrated through the formation of international offshore interconnections.

In summary, the main contribution to overall welfare is achieved with international connections by expanding net transfer capacities between market areas and thus promoting cross-border trade and EU market integration. So, the major target of so-called hybrid interconnections is to fulfil two purposes: the integration of offshore wind and the increase of net transfer capacities between market areas. The impact of international offshore interconnection has been assessed in a separate study in parallel with NEP2037/2045 (2023). The study confirmed that more renewable generation can be integrated through international offshore interconnection. This reduces the overall European demand for thermal generation, ultimately reducing system costs and CO_2 emissions.

In the context of recent study findings and the Esbjerg Declaration "on the North Sea as the green power plant of Europe"[38], the offshore TSOs of the signing countries (Belgium, Denmark, Germany and the Netherlands) have developed a first grid topology for the North Sea. Germany has recently presented its first plans for this (cf. Figure 21).

In this vision of an initial offshore grid, Amprion offshore systems are considered for both national and international offshore interconnections. These will help to integrate offshore wind energy safely and efficiently into the energy system of the future, while reducing both grid operation and market costs.

NEW IMPETUS FOR ELECTRICITY MARKET DESIGN

Grid expansion is key to further integrating renewable energies into the European power grid. However, in order to achieve energy transition as fast and efficiently as possible the grid expansion needs to be accompanied by a future-proof market design. It must enable and support the extensive investments in renewable and back-up power generation plants, demand flexibility and power grids.

"Systemmarkt": An instrument to ensure the security of supply and to reach climate goals.

In order to accomplish the energy transition in Germany and Europe, there is a need for additional, fast-acting control instruments to accompany the expansion of renewables and the transmission grid. The "Systemmarkt" (systemmarkt.net) represents such an instrument and is able to consider the concerns of both the market and the grid. It is a market-design concept based on the well-proven Energy-Only-Market (EOM) complemented by elements comparable to a central capacity market and further extended by spatiality and ancillary services. By ensuring that sufficient secure power and necessary ancillary services are available in the long term, that these are available at the right places from a systemic perspective, and that they are also designed to leverage synergies, the "Systemmarkt" offers precisely these important control options.

38 Source: www.bundesregierung.de/resource/blob/974430/2040932/b357fa6726099a%200304ee97c3a64e411c/%202022-18-05-erklaerung-nordsee-gipfel-data.pdf?download=1

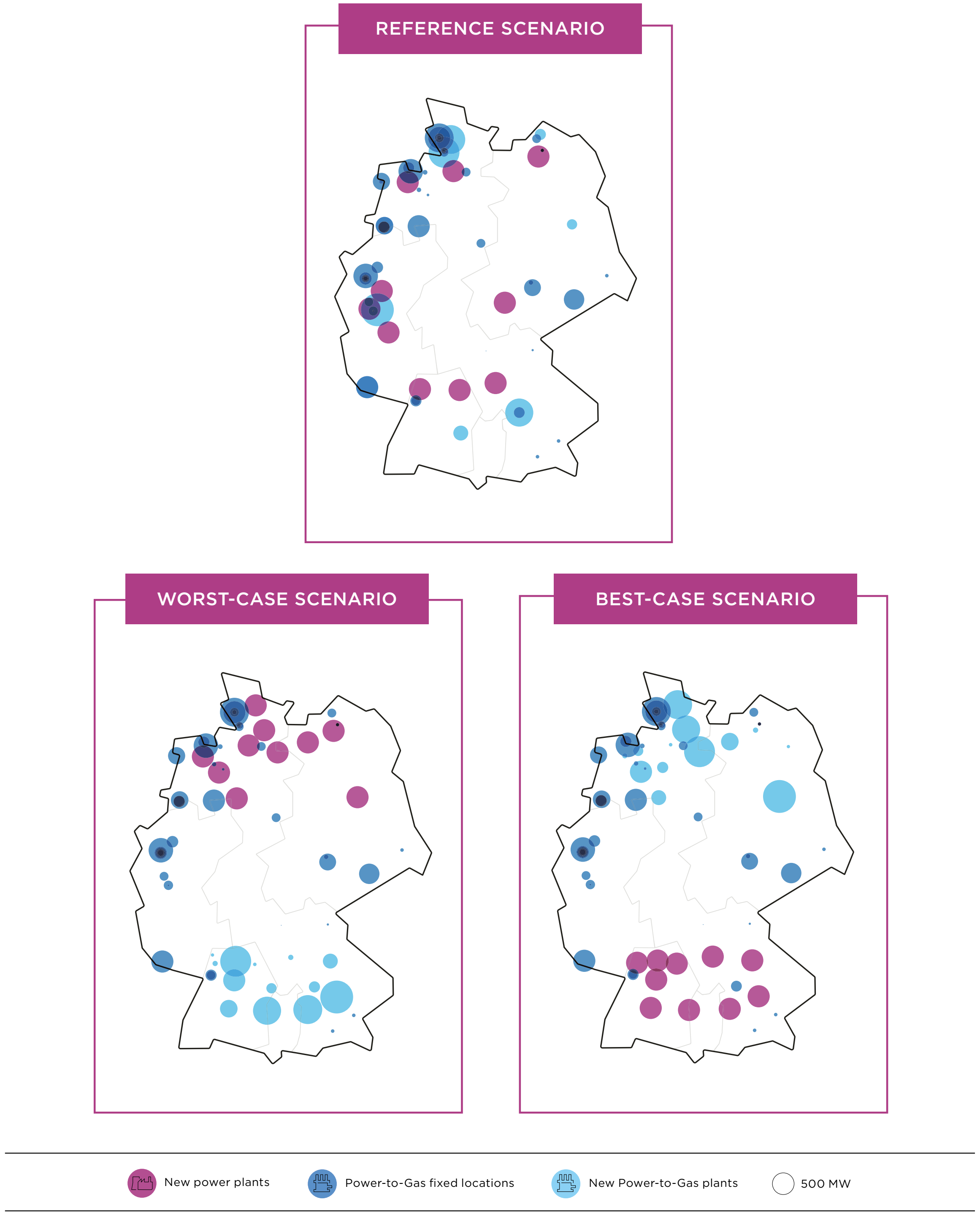


FIGURE 22 Investigated scenarios and locations of power and Power-to-Gas (PtG) plants

In this context, Amprion recently published a case study[39], which analyses the effects of locating power plants and new flexible loads in a way that serves the system. For this purpose, a sensitivity analysis was performed based on a reference scenario for 2030 and a worst-case and best-case scenario was generated under the reallocation (system-serving or system-inefficient) of 5 GW of flexible generation and 4.1 GW of flexible loads (Power-to-Gas (PtG)), which is illustrated in Figure 22. The core result of the case study is that locating even a small portion of flexible generation and loads to serve the system can reduce future redispatch volumes and costs by about 20–25%. In particular, the localisation of PtG plants has a relevant effect. Locating power plants, on the other hand, secures redispatch potential in Germany, in particular, and thus significantly reduces cross-border redispatch requirements.

The study shows the added value of allocating new technologies in Germany in a way that serves the grid and the system. However, a random location decision for the plants was still made, merely with a local focus. Based on a detailed grid analysis, further optimisation potentials could be expected in order to further reduce the need for redispatch. In addition, the number and installed capacity of the plants was not optimised either. The newly located plants represent only a small part of the expected addition of new flexible generators and loads. Again, there is a corresponding potential for optimisation with respect to the capacity to be located locally.

Local long-term capacity incentives are an appropriate alternative to smaller bidding zones.

For the example of Germany, the obvious solution for local incentives would be the splitting of the common bidding zone. However, already the discussion about the introduction of a bidding zone split leads to high levels of uncertainty in the market. While for many years the energy sector discussed a "missing money problem" at the energy-only market (EOM), recent developments show that we are currently talking much more about a "missing certainty problem". The basis for investments in capital-intensive power generation assets are long-term foreseeable framework conditions[40]. In view of the ambitious national and European climate change mitigation goals up to 2030, we as a society can therefore not afford this uncertainty at present. There is a need for massive investments in the expansion of the transmission grid, renewable energies, the decarbonisation of industry, back-up capacities and demand flexibility in the coming years, and this requires stable investment conditions. Consequently, the question arises as to whether other measures may be better suited to manage the allocation of new loads and generators. Local long-term capacity incentives could be a sensible alternative in this respect, providing a high degree of planning and investment security.

39 Available at: systemmarkt.net/Aktuelles-und-Events/

40 It is worthwhile mentioning that the introduction of a German bidding zone split would come along with further investment-related challenges going beyond the uncertainty issue. For example, several Power Purchase Agreements (PPAs) are currently planned between offshore wind farm developers and large industrial companies in Germany. If the wind farms, which are to be constructed under the financial agreement of a PPA, are to be located in a different bidding zone than the participating industrial consumer, an exchange of electricity between them would only be possible to a limited extent. Consequently, a bidding zone split would raise the question of who must bear the risk of unavailable transmission capacity. This in turn could be a barrier to investments in new offshore wind farms to be constructed under the financial framework of a PPA.

CONCLUSION AND OUTLOOK

Grid expansion accompanied by an efficient market design is key to the further integration of renewable energies and the European energy transition.

Looking back at the last three years from 2020 to 2022, it was an exceptional time full of challenges for our society. Each year on its own was a special year. First the Covid-19 pandemic hit the entire world in 2020, causing turbulences in every aspect of social life and the global economy. After an easing of the situation, conditions worsened drastically again at the end of 2021 in anticipation of the following events in Ukraine. Then in February 2022, after the Russian invasion of Ukraine and the political response of the EU, gas and electricity prices climbed to an all-time high in Europe in summer 2022. This has led to exceptional market interventions by the European Commission and was the starting point for a new fundamental discussion of the future market design in Europe.

Unexpected unavailability of several French nuclear power plants triggered a new record of electricity imports from Germany.

The report shows that gas and electricity prices increased significantly since March 2022, reaching an all-time high in August. Although, the progress in European market integration with the involvement of TSOs has helped to mitigate the negative impact of the energy crisis. This progress and positive impact on market integration should also be kept and even improved in the future. For that reason, Amprion is planning grid investments of more than 22 billion Euro over the next five years.

As a result of the whole situation on the energy markets, the European Commission has determined to even accentuate their climate goals by raising the targeted share of renewable energies in the EU energy mix up to 45% in 2030. However, this acceleration requires concrete measures, which must unleash their effects already this year. Despite the current geopolitical situation, the latest developments on the European electricity market such as the go-live of the Core project, the progress made in international trade and the ongoing political debate about the future of the market design make us feel confident and optimistic that these goals can be reached. However, this requires fast and resolute decisions to be made by national and European policymakers.

Now more than ever, a suitable market design able to push the expansion of renewable and new back-up capacities is needed in order for Europe to become more independent from energy imports.

In the end, our plans towards a carbon-neutral energy system are still valid and were even strengthened throughout the year. At the same time, we need to speed up the transformation even more. In order to drive forward decarbonisation and cope with Europe's greater geopolitical independence, holistic and timely solutions are needed. Amprion sees it as its responsibility to develop holistic solutions addressing an accelerated grid expansion, European market integration and new solutions such as Amprion's "Systemmarkt" in order to actively shape the transition of the energy system.

LIST OF ABBREVIATIONS

ACER	Agency for the Cooperation of Energy Regulators
aFRR	Automatic Frequency Restoration Reserve
ATC	Available Transfer Capacity
CCR	Capacity Calculation Region
CNECs	Critical Network Elements and Contingencies
CSP	Common Service Provider
CWE	Central and Western Europe
DA	Day-Ahead
DACC	Day-Ahead Capacity Calculation
DAVinCy	Day-Ahead Validation of Capacity
DC	Direct Current
EB	Electricity Balancing
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
FB MC	Flow-Based Market Coupling
FRR	Frequency Restoration Reserve
IDAVinCy	Intraday Day-Ahead Validation of Capacity
IGCC	International Grid Control Cooperation
IVA	Individual Validation Adjustments
LNG	Liquefied Natural Gas
LTCC	Long-Term Capacity Calculation
MARI	Manually Activated Reserves Initiative
mFRR	Manual Frequency Restoration Reserve
MinRAM	Minimum Remaining Availability Margin
NRA	National Regulatory Authority
PICASSO	Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation
PPA	Power Purchase Agreement
PtG	Power-to-Gas
RAM	Remaining Available Margin
RAs	Remedial Actions
RCCs	Regional Coordination Centres
RDCT	Redispatch and Countertrading
RE	Renewable Energy
TERRE	Trans European Replacement Reserves Exchange
TSO	Transmission System Operator

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