AMPRION MARKET REPORT 2020

DEVELOPMENT OF THE MARKET AND GRID SITUATION
2015–2019

CONTENTS

AMPRION MARKET REPORT 2020

EXECUTIVE SUMMARY

As the backbone of the electricity system, transmission system operators (TSOs) play an important role in the success of the European energy transition as well as in the implementation of a functioning internal energy market. Tackling climate change and achieving the objectives of the Paris Agreement poses significant challenges for the entire European energy system. On a domestic level, the German energy system is undergoing an unprecedented transformation. Electricity production from nuclear energy and coal will be phased out while an increasing share of renewable energies is integrated into the system. Even in times of such a dynamic and changing environment, TSOs are ensuring a 24/7 electricity supply and are thus enabling the energy transition. Efficient cooperation is a key prerequisite for this, which is why TSOs are jointly and cooperatively working around the clock to ensure a secure network, promoting security and cross-zonal trade within the entire European electricity system.

Amprion is, and has been for decades, an integral part of this cooperation. 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 our neighbouring TSOs, National Regulatory Authorities (NRAs), ACER (the Agency for the Cooperation of Energy Regulators), power exchanges, a vast number of market parties and our association ENTSO-E (European Network of Transmission System Operators for Electricity). **In a nutshell, close mutual cooperation is in our DNA**.

One example for successful market integration – which this report explains in further detail – is flow-based market coupling (FB MC). FB MC accommodates a more detailed consideration of the technical limits of the electrical transmission networks. This leads to an optimal use of the available transmission capacity for cross-border trade, without jeopardising grid security.

European market integration relies on a strong network for electricity exchanges across borders. Our grid is strongly interconnected with other transmission grids within Germany and also with the Netherlands, Luxembourg, France, Austria and Switzerland. Furthermore, Amprion and Elia are currently building ALEGrO (Aachen Liège Electricity Grid Overlay), the first interconnection between Germany and Belgium.

This report provides evidence of the significant benefits resulting from our strong and steadily enhancing cooperation. Given our central location in Central Western Europe (CWE) our contributions to the overall European Electricity Market mainly focus on this CWE area.

IN MORE CONCRETE TERMS, THE FOLLOWING DEVELOPMENTS INDICATE THE ADVANCEMENT OF EUROPEAN MARKET INTEGRATION:

- Price convergence in the day-ahead markets increased by a further 10% in 2019, reaching 42% as illustrated by the Figure below. In other words, in almost every second hour day-ahead prices in CWE have been equal. This provides evidence for a vastly integrated CWE market which is continuously increasing.[1]

Increasing number of hours with unlimited CWE trading

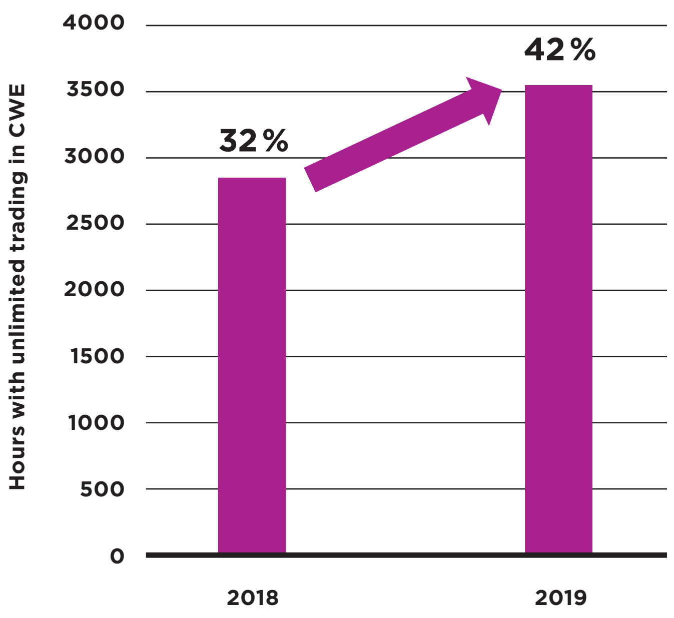


Figure: Development of hours per year with unlimited CWE trading 2018–2019

- Capacities provided to the CWE market remain constantly high, supporting a higher market liquidity. Amprion supports this trading by applying low reliability margins on its network elements for the flow-based capacity calculation in CWE: while the average reliability margin for CWE is 13%. Amprion applies only 9% on average.[2]

- TSOs are enablers of the European energy transition and drivers of the entire European energy market integration. Amprion is highly committed to supporting cross-border trades. Hereby, the open and transparent publication of critical network elements gives an indication of the level of trading possibilities within the CWE region. The Figure below provides evidence of the steadily declining share of Amprion's internal network elements constraining the market. In other words: by decreasing grid constraints in its control area, Amprion enables more trading in CWE.[3]

[1] See Section 3.2 for further details
[2] See Section 3.1 for further details
[3] See Section 3.2 for further details

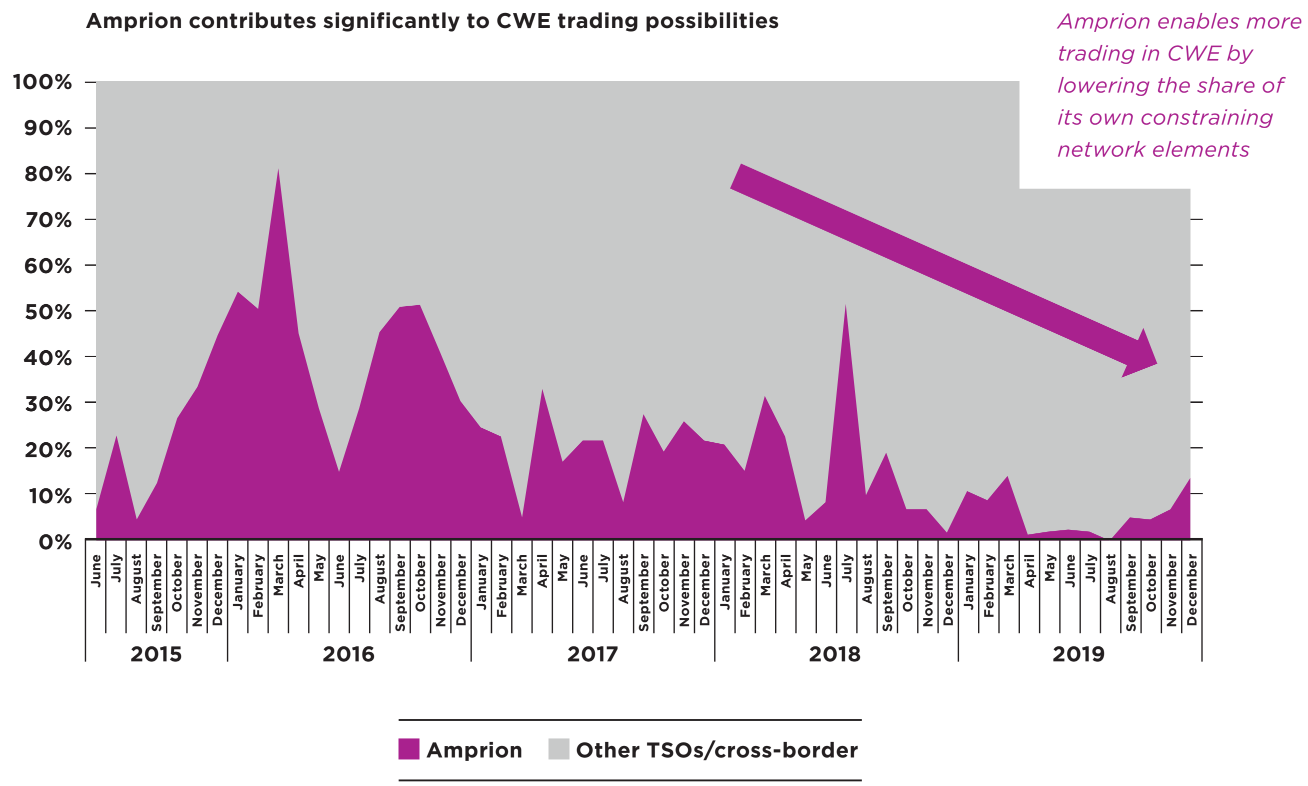


Figure: Decreasing share of Amprion's market-constraining internal network elements, i.e. relative frequency of active critical branches per hour from 06/2015–12/2019
Please note that only internal network elements are shown

Facilitating the described, high electricity exchanges across CWE and Europe comes at a cost. In particular, during times of high infeeds from renewables (RES) and high electricity exchanges with our neighbours, Amprion's centrally located network is highly utilised. This requires the application of costly remedial actions in order to alleviate the congestions induced by a high grid utilisation. Our report analyses Amprion's remedial actions applied during 2019. Some specific lines in the north of our control area are influenced by offshore wind farm injections. Our cross-border lines are impacted by CWE trading and the high capacities we offer to the market. We need to apply remedial actions in order to alleviate those network elements, keeping their operation within the technical safety limits.

A further increase in capacity for electricity exchanges within Europe will increase the costs for remedial actions. This will become particularly relevant with the implementation of the 'Clean Energy for All Europeans Package' provisions related to minimum capacity targets[4].

[4] As one of the main provisions, at least 70% of the capacity of internal and cross-zonal critical network elements has to be made available for cross-zonal trading from 1 January 2020. By using extension clauses, member states can increase the required minimum trading capacity stepwise until the end of 2025.

In summary, Amprion's market and system operation activities in cooperation with several other partners and institutions has been continuously enabling and enhancing European market integration within CWE and beyond. Our investments in new interconnectors and internal lines have increased the trading possibilities by providing further physical transmission capacity (which corresponds to a decrease in grid constraints and an increase in trading capacity in the CWE market). Further investments are either planned or already in the process of being realised. All of this shows Amprion's strong commitment and support for the European market.

AMPRION MARKET REPORT 2020

INTRODUCTION

Today, Amprion's grid is interconnected with other transmission grids within Germany and also with the Netherlands, Luxembourg, France, Switzerland and Austria. With ALEGrO, the first interconnection between Germany and Belgium is currently under construction.

This report provides evidence of the significant mutual benefits resulting from Amprion's strong and steadily enhanced cooperation with TSOs, power exchanges and market parties of the CWE region and beyond.

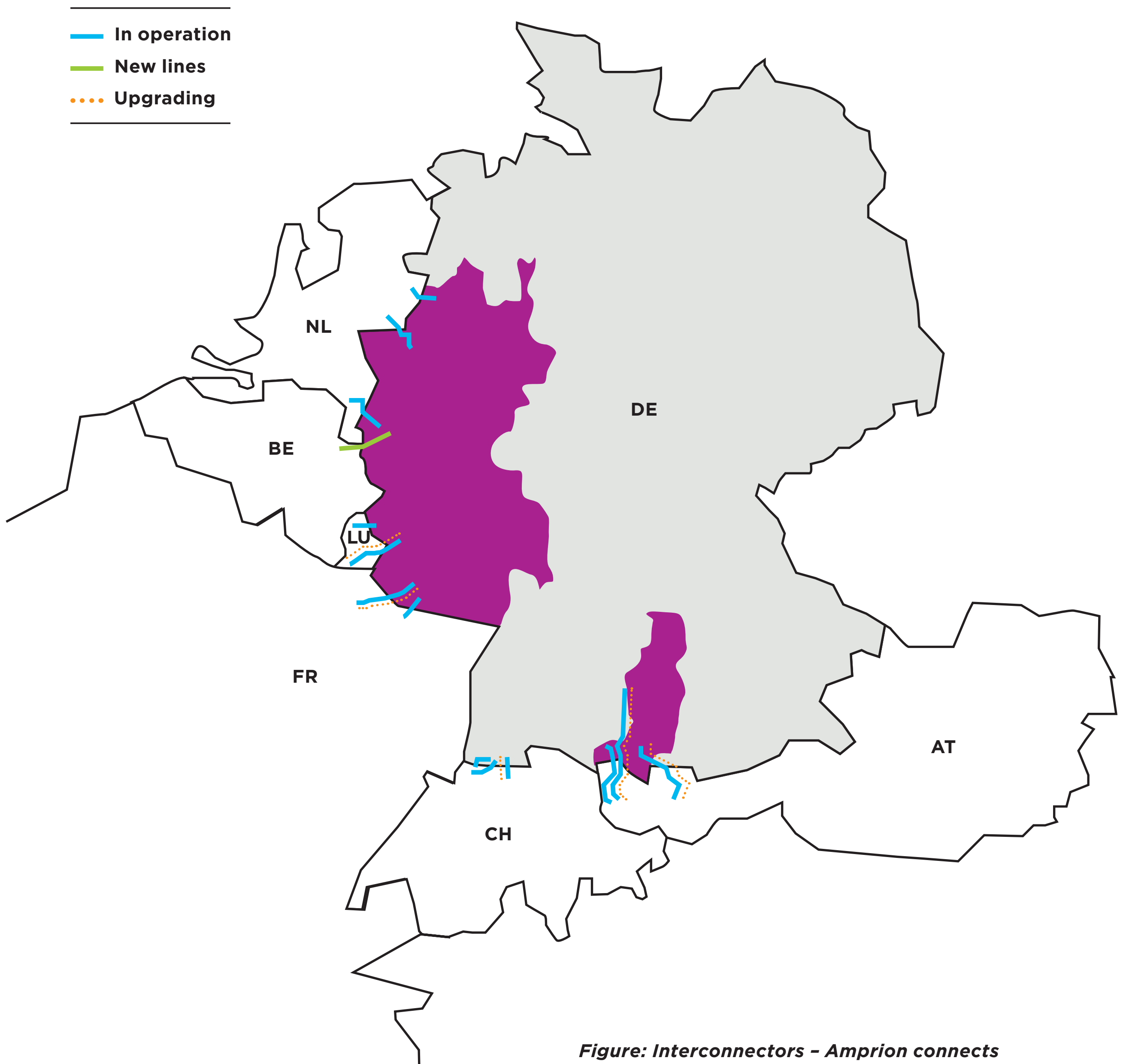


Figure: Interconnectors – Amprion connects electricity markets across borders

AMPRION MARKET REPORT 2020

1. CURRENT TREND IN GENERATION ADEQUACY IN EUROPE

DECREASING SHARE OF CONVENTIONAL GENERATION IMPACTS SYSTEM SECURITY AND WILL SIGNIFICANTLY INCREASE GERMANY'S FUTURE IMPORT NEEDS.

While electricity demand has remained relatively stable over time, conventional generation capacities have decreased in all CWE countries in recent years. This trend is expected to continue in the coming years. In 2019, as in the past years and decades, a continuous balance between electricity supply and demand has always been guaranteed in Germany due to sufficient conventional generation capacity. However, the policy trend towards carbon-neutral electricity production and further market developments have led to a decrease in conventional generation capacity. In previous times, conventional power plants provided the flexibility of continuously adjusting their generation to the overall demand. With a decreasing share of conventional generation and an increasing feed-in of weather-dependent renewable energies such as wind and PV, this flexibility will have to be provided by other sources.

The more concrete terms and conditions for the decommissioning path of conventional coal generation capacities were decided by the German Coal Commission in 2019. The Commission recommends a shutdown of approximately 12.5 GW coal capacity by 2022, as compared to the end of 2017, and a further shutdown of 13 GW by 2030.[5] All coal generation capacities are to be closed by 2038, in order to mitigate CO_2 emissions in accordance with the Paris Climate Agreement. The recommendation has already been put into a draft law ('Kohleausstiegsgesetz') setting an explicit and binding target for the German coal phase-out. In parallel, the last nuclear generation capacities will be shutdown by 2023, which leads to a further decrease in conventional capacity by 10.8 GW as compared to the end of 2017.[6]

Similar efforts to achieve the Paris Climate Agreement and to shut down conventional capacities are being made in other countries in Europe. Exemplarily, France and Great Britain have announced a coal phase-out by the end of 2022 and 2024 respectively, which would reduce conventional generation by 3 GW in France[7] and by 5.3 GW in Great Britain[8]. Besides that, a nuclear phase-out by 2025 is discussed in Belgium, potentially reducing conventional generation by 5.9 GW[9]. In the interconnected European electricity system, such individual changes in the generation capacities in different countries have a substantial impact on the overall European security of supply during scarcity situations.

[5] See Abschlussbericht Kommission „Wachstum, Strukturwandel und Beschäftigung“: https://www.bmwi.de/Redaktion/DE/Downloads/A/abschlussbericht-kommission-wachstum-strukturwandel-und-beschaeftigung.pdf?__blob=publicationFile&v=4

[6] See Atomgesetz: https://www.bmu.de/themen/atomenergie-strahlenschutz/nukleare-sicherheit/rechtsvorschriften-technische-regeln/grundgesetz-atomgesetz/

[7] See France to close Havre coal-fired power plant in April 2021: https://www.reuters.com/article/us-france-electricity-coal/france-to-close-havre-coal-power-plant-in-april-2021-idUSKBN1Z91IO

[8] UK brings forward coal phase-out to 2024: https://www.argusmedia.com/en/news/2064277-uk-brings-forward-coal-phaseout-to-2024

[9] See Belgium's Doel nuclear plant may close early following court ruling: https://www.neimagazine.com/news/newsbelgiums-doel-nuclear-plant-may-close-early-following-court-ruling-7819025

1.1 DEVELOPMENT OF THE SECURITY OF SUPPLY SITUATION FOCUSING ON GERMANY: LEISTUNGSBILANZBERICHT OF THE FOUR GERMAN TSOS

German TSOs' resource adequacy report reveals that Germany's import needs will significantly increase in the next few years, possibly up to 7.2 GW in 2022.

In addition to ENTSO-E's analyses (see Section 1.2), the four German TSOs publish a resource adequacy report every year. This national report focuses on the German generation system and examines for one critical situation (i.e. high load with simultaneously very low feed-in from wind and PV) whether the load in Germany can be covered by the national generation system. In the event that national capacities are not able to cover the load completely, Germany will be dependent on imports. A negative remaining capacity does not necessarily result in load shedding. However, it is not analysed whether the imports in the assumed situation are reliably available. Furthermore, no statement is made about the probability of occurrence of the situation assumed in the report.

The central result of the recent 'Leistungsbilanzbericht' 2019[10] is shown in the following Figure 1. It illustrates the remaining capacity for the reference dates for the years 2019 to 2022, taking into account the grid reserve power plants as well as the lignite reserve. The chosen reference dates consider a potential situation under system stress with high load and simultaneously very low feed-in from wind and PV (so-called 'Dunkelflaute'[11]). The remaining capacity increases to 2.9 GW in January 2020 due to the commissioning of the hard-coal-fired power plant unit Datteln 4 and then decreases to -7.2 GW in 2022. This means that in the assumed critical situation (i.e. high load – low RES feed-in) in January 2022, Germany will be dependent on imports of 7.2 GW to fully cover the load in Germany. This import need is below the interconnector capacity to neighbouring countries. However, the focus of the analysis should not be on absolute figures but rather on the trend of the development. The figures show that Germany's dependence on imports will increase significantly in the future and the reliability of imports will play an increasingly important role.

[10] See detailed results: https://www.amprion.net/Netzjournal/Artikel-2020/Leistungsbilanzbericht-Den-Extremfall-im-Blick/
[11] Similar situations already occurred, e.g. in January 2017

AMPRION MARKET REPORT 2020

Remaining capacity in Germany during system stress events

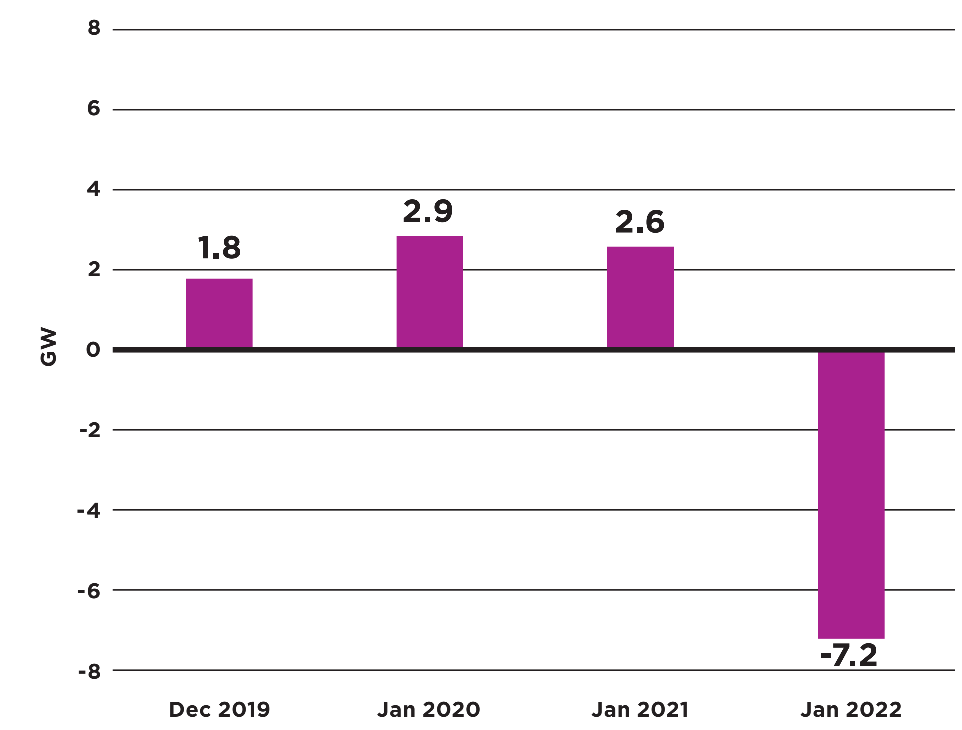


Figure 1: Remaining capacity in Germany incl. reserves (scenario: path of coal phase-out considered)[12]

1.2 DEVELOPMENT OF THE SECURITY OF SUPPLY SITUATION FOCUSING ON EUROPE: MIDTERM ADEQUACY FORECAST

ENTSO-E Adequacy Forecast expects 0.3 hours in 2025 during which electricity demand cannot be covered in Germany.

ENTSO-E is assessing the security of supply in Europe and identifying possible deficits on an annual basis in its Midterm Adequacy Forecast report (MAF). This is done by simulating the European interconnected power system looking up to ten years ahead. Input data is collected from all European TSOs based on their best knowledge including national policy targets such as the coal phase-out in Germany.

The MAF 2019[13] was published in November 2019 focusing on two target years, 2021 and 2025. The main indicator for assessing the security of supply is the so-called Loss of Load Expectation (LOLE). The LOLE is defined as the expected number of hours in a year during which the demand cannot be covered by all generating capacities.

[12] See detailed results: https://www.amprion.net/Netzjournal/Artikel-2020/Leistungsbilanzbericht-Den-Extremfall-im-Blick/
[13] See Executive Summary of MAF 2019: https://www.entsoe.eu/outlooks/midterm/

Figure 2 shows the LOLE results for both target years for Europe overall, while the LOLE for Germany is marked in red.

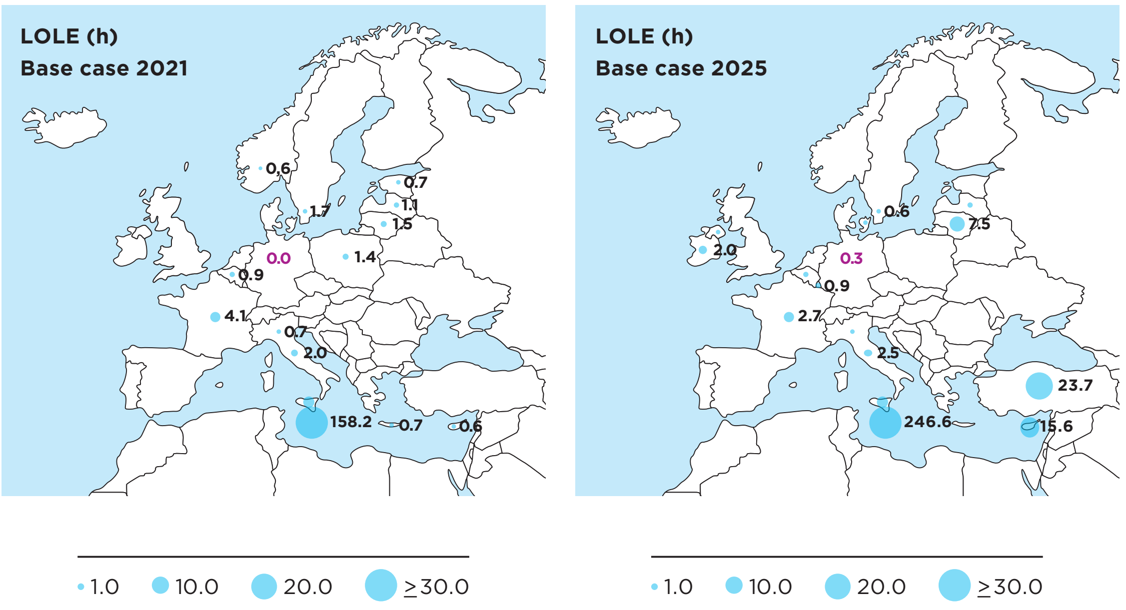


Figure 2: Comparison of LOLE values between 2021 and 2025 in the base case scenario. Zones with missing circles have LOLE values below 0.5 h/a (except for Germany)

For 2021, no LOLE is simulated for Germany, which indicates the expectation of a fully secured electricity supply during this year. This changes in 2025 where load losses are expected during 0.3 hours of the year. The LOLE value of 0.3 h/year still meets the national reliability target of 5 h/year as defined by the German Federal Ministry for Economic Affairs and Energy in their national security of supply monitoring report.[14] In 2025, however, the full coal phase-out will not yet have been accomplished. Its full impact on the German and European security of supply will therefore only take effect in the years beyond 2025, which are not simulated in the current MAF. The MAF also contains sensitivity analyses for Germany with a higher LOLE level under more conservative assumptions[15].

Figure 2 also indicates a more constrained security of supply situation in other European countries, some of which are not meeting their national reliability targets in the simulations.

The mutual interdependencies in the interconnected, European electricity system also emphasise the importance of considering changes in the power plant park in neighbouring countries when assessing the security of supply in a highly interconnected country such as Germany.[16]

[14] See Definition and monitoring of security of supply on the European electricity markets: https://www.bmwi.de/Redaktion/EN/Publikationen/Studien/definition-and-monitoring-of-security-of-supply-on-the-european-electricity-markets-from-2017-to-2019.html

[15] The number of hours with load loss in a more critical once-in-20-years occurrence, which is also determined in the MAF report, rises to 1 h/a in 2025. In the low-carbon sensitivity, LOLE increases to 0.6 h/a in Germany due to a further reduction of coal-fired power plants in other countries.

[16] See detailed results, sensitivities and input data: https://www.entsoe.eu/outlooks/midterm/

2. ELECTRICITY MARKETS IN EUROPE

THE CONCEPT OF MARKET TIME FRAMES AND FLOW-BASED MARKET COUPLING.

Electricity is a non-storable good which needs to be produced at the point at which it is consumed in real time. Trading of electricity takes place before and after this point in time. Figure 3 gives an overview of the current trading time sequence in wholesale and balancing markets. In sequential order, energy can be traded one or more years before the delivery (Forward and Futures Markets) up to the day after the actual delivery. While in the day-ahead market energy is traded one day before real time, the intraday market enables market participants to correct their nominations on the delivery day itself.

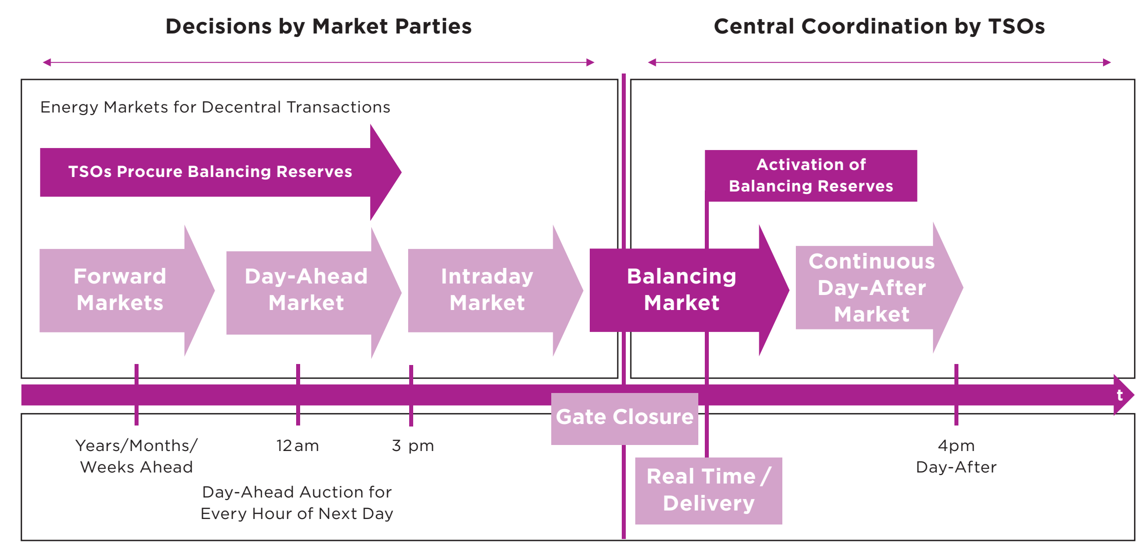


Figure 3: Overview of different time frames of the wholesale and balancing markets

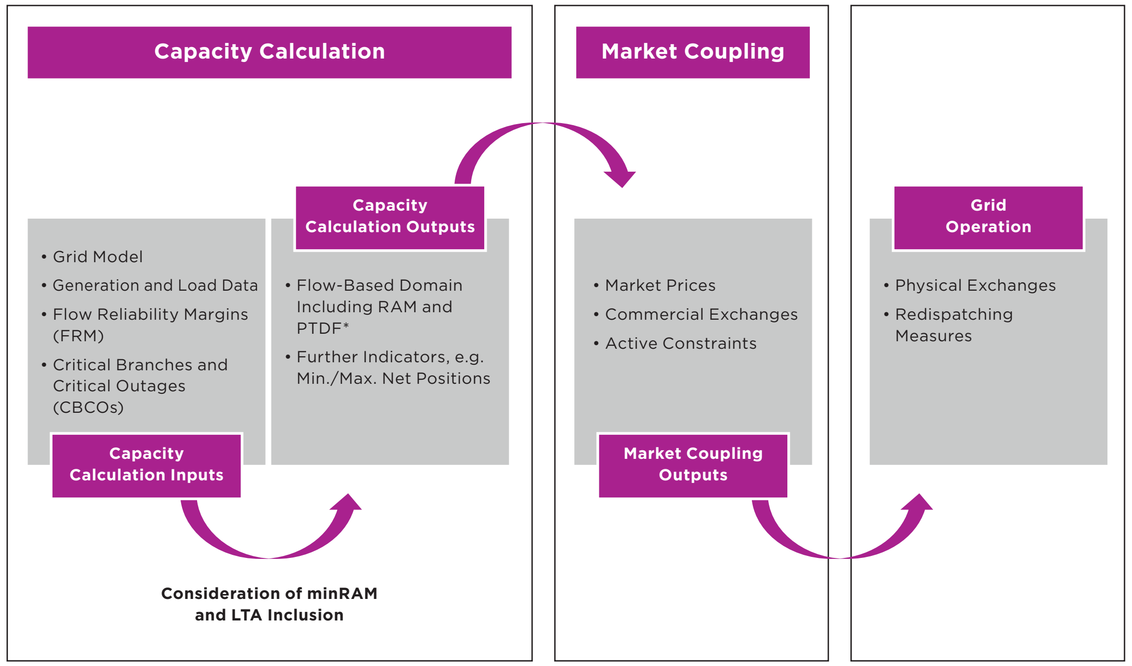
2.1 FORWARD AND FUTURES MARKETS

Forward and Futures products allow market participants to hedge themselves against short-term price uncertainties. The markets for these long-term products start from years before up to days before the actual delivery. Forwards are usually traded over-the-counter (OTC) between two involved parties without being standardised, whereas futures are standardised contracts which are traded on power exchanges.

2.2 DAY-AHEAD MARKET AND FLOW-BASED MARKET COUPLING

The main focus of this report is the day-ahead time frame and the Flow-Based Market Coupling. Relevant inputs and outputs of the FB MC as well as the subsequent grid operation are illustrated in Figure 4.

In a zonal electricity market, the available capacity between bidding zones is determined by translating physical transmission constraints into commercial transaction constraints (see step 'Capacity Calculation' in Figure 4). These simplified commercial transaction constraints are then considered in the market clearing algorithm determining market prices and cross-zonal exchanges between participating bidding zones (cf. step 'Market Coupling' in Figure 4). Congestions occurring after the market coupling require redispatching measures, which are coordinated by affected TSOs during real-time grid operation (cf. step 'Grid Operation' in Figure 4).



* RAM: Remaining Available Margins, PTDF: Power Transfer Distribution Factors

Figure 4: Overview of flow-based capacity calculation and market coupling

AMPRION MARKET REPORT 2020

MAIN FEATURE OF FLOW-BASED MARKET COUPLING: DIRECT CONSIDERATION OF PHYSICAL TRANSMISSION CONSTRAINTS IN THE MARKET

The main enhancement of the FB MC compared to the NTC[17]-based market coupling is the (direct) consideration of physical transmission constraints in the market clearing algorithm. Accordingly, all critical network elements relevant for cross-zonal exchanges (so-called critical branch critical outage combination (CBCO)) are taken into account in the market clearing, bringing commercial transactions closer to the physical reality.

The impact of cross-zonal commercial transactions (i.e. change of bidding zones' net positions) on flows through relevant critical network elements is determined by multiplying them with so-called Power Transfer Distribution Factors (PTDFs). In other words, the PTDFs describe how much electricity flows through particular network elements if certain (incremental) cross-zonal commercial transactions are taking place. In CWE, only network elements that fulfil a cross-zonal relevance criterion[18] are considered to be a potential constraint in the market coupling algorithm (as so-called CBCOs).

Flow on critical network element induced by cross-zonal trade = PTDF · bidding zone net position

The flows through those critical network elements induced by cross-zonal trade are then limited to the Remaining Available Margin (RAM) on the elements. In other words, the RAM is the margin which is available on critical network elements for commercial transactions or cross-zonal trade in CWE. Hereby, the RAM is derived from technical parameters and the system state within the flow-based capacity calculation process.

The RAM[19] is determined by subtracting a reference flow (Fref), a Flow Reliability Margin (FRM) and a Final Adjustment Value (FAV)[20] from the maximum allowable flow (Fmax).

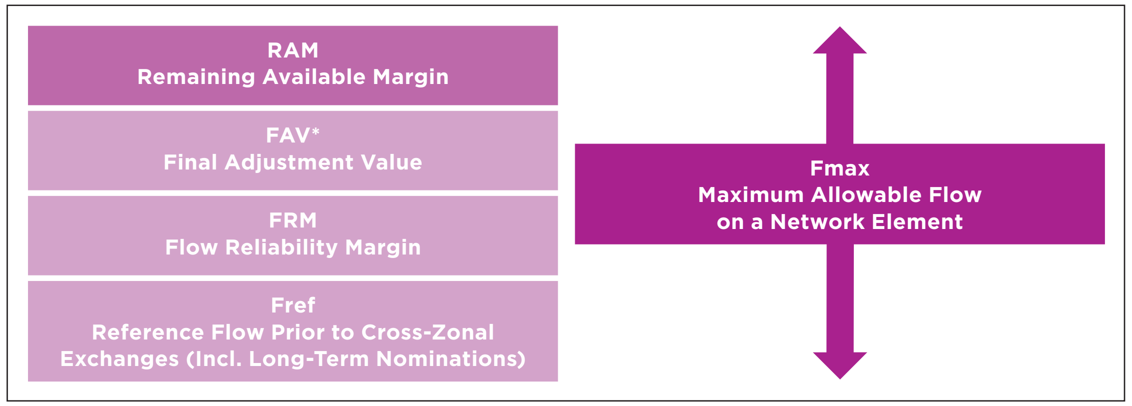
RAM = Fmax – Fref – FRM – FAV

[17] Net Transfer Capacity (NTC)

[18] Usually a minimum zonal PTDF of 5%

[19] Prior to minRAM adjustment and inclusion of long-term allocation (LTA)

[20] FAV can be used by TSOs to reduce or increase the RAM on a critical network element for very specific reasons, i.e. system security reasons. Amprion completely removed its FAV values in the beginning of 2017, thus dispensing with a further reduction of the RAM.



* FAV is no longer used by Amprion

Figure 5: Determination of the maximum allowable flow[21]

Both Fmax and FRM are described in Section 3.1 in further detail. The Fref is the flow on a network element prior to day-ahead cross-zonal commercial transactions (including nominated long-term exchanges).

Finally, the flow-based domain is defined by the described parameters, representing all feasible combinations of commercial exchanges between participating bidding zones. Hence, in contrast to the NTC-based approach, commercial exchanges between two bidding zones are dependent on feasible commercial exchanges between other bidding zones. The crucial role of the appropriate determination of input parameters is explained in further detail in the appendix.

The main advantage of FB MC is a better representation of the physical characteristics of the transmission grid. This enables a less conservative consideration of capacities, i.e. flow-based parameters, leading in most cases to a larger flow-based domain and higher welfare gains than under the NTC-based approach.

ARTIFICIAL INCREASE OF THE FLOW-BASED DOMAIN

Since 26 April 2018, a mandatory minimum RAM of 20% on all critical network elements in CWE has been applied (so-called minRAM), without any further grid security considerations.[22] As part of the European legislative electricity market framework released in 2019[23], the Regulation (EU) 2019/943 on the internal market for electricity provides for an increase of this minimum trading capability to 70% starting from 1 January 2020. However, several TSOs have been granted a timely restricted derogtion from this rule. If structural congestions in a bidding zone prevent the provision of a 70% margin in 2020, member states are entitled to publish a so-called action plan explaining the reasons and future measures that will ensure a stepwise implementation of the 70% minRAM until 1 January 2026. Amongst other member states, Germany has opted for such an exemption clause[24].

[21] Prior to minRAM adjustment

[22] Via an artificial increase of the flow-based domain

[23] The 'Clean Energy for All Europeans Package' entered into force on 4 July 2019

[24] An overview on the 'Clean Energy Package' and its relevance for the future market and grid situation is provided in Section 6.1

ENHANCEMENT OF DAY-AHEAD MARKETS AND FLOW-BASED MARKET COUPLING

In order to achieve the target model of a single European electricity market, local markets have been gradually integrated and coupled at a regional level as from 2006 with the first market coupling of the Belgian, Dutch and French day-ahead markets.

The latest major step towards the target model was the introduction of FB MC in CWE back in 2015. Currently, TSOs are already working on the introduction of FB MC in the capacity calculation region (CCR) Core, which encompasses Eastern Europe in addition to Central and Western Europe. TSOs of the Core CCR have to implement FB MC no later than 1 December 2020, as stipulated in the ACER Core Capacity Calculation Methodology (CCM) decision (Art. 28)[25].

2.3 INTRADAY MARKET

European-wide intraday coupling is an additional key component for achieving the single European energy market. With the rising share of fluctuating generation, connecting intraday markets through cross-zonal trading is an increasingly important tool for market participants to keep positions balanced.

The Single Intraday Coupling (SIDC) of local intraday markets is realised in the Cross-Border Intraday (XBID) project. Its purpose is an increase in the overall efficiency of intraday trading. The second wave go-live of the XBID project in November 2019 has been an important step towards the overall European market integration, adding seven additional countries. XBID is now bringing together 21 countries[26]. The project partners consist of the European-nominated electricity market operators (NEMOs), EPEX SPOT, GME, NordPool and OMIE as well as the North-Western European and Baltic TSOs. In October 2019 the highest number of trades in SIDC history so far – 2.3 million with nearly 100,000 trades in one single day (21 October) – has been reached.

[25] See ACER Decision 02-2019 on the Core CCR TSOs' proposals for the regional design of the day-ahead and intraday common capacity calculation methodologies

[26] First 14 countries: Sweden, Norway, Finland, Estonia, Latvia, Lithuania, Portugal, Spain, France, the Netherlands, Belgium, Germany, Austria and Denmark; seven additional countries: Bulgaria, Croatia, Czech Republic, Hungary, Poland, Romania and Slovenia

3. MARKET ANALYSIS 2019

GERMANY BECOMING A NET IMPORTER DURING SUMMER 2019.

3.1 CAPACITY CALCULATION

As the main feature of the FB MC is better consideration of transmission constraints in the market, the determination of the available capacities between bidding zones requires a translation of physical transmission constraints into (simplified) commercial transaction constraints.

HIGHER MAXIMUM ALLOWABLE POWER FLOWS (FMAX)

The maximum allowable power flow on a critical network element (Fmax) is derived from the maximum current on a critical network element (Imax). Imax is the physical (thermal) limit of the critical network element, which depends on installed components (conductor, bundle, instrument transformer, etc.) and the weather conditions. In addition to the physical limits of the network element itself, other relevant limitations need to be acknowledged. Such limitations include, in particular, maximum allowable voltage inductions into parallel infrastructure, e.g. gas pipelines that must not exceed certain threshold values. Otherwise, safe and secure operation of the infrastructure ensuring human safety in particular would no longer be guaranteed.

20%

... increase of thermal limits due to the continued implementation of dynamic line rating by Amprion

The capacities made available for cross-zonal commercial exchanges are – amongst other parameters[27] – determined by the maximum allowable power flow on a critical network element, which is an input parameter for the flow-based capacity calculation process.

In order to support cross-zonal trade and as part of continuous improvements of the FB MC, CWE TSOs introduced seasonal and/or adaptive Fmax values. Amprion, like some other TSOs, implemented dynamic line rating leading to higher capacities, in particular during cold periods with higher electricity demand. Accordingly, import and export capabilities have been increased during the winter period in particular, with higher electricity demand and a corresponding higher socio-economic value.

[27] Further explanations can be found in Section 2.2.

After implementation of the process for coordinated remedial actions and the subsequent elimination of Final Adjustment Values (FAV)[28] on critical network elements, Amprion introduced adaptive Fmax values on further lines for the winter period 2016/17. In 2018 and 2019, CWE TSOs continued this development. Amprion, for example, introduced a dynamic line rating approach on its transmission lines, allowing adaptive Fmax values as a function of weather conditions, i.e. temperature. Through the aforementioned measures, thermal limits can be increased by more than 20%, in particular during cold weather conditions usually associated with a high electricity demand.

LOW FLOW RELIABILITY MARGINS (FRM) FOR AMPRION

In order to cope with uncertainty, i.e. deviations from forecasts, between the points in time of the capacity calculation and real-time operation, TSOs apply reliability margins for the critical network elements under consideration. The so-called Flow Reliability Margin (FRM) is deducted from the corresponding Fmax value and accordingly reduces the Remaining Available Margin (RAM) considered in the capacity calculation process. FRM values in the CWE region are usually between 5% and 23% of the respective Fmax value.

Amprion applies FRM values which are far below the average in CWE. With only 9% FRM on average (2015–2019), the low Amprion margins contribute to comparatively higher capacities that are made available to the market.

The FRM values on all active critical network elements in CWE range from 34 to 357 MW (i.e. FRM of 183 MW or 13% of Fmax on average) in the CWE region for 2015–2019.

Right from the beginning of the FB MC in 2015, Amprion applied FRM values much lower than the average of CWE. As shown in Figure 6, FRM values on active critical network elements of Amprion amount to only 158 MW or 9% of Fmax on average. Accordingly, the restriction of cross-zonal trade due to uncertainty is rather limited for critical network elements of Amprion.

Low Amprion margins contribute to comparatively high capacities that are made available to the market

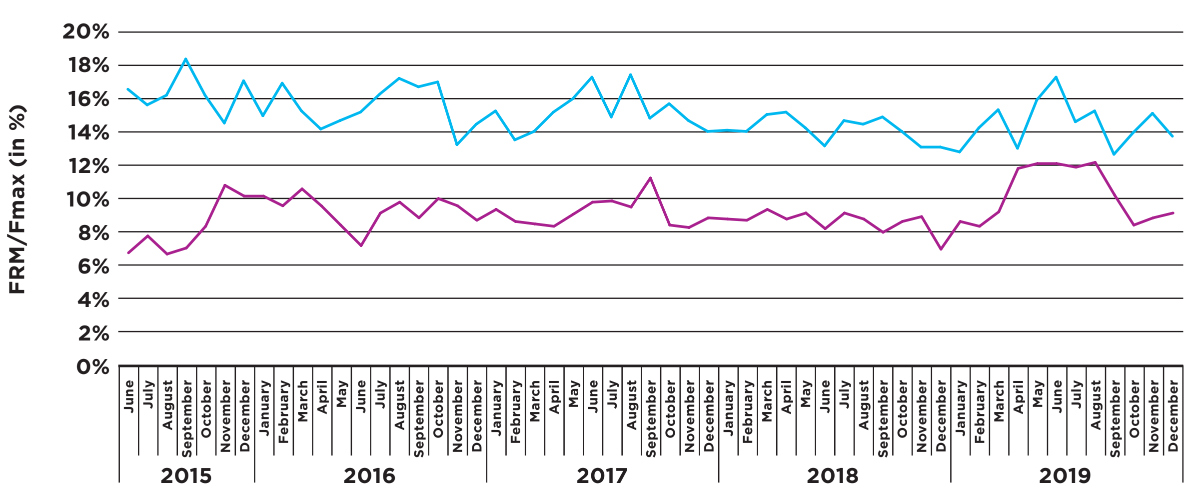


Figure 6: Monthly average FRM values of active constraints in CWE (2015–2019)

Amprion **Other TSOs**

9 % FRM

The restriction of cross-zonal trade due to uncertainty is rather limited for critical network elements of Amprion

The slight increase of FRMs observed for Amprion in 2019 (10% on average) can be explained by the further reduction of active critical branches in 2019. While the amount of Amprion's critical branches considered in the FB MC in 2016–2017 was higher, in 2019 it was mainly those branches active in the FB MC (i.e. limited the trades in CWE) which had a slightly higher FRM (e.g. the French-German interconnector Vigy/Ensdorf with 12%). Yet, in total FRM values still remain low on average.

According to a recalculation of FRM values in the course of a study performed by CWE TSOs in 2016, uncertainty and corresponding FRM values increased after the go-live of the CWE FB MC. However, in order to not limit cross-zonal trade, CWE TSOs decided not to increase FRM values, meaning that TSOs take the risk.

3.2 MARKET COUPLING AND CAPACITY ALLOCATION

The outputs of the flow-based capacity calculation process are submitted to the market coupling processes which are executed by NEMOs. Subsequently, the market coupling algorithm determines optimal market prices and net positions (importing or exporting), taking into account the flow-based constraints.

One of the main targets of this market coupling process is the reduction of market price differences in the market coupling region. In the event of sufficient cross-zonal transmission capacities, electricity generation and demand can be regionally balanced, leading to welfare gains.

BILATERAL DAY-AHEAD EXCHANGES IN CWE

Figure 7 shows the bilateral day-ahead exchanges from Germany to the CWE region (France and the Netherlands) resulting from day-ahead market coupling. Such day-ahead exchanges can also be referred to as day-ahead commercial exchanges since they result from the commercial day-ahead market coupling process[29]. The exchanges show some fundamental differences before and after the separation of the German/Luxembourgian and Austrian bidding zones (DE/LU-AT split) in 2018.

[28] FAV can be used by TSOs to reduce or increase the Remaining Available Margin (RAM) on a critical network element for very specific reasons, i.e. system security reasons.

[29] In overall terms, all commercial exchanges across all time frames (long-term, day-ahead, intraday and balancing) between bidding zones translate into physical flows between those bidding zones (physical flows that are shown in Section 4). They do not follow the same path, however. In other words, a commercial exchange from one bidding zone to another may physically flow through other bidding zones.

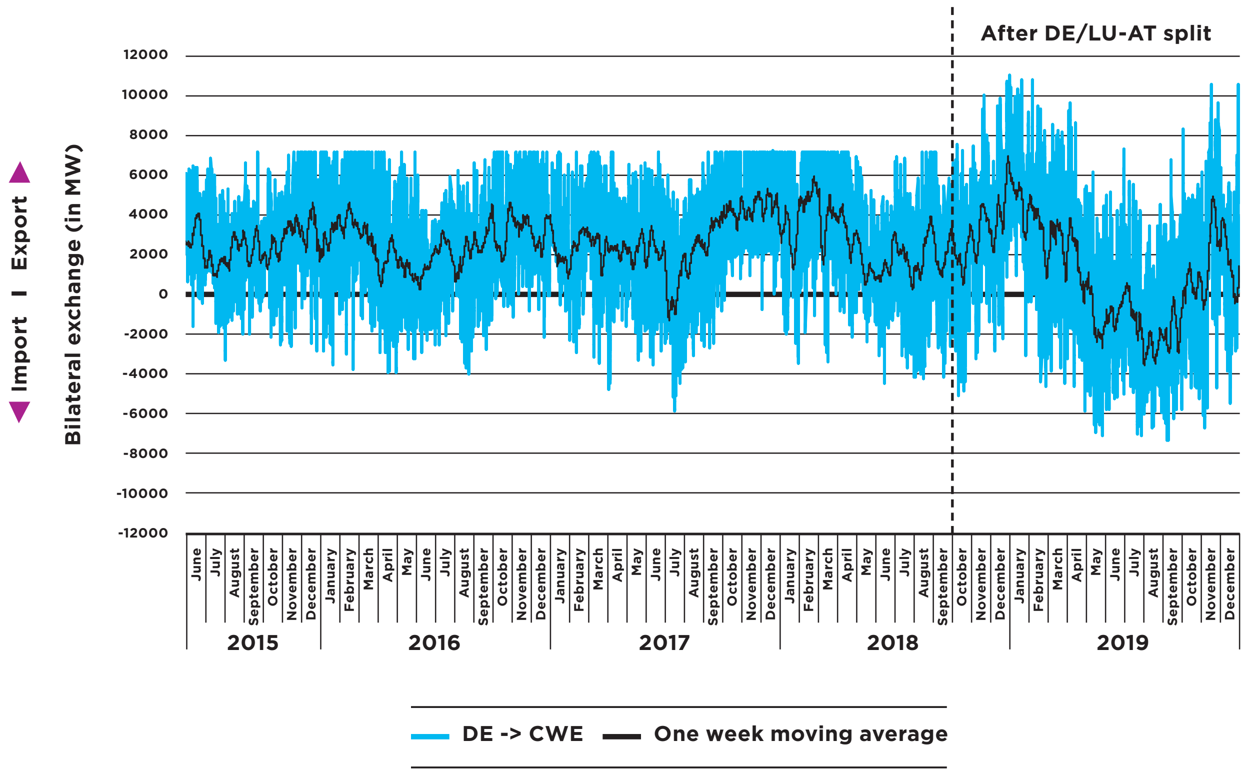


Figure 7: Day-ahead exchange from Germany to CWE region (i.e. DE to FR and NL)
(black line: moving weekly average) – for comparative reasons, please note that the exchange to Austria is not considered

17 TWh

… decrease of German exports to CWE region in 2019

Before the DE/LU-AT split in the years 2015 to 2018, the level of day-ahead exchanges from Germany to the CWE region followed a relatively constant seasonal pattern (see Figure 7) and the exchanges never exceeded a predefined level of 7,000 MW (German export constraint).

After the introduction of the DE/LU-AT split in October 2018 and in particular during the first few months of 2019, bilateral day-ahead exchanges from Germany to the CWE region increased beyond 7,000 MW and remained at those high levels for some time. The removal of the 7,000 MW German export constraint and the introduction of the new Austrian bidding zone were the main reasons for this increase.

However, in the summer months of 2019, German exports towards CWE declined substantially, turning into net imports during May, June and August. The main reason for the higher German imports during this time has been the high CO_2 price and the corresponding merit order shift. CO_2-intense lignite and coal-fired power plants in Germany have been replaced partly by foreign coal plants and partly by less CO_2-intense gas power plants. As will be explained in detail in Section 4, this considerable increase of imports by Germany resulted in a considerable decrease of redispatch costs.

While still being a net exporter in 2019 as a whole, German day-ahead exports to the CWE region (i.e. DE to FR and NL) decreased by 17 TWh.

BILATERAL DAY-AHEAD EXCHANGES IN CWE: FOCUS ON NEW BIDDING ZONE AUSTRIA

Figure 8 displays the development of the bilateral day-ahead exchanges from Germany to Austria including both the time frame before the DE/LU-AT split and after. When comparing both sides of Figure 8, one must consider that bilateral exchanges took place within one bidding zone and hence without restrictions before 1 October 2018. After 1 October 2018 (indicated by the dotted vertical line) the exchanges took place between two separated bidding zones.

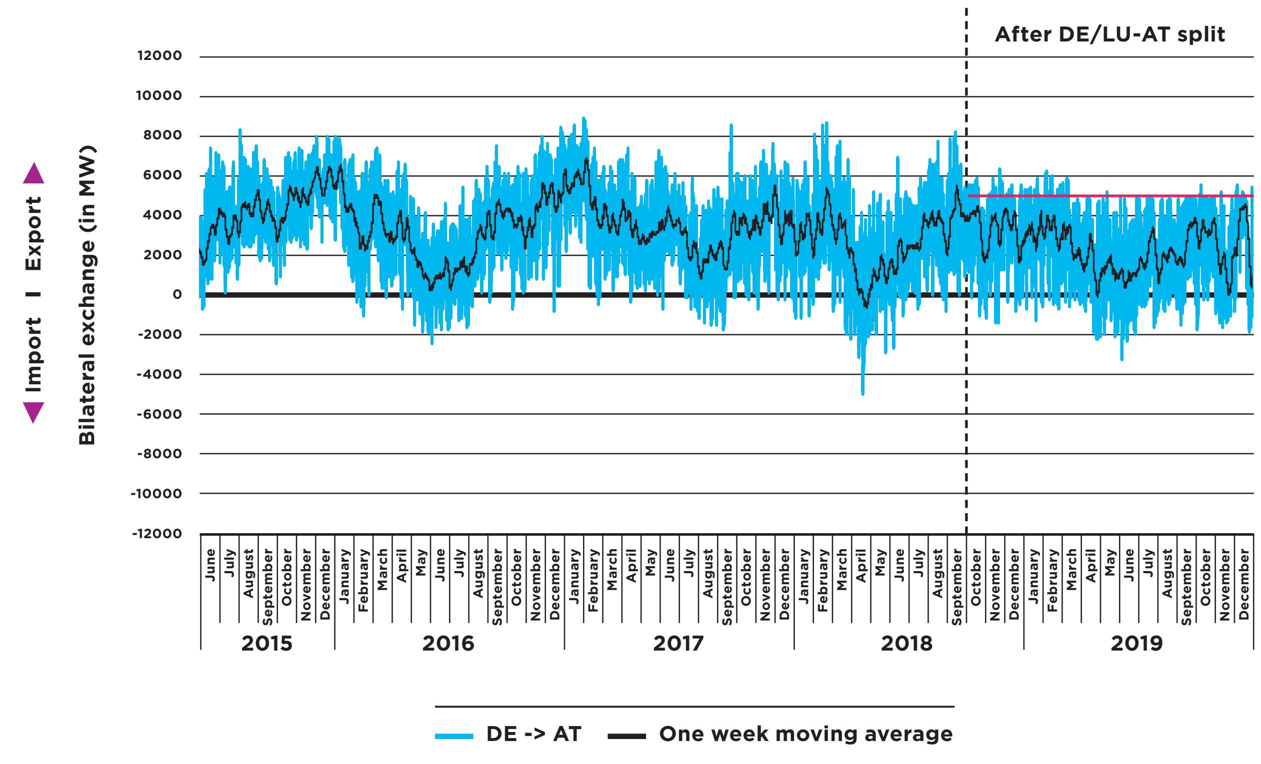


Figure 8: Day-ahead exchange from Germany to Austria
(black line: moving weekly average)

In general, the graph shows that Germany has been exporting to Austria steadily over the last few years. However, in some hours and in particular during the summer months with lower wind generation in Germany and higher availability of hydro generation in Austria, imports from Austria to Germany have been observed.

After the split, the level of export was still quite high. Yet, particularly visible in the second half of 2019, the export capability was limited as export levels did not reach again the historic values observed in the times before the split. This shows (in particular when analysing the physical flows in Section 4.1) the exchange-limiting impact of the bidding zone split. The red line in Figure 8 indicates the long-term transmission capacity at the German-Austrian border, which is currently 4,900 MW. Such long-term transmission rights at bidding zone borders have to be considered in the FB MC (via the so-called LTA inclusion). If the flow-based domain[30] turns out not to be sufficiently large to ensure the coverage of long-term transmission rights, it is artificially increased, causing additional redispatch needs.

[30] See explanation provided in Section 2.2.

DAY-AHEAD NET POSITIONS PER COUNTRY

In order to provide a full picture regarding the import and export situation of the CWE bidding zones, the following analysis considers all bidding zone borders (not only CWE, but also Switzerland).

In general, the net position of a bidding zone shows the total day-ahead imports and exports from and to all bidding zone borders. Therefore, a positive net position indicates a net exporting bidding zone, while a negative net position shows a net importing bidding zone.

While for Germany the day-ahead net positions have remained high over the past few years, in 2019 the lowest export surplus in six years was recorded. This development is also in line with the previous results of the bilateral exchange analysis focusing on CWE borders. For the first time, Germany became a net importer in the months May, June and August 2019 (cf. grey area in Figure 9).

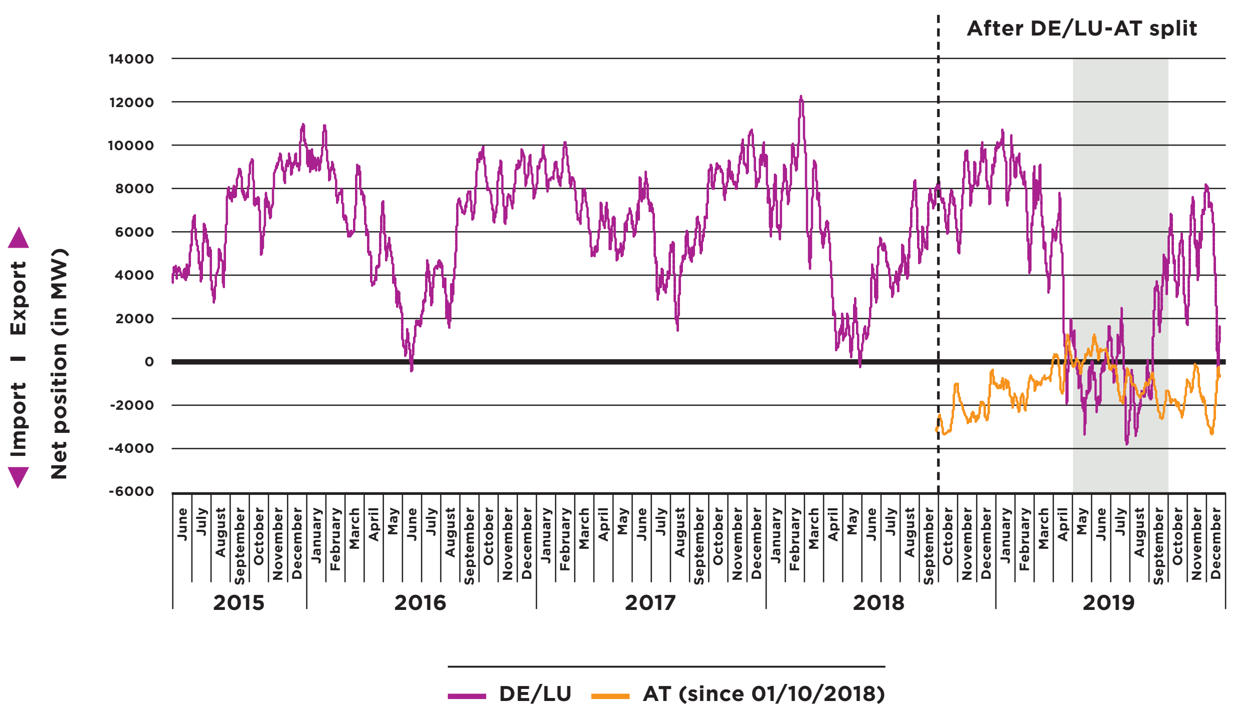


Figure 9: Comparison of day-ahead net positions for Germany/Luxembourg and Austria
(considering all country borders except DC interconnectors, moving weekly averages)
data source: Vulcanus

AMPRION MARKET REPORT 2020

As already outlined in Section 3.2 on bilateral day-ahead exchanges, the decrease in German exports in 2019 can be explained in particular by the observed increase in the CO_2 price (as well as quite stable gas prices) and the linked shift in the European merit order. As a consequence of the higher production costs, German coal-fired power plants, in particular, have been substituted by foreign generation.[31]

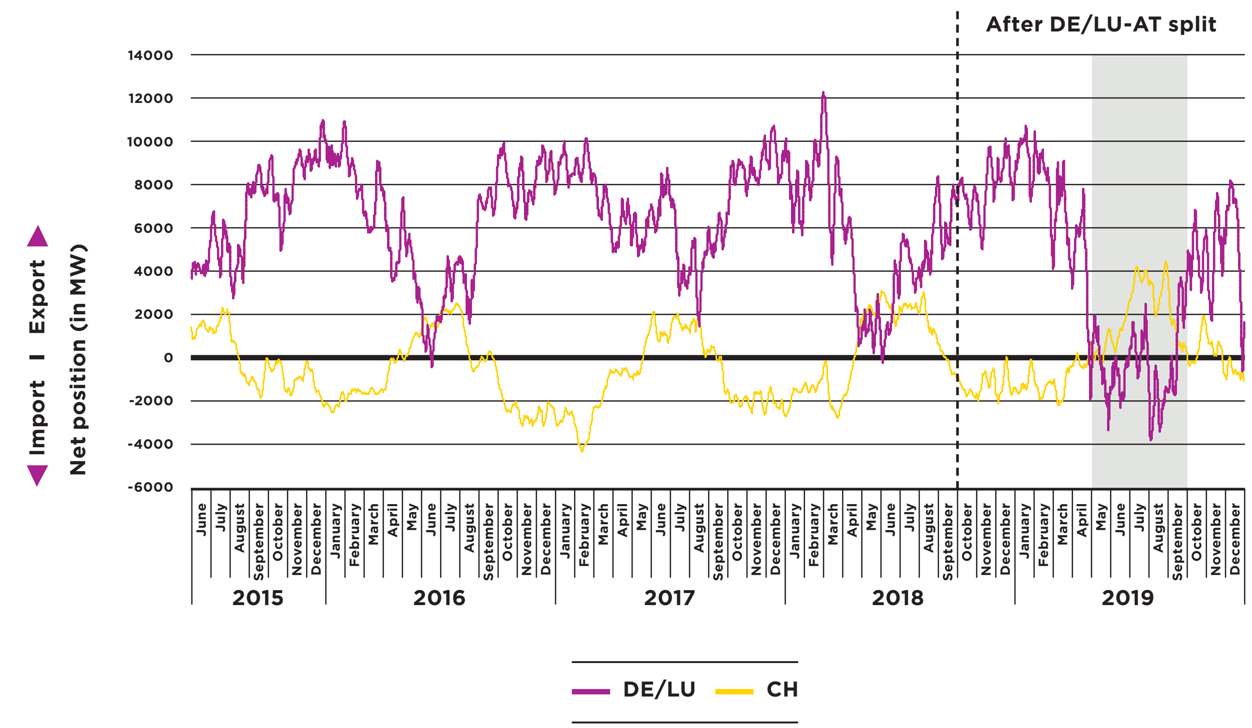


Figure 10: Comparison of day-ahead net positions for Germany/Luxembourg and Switzerland
(considering all country borders except DC interconnectors, moving weekly averages)
data source: Vulcanus

Thus, Germany imported from its neighbours. In particular France exported considerably more during the summer months. Also Switzerland increased its exports during the summer, while the imports from Belgium and Austria decreased during this time (see grey areas in Figure 9, Figure 10 and Figure 11).

[31] Please note the decrease in electricity production from German lignite and coal-fired power plants illustrated and quantified in Section 4.2.

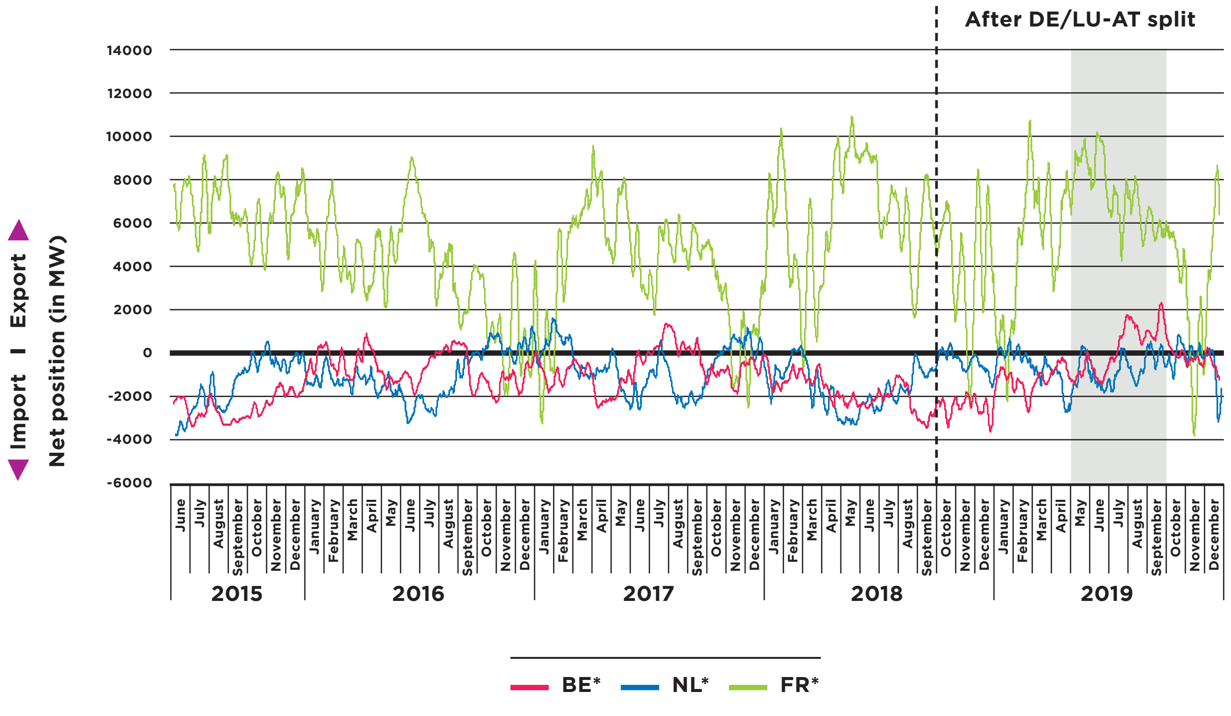


Figure 11: Comparison of day-ahead net positions for Belgium, the Netherlands and France
(considering all country borders except DC interconnectors, moving weekly averages)*
data source: Vulcanus

For Belgium, a typical importing country, the picture was different in 2019, when for the first time Belgium exported more than it imported.[32] This can be explained by a much higher availability of Belgian nuclear power plants compared to 2018 (reaching again the level of 2017)[33], a steady increase in renewable power (mainly offshore) generation (+17% compared to 2018) as well as the general development of interconnection in Europe.

INCREASING TREND OF PRICE CONVERGENCE IN CWE

The reduction of price differences within a region is one of the main targets of market coupling. Sufficient cross-zonal transmission capacities are a crucial prerequisite for achieving price convergence (i.e. price differences equals zero).

However, other fundamental factors significantly impact the market as well. On the one hand, considerable changes in the generation mix, i.e. decommissioning and unavailability of conventional generation units, have led to a shift of generation centres in CWE countries. On the other hand, import needs are strongly driven by power plant availabilities and the infeed from variable renewable energy sources as well as electrical demand, which in turn are heavily impacted by the natural variability of climate and weather conditions.

[32] *Please note that the net positions displayed in the figures do not consider exchanges from DC interconnectors. For Belgium, considering the missing NEMO cable would show Belgium as a net exporting country in 2019.*
[33] *In 2019, 49% of the power generated in Belgium came from nuclear plants, while in 2018 nuclear plants generated only 31%.*

Although CWE countries face an increasingly stressed supply situation, a steady increase of hours with full price convergence is observed. This provides evidence for the significant contribution of CWE TSOs to a cost-efficient balancing of supply and demand across the CWE region.

In the case of sufficient cross-zonal exchange capacities, no price differences between CWE bidding zones occur. If commercial exchanges are limited by active transmission constraints, prices between CWE bidding zones diverge. Accordingly, price convergence is an indicator for the level of market integration in the CWE region.

Figure 12 shows the further increasing level of market integration in 2019.

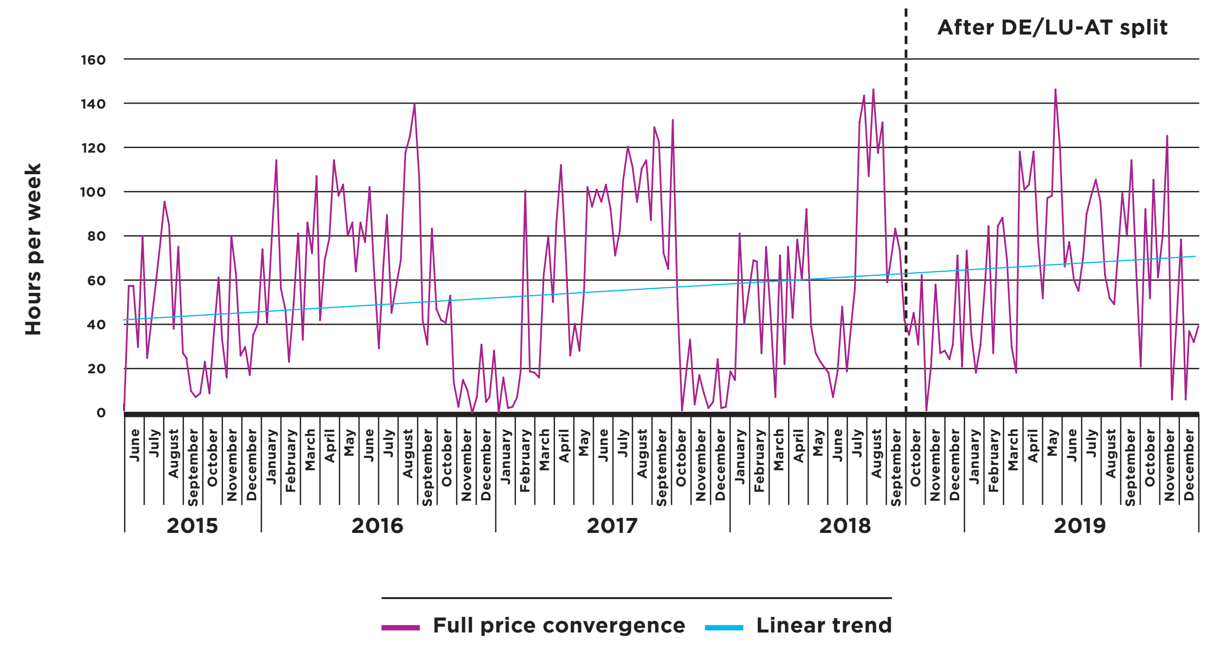


Figure 12: Development of hours per week with unlimited CWE trading 2015–2019, i.e. hours per week with full price convergence
(price spreads between CWE bidding zones equals 0)[34]
data source: ENTSO-E transparency platform

[34] *Please note that starting from 1 October 2018 the price convergence in CWE also considers the bidding zone AT.*

In total, an overall increasing trend for price convergence in CWE is observed (cf. Figure 12). While the price convergence in CWE reached 32% in 2018, a further increase to 42% has been observed in 2019. With 55%, the highest bilateral price convergence for Germany has been observed with Austria, followed by 40% with the Netherlands, 36% with France and 34% with Belgium in 2019.

Figure 12 also shows that price convergence follows a seasonal pattern. In particular, during winter periods, price convergence in CWE decreased regularly over the past few years. Besides the infeed of renewables, the availability of base load power plants (in particular nuclear plants) and load peaks also impact the prices in CWE. The lower level of price convergence during the winter periods 2016/17 and 2017/18 has been mainly driven by the stressed supply situation in the CWE bidding zones in those years.

42 % *... increase in hours with full price convergence in CWE in 2019*

In 2018, the commissioning of the new Niederrhein/Doetinchem interconnector between Germany (Amprion) and the Netherlands positively impacted the price convergence (due to the additional exchange possibility).

By the further development of dynamic line rating in 2019, Amprion could increase the maximum transmission capacity of the internal Emsland transmission lines by 25%. These transmission lines are located in the North of Amprion's control area and connect offshore wind farms to the European transmission grid. An increase in the transmission capacity of these crucial lines leads to less congestion and therefore allows for higher trades in CWE. See also Sections 3.2 and 4.2 for further information on the Emsland transmission lines.

The introduction of the DE/LU-AT bidding zone border initially had a decreasing impact on the overall price convergence in CWE. In the last three months of 2018, a reduction was especially visible. However, the overall impact of the introduction of the DE/LU-AT bidding zone border on the price convergence in CWE is not straightforward. While the new bidding zone border facilitates competition between all CWE bidding zones for cross-zonal relevant transmission capacities located within Germany, it also limits de facto the exchanges between Germany and Austria.

Due to the high complexity of electricity markets, it is difficult to quantify the impact of the individual factors as they cannot be analysed on a stand-alone basis. Instead, they have to be considered in the complex environment of changes, not only in the transmission capacity between bidding zones, but also with regards to changes in CO_2 and fuel prices as well as RES infeed, plant availabilities, electricity demand and weather conditions.

Although the variance of the hourly day-ahead prices is quite high[35], Table 1 aims to give a first impression of the absolute average price levels in CWE.

[35] Prices follow seasonal patterns and might vary widely over the year.

Table 1: Day-ahead average price levels in CWE (in €/MWh), data source: ENTSO-E transparency platform

€/MWh	2015	2016	2017	2018	Until 09/2018	From 10/2018	2019
DE/LU-AT	31.82	28.99	34.19	-	41.73	-	-
DE/LU	-	-	-	-		52.59	37.67
AT	-	-	-	-	-	59.92	40.06
NL	40.06	32.24	39.31	52.53	-	-	41.19
BE	44.72	36.58	44.58	55.27	-	-	39.35
FR	38.45	36.70	44.97	50.20	-	-	39.45

While absolute average prices reached their maximum in 2018, they sharply declined in 2019. More precisely, the German average day-ahead price of 37.67 €/MWh for 2019 is significantly lower than the average price in 2018.

The high unavailability of Belgian nuclear power plants in the second half of 2018 has been the main driver for the significantly higher price level in CWE in 2018. As a result of the 50% lower generation from nuclear power plants, electricity production from gas-fired power plants in 2018 increased, combined with a large increase in imports (mainly from France). In 2019, the Belgian nuclear power plants again reached their usual availability level.

While the average day-ahead price in Austria exceeded the German price after the bidding zone split in 2018, the Austrian average price level dropped in 2019. However, it was still higher than the German average price level.

As for the other CWE bidding zones, the average price levels of the Netherlands and France also dropped in 2019 below the level observed in 2018.

INCREASE OF TRADING POSSIBILITIES IN CWE BY DECREASING SHARE OF ACTIVE CONSTRAINTS

CBCOs (so-called critical branch critical outage combinations) are necessary input parameters of the flow-based capacity calculation. However, depending on the likely market direction, only some of these CBCOs will act as limiting elements in the flow-based domain and therefore limit the exchanges in the CWE region. Such limiting elements are called active (in the sense of limiting) constraints.

The frequency of active constraints is subject to seasonal effects and driven by generation and load patterns in CWE countries. Improvements such as the introduction of adaptive Fmax values within the dynamic line rating concept on Amprion critical branches have reduced the frequency of Amprion's active CBCOs significantly over the last three years, further enhancing market integration in CWE.

The development of active constraints (Critical Branches, CBs) is subject to dynamic changes. While active cross-zonal elements are shown in Figure 13 as a cross-hatched area, internal active constraints of Amprion (DE), TransnetBW (DE), TenneT D (DE), TenneT NL (NL), Elia (BE), RTE (FR) and APG (AT) are shown as coloured areas. Please note that Figure 13 displays the frequency of all active constraints in the CWE region from May 2015 until December 2019. In other words, it shows how often a network element limited the CWE trades during one month. The cross-hatched area summarises all active cross-zonal constraints for the CWE borders (i.e. DE-NL, DE-FR, BE-NL, BE-FR and DE-AT).

AMPRION WILL CONTINUE ITS STRONG COMMITMENT OF RECENT YEARS

Amprion enables more trading in CWE by lowering the share of its own constraining network elements

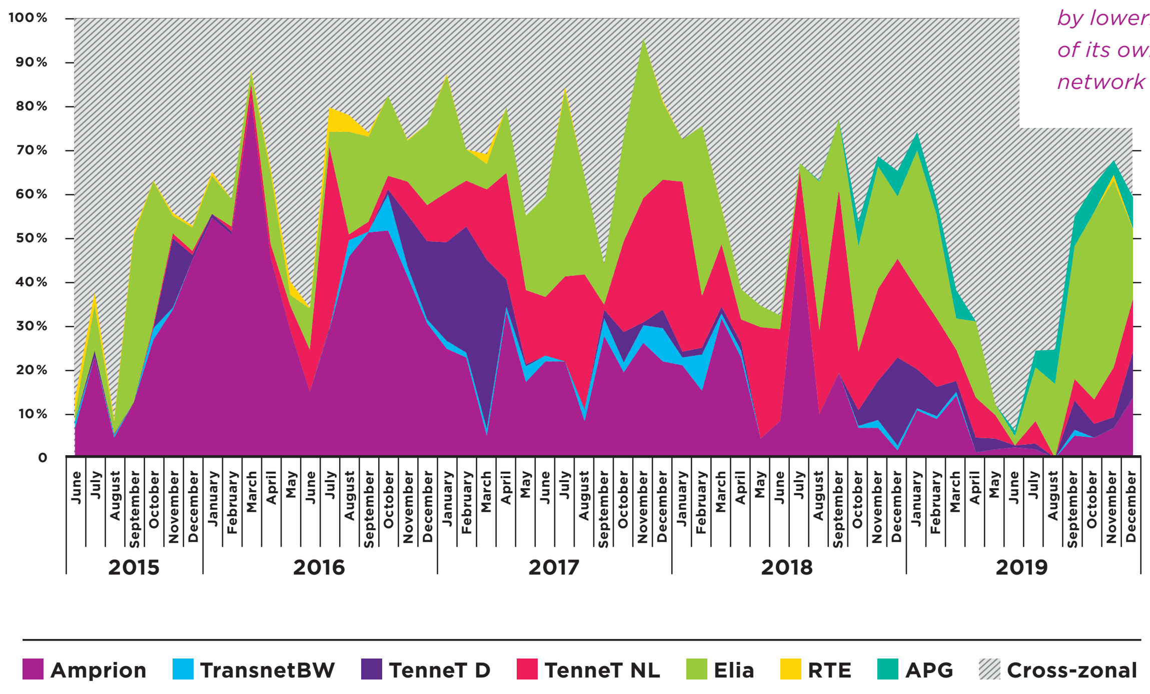
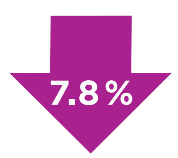


Figure 13: Decreasing share of Amprion's market-constraining internal network elements, i.e. relative frequency of active critical branches
(cross-hatched area = cross-zonal elements)[36]

While in 2016 and 2017 mainly internal CBs limited cross-zonal trades (see coloured areas), from mid-2018 onwards a shift towards cross-zonal elements can be observed (see cross-hatched areas).

This development is particularly visible for Amprion. Over the last three years, Amprion has significantly reduced its number of internal active CBs (fuchsia area). In 2019, only 7.8% of all active constraints were caused by Amprion internal elements, thus significantly contributing to the market integration progress in CWE.



... of all active constraints in CWE were caused by Amprion internal elements, enabling more trading in CWE

[36] *In order to show the frequency of active CBs over time, the percentages per month have been calculated applying a scaling to 100% for all months. Accordingly, the number of active constraints in one month (labelled as 100%) does not necessarily correspond to the number of active constraints of another month (also labelled as 100%).*

In this context, Figure 14 (below) shows to which extent the cross-zonal or internal network elements constrained the CWE trade in 2019.

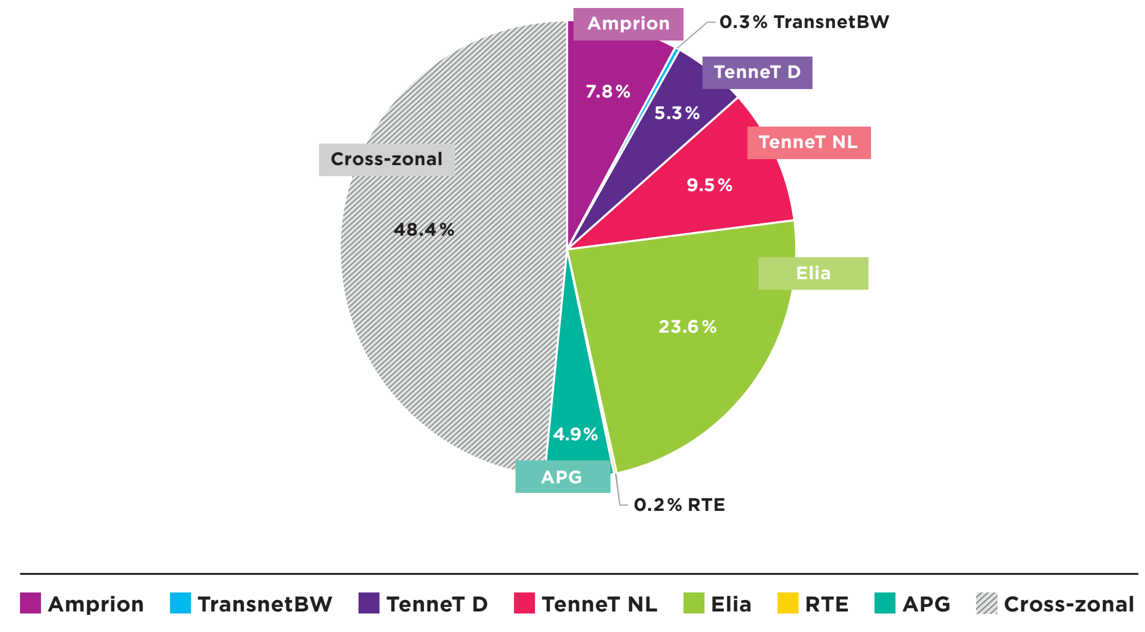


Figure 14: Share of active constraints in the CWE domain per TSO control area and cross-zonal elements in 2019[37]

In 2019, the distribution between cross-zonal and internal network elements limiting the CWE domain was fairly equal. While cross-zonal constraints limited the CWE trades to 48.4%, internal network elements counted for 51.6%, from which Amprion was able to reduce its share significantly during the last year to 7.8% in 2019.

This development is also in line with the previously shown increased price convergence in 2019 as fewer constraining elements generally lead to a more efficient market integration. At the same time, the frequency of the constraining cross-zonal elements increased significantly to almost 50% of all active constraints in 2019. This development can be seen as an advantage as fewer internal elements constrained the cross-zonal trade.

The geographical position of the limiting Amprion elements in 2019 is shown in the following Figure 15. Please note that the general information about the critical branches can also be downloaded via the utility tool available under JAO[38], but are presented transparently for the Amprion control area.

[37] *Please note that allocation constraints are not considered.*
[38] *See https://utilitytool.jao.eu/*

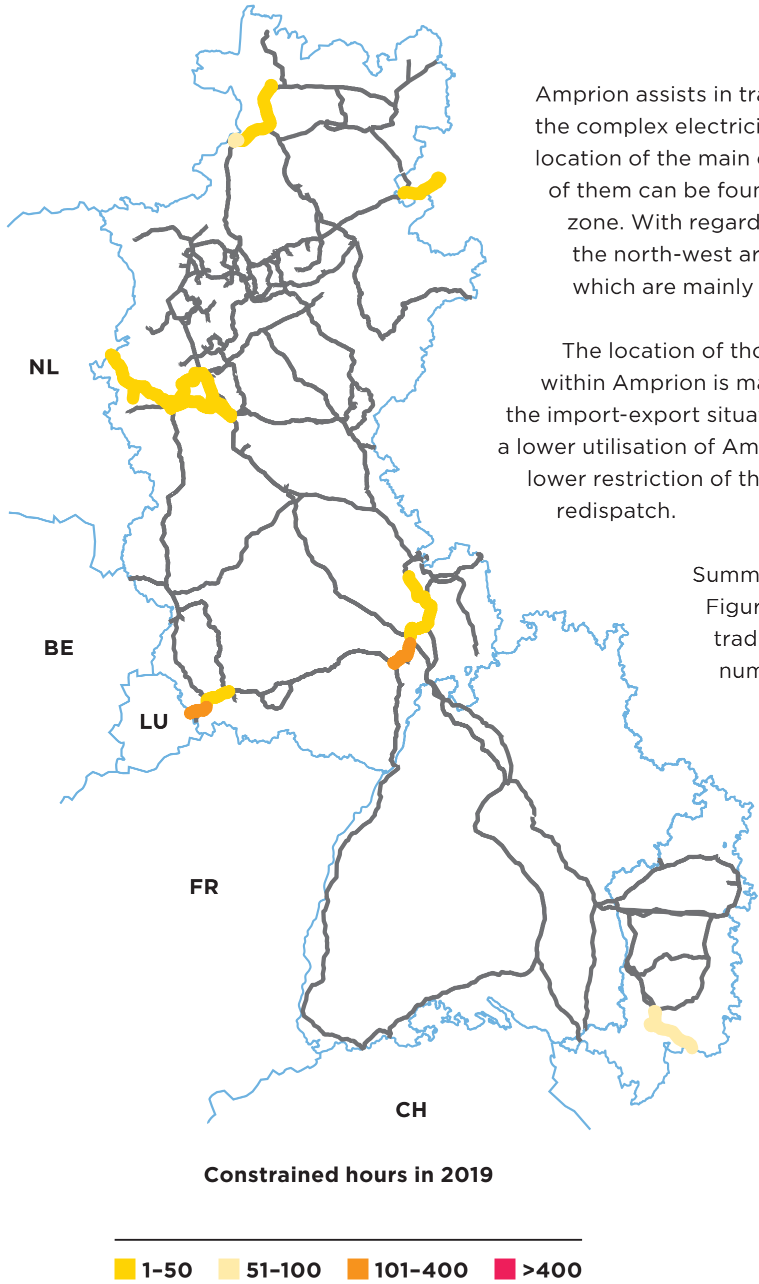


Figure 15: Location of major active critical branches in Flow-Based Market Coupling of Amprion in 2019

Amprion assists in transparency and enables the understanding of the complex electricity markets. For this reason, Figure 15 shows the location of the main constraining elements of Amprion in 2019. One of them can be found at the south-west border to the French control zone. With regard to internal elements, a particular focus lies on the north-west area and the so-called Emsland transmission lines, which are mainly influenced by North German wind generation.

The location of those limiting constraints indicates that congestion within Amprion is mainly caused by on- and offshore wind as well as the import-export situation. As observed in 2019, lower exports lead to a lower utilisation of Amprion's transmission grid and therefore also to a lower restriction of the CWE trades, as well as a reduction in necessary redispatch.

Summarising the results of the market analysis, Figure 16 illustrates the positive trend of increased trading possibilities in CWE. Figure 16 shows the number of hours during which the CWE market has been constrained by TSOs' networks. The amount of such constraints to market exchanges in CWE decreased significantly in 2019 by 39%, enabling higher electricity exchanges across borders.

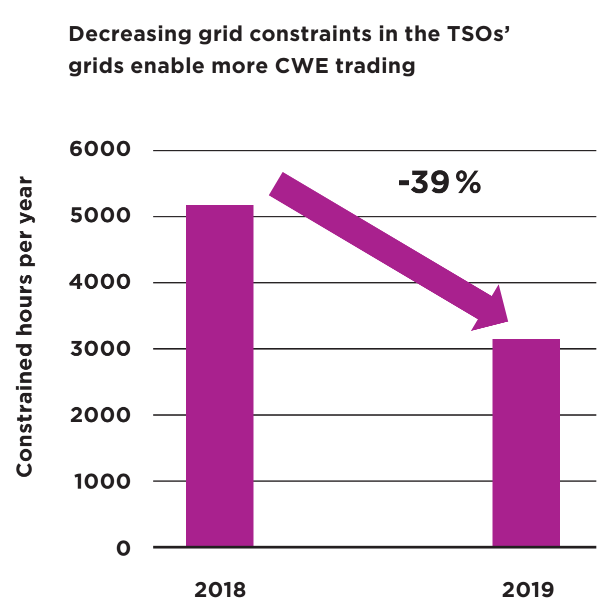


Figure 16: Development of hours per year with limited CWE trading 2018–2019

EXCURSUS: INTUITIVE PATCH DECREASES SOCIAL WELFARE OF FLOW-BASED MARKET COUPLING

So far, our market analysis for 2019 has shown that the amount of trade-limiting constraints decreased while the number of hours during which day-ahead prices in CWE converged increased. This development is expected, considering that in the case of sufficient cross-zonal exchange capacities, no price differences between CWE bidding zones occur. If commercial exchanges are limited by active transmission constraints, prices between CWE bidding zones diverge.

Yet, when FB MC has been introduced in CWE, it has been decided to limit the amount of possible FB MC outcomes to the so-called 'intuitive' FB[39]. The reason behind this decision[40] was to enhance public acceptance of this new, but complicated, market coupling algorithm. Yet, the label 'intuitive' is somehow misleading, as it does not refer to a mathematically correct market coupling solution, but to a market coupling solution that is 'more easily or more intuitively understood'. The so-called 'intuitive patch' forbids all market coupling solutions that are not intuitive. In a nutshell, a market coupling result (although mathematically correct) is considered as non-intuitive when the bilateral exchange is in the opposite direction of the price spread, for example a bidding zone with low price is importing from a bidding zone with higher price.

An illustrative example for intuitiveness is provided in the Appendix. The application of the intuitive patch is triggered by an FB MC result that includes bilateral exchanges that do not correspond to the bilateral prices difference between zones. In order to make the FB MC results more 'intuitive' (or in other words: to make them more comprehensible for market parties and stakeholders), an artificial constraint is added to the FB MC optimisation, changing exchanges and prices in such a way that they are no longer optimal, but more comprehensible for market parties and stakeholders. At the same time, the artificial constraint increases total system costs since exchanges are no longer optimal.

Whenever the 'intuitive patch' is activated, it changes the optimal market results (i.e. prices and exchanges), moving away from the mathematical optimum. While its activation has been quite limited in the past, this changed significantly in 2019.

As previously mentioned, day-ahead prices in CWE converged in 2019 in 42% of the year. Or in other words, prices in CWE diverged in the remaining time of the year. Hence, one would expect that transmission constraints occurred during these hours, which limited the CWE exchanges and consequently led to diverging prices. But this has not always been the case. In 2019, in around 20% of the year the activation of the 'intuitive patch' rather than transmission constraint has prevented the market prices from converging and consequently reduced social welfare[41].

Considering the order of magnitude observed in 2019, Amprion strongly doubts the continued application of the so-called 'intuitive patch', leading to a change of market results and higher costs for society.

[39] See https://www.jao.eu/support/resourcecenter/overview?parameters=%7B%22IsCWEFBMCRelevantDocumentation%22%3A%22True%22%7D

[40] During the so-called parallel run of the CWE FB MC, power exchanges and TSOs computed two FB market coupling simulations, one called 'plain' and the other 'intuitive'. In light of the results of the parallel run, it has been decided to choose the so-called FB intuitive results only.

[41] The number of hours during which the activation of the intuitive patch rather than transmission constraints prevented the market prices from converging more than doubled in 2019 compared to 2018.

AMPRION MARKET REPORT 2020

4. GRID OPERATION ANALYSIS 2019

REDISPATCH STRONGLY DEPENDS ON RES INFEED AND IMPORTS/EXPORTS.

4.1 PHYSICAL EXCHANGES IN CWE

The market coupling results are submitted to the TSOs and subsequently translated into physical flows during real-time grid operation.

Like the commercial exchanges, the physical exchanges from Germany to CWE remained at a high level even after the split of the German-Austrian bidding zone (despite the summer period in 2019). German exports declined significantly during the summer months and even turned into net imports. This is also visible in Figure 17, which shows the physical exchanges.

Like commercial exchanges, German physical flows also turned into imports during the summer months of 2019

While in 2015–2018 a continuous trend of high transits from north to south was observed, this trend decreased significantly during the summer months (grey area), and even led to a change of direction in June and August.

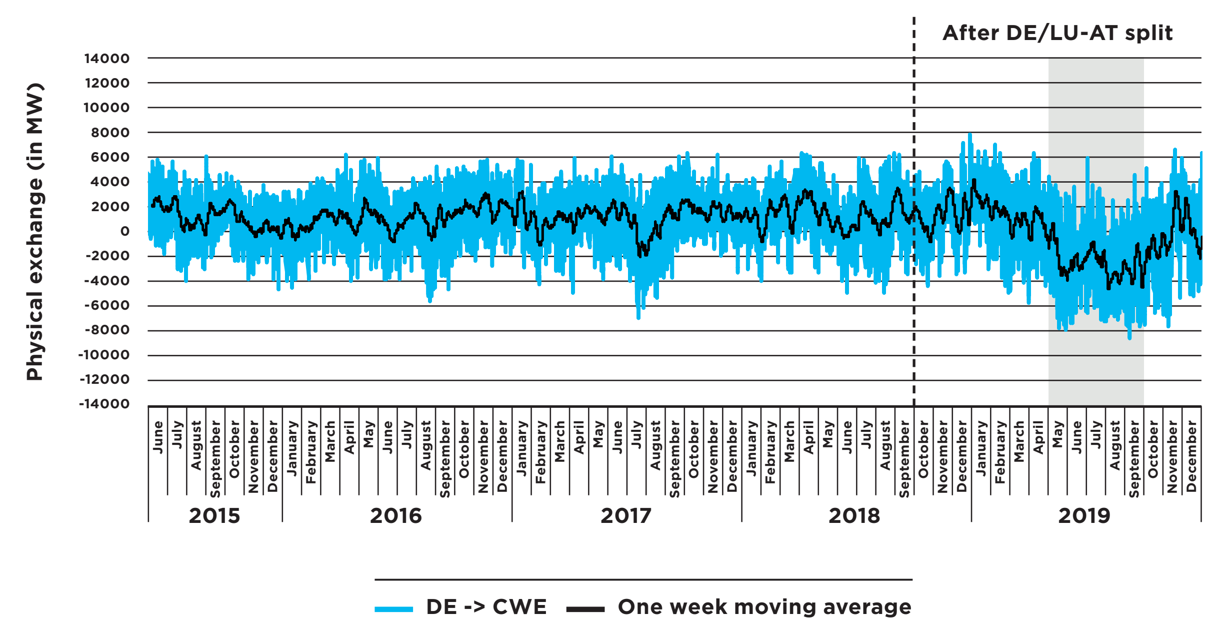


Figure 17: Physical exchange from Germany to CWE (i.e. DE to FR and NL), (black line: moving weekly average). *For comparative reasons, please note that the exchange to Austria is not considered.*

4.2 REDISPATCH

In order to avoid overloading of grid elements and critical voltage situations, TSOs apply remedial actions, i.e. topological and redispatching measures, in order to maintain a secure grid operation.

REDISPATCH VOLUME AND COSTS FOR GERMANY

During recent years, all German TSOs have generally faced high redispatch needs, in particular during winter periods when north-south transit occurs.

The number of redispatch measures per day indicates the occurrences of critical grid situations, where TSOs had to intervene in real-time operation. The average number of redispatch measures per day in Germany for 2019 was 15. The maximum in 2019 was 64 redispatch measures per day. Redispatch measures reached a historic maximum with 96 redispatch measures per day in winter 2016/2017.

Two main driving forces of German redispatch are wind infeed and the load and supply situation in southern CWE countries due to their corresponding import flows.

Exceptional decrease of redispatch volumes in 2019 observed

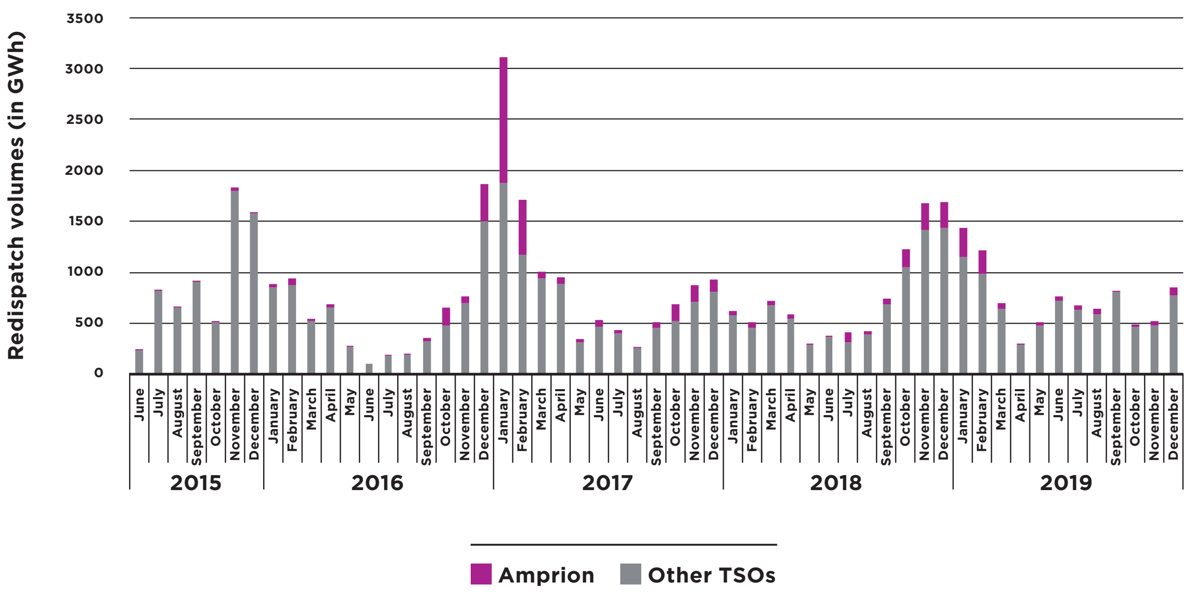


Figure 18: Total monthly redispatch volumes for Germany (including RES curtailment)
data source: www.netztransparenz.de

Figure 18 illustrates the monthly redispatch volumes for Germany. They decreased for all German TSOs in 2019 (compared to 2018).

REDISPATCH VOLUME AND COSTS: FOCUS ON AMPRION

While overall redispatch volumes for Germany decreased by around 6%, the particular decrease in Amprion's redispatch volumes amounts to approx. 17%. The decrease in Amprion's redispatch costs was even stronger at 38%. In times of increasing integration of RES, this development seems to be counter-intuitive at first glance. Yet, there are particular reasons for this development which are mainly related to the load and supply situation in Europe and some specific cases of reduced RES generation.

... reduction in Amprion's redispatch volumes due to exceptional events in 2019 (i.e. lower wind infeed and changed merit order)

In more concrete terms, the exceptional drop in redispatch volumes and costs of Amprion in 2019 can be explained by:

- A considerable reduction of RES curtailment necessary for alleviating congestion on the crucial Emsland transmission lines, due to non-availabilities of offshore converter systems and the implementation of dynamic line rating on the Emsland transmission lines.
- A reduction in north-south congestion in Germany due to the introduction of the German/Luxembourgian-Austrian bidding zone split in October 2018.
- A significantly changed load flow situation within Amprion's control area caused by a higher CO_2 price and the linked shift in the merit order. As a consequence of the higher production costs, in particular German coal-fired power plants have been substituted by foreign generation.
- Furthermore, in 2019, Belgium was a net exporter for the first time. The Belgium TSO Elia explains this as a much higher availability of Belgian nuclear power plants, a higher Belgian offshore wind infeed as well as the general development of interconnection in Europe[42].

For Amprion, congestions on the Emsland transmission lines are a significant driving force for inevitable curtailment of RES infeed. These transmission lines interconnect a major offshore connection point with Amprion's transmission grid. Congestion on these lines is related to situations of high offshore wind generation in combination with transits to Southern Germany or Europe in particular. In 2019, the high non-availability of offshore converter stations[43] for a period of a few weeks, led to a much lower offshore wind infeed and therefore lower utilisation of these particular lines. As a result, the need for RES curtailment decreased considerably. This situation can be considered as an extraordinary effect which is not expected to occur on a regular basis in future years.

The average CO_2 price increased significantly in 2019 by 57% to 24.80 EUR/t CO_2 (2018: 15.79 EUR/t CO_2). As CO_2 costs constitute a considerable part of the production costs of CO_2-intense lignite and coal-fired power plants, such a significant increase leads to changes in the European merit order. Lignite is replaced by less expensive and less CO_2-intense technologies, old coal-fired power plants in Germany are partly replaced by foreign coal-fired power plants with higher efficiencies (less efficient power plants are more affected by an increase in CO_2 costs than plants with a higher efficiency) and coal-fired power plants are replaced by less CO_2-intense gas-fired power plants (i.e. decreased coal-gas spread). Figure 19 underlines this by showing the development of electricity production by fuel type in Germany from 2018 to 2019.

[42] *See Elia press release 2020: https://www.elia.be/en/news/press-releases/2020/01/20200108_press-release_mix-electrique-2019*

[43] *A converter station links offshore wind parks to the main grid adapting also the wind park voltage to the voltage of the main transmission grid.*

Significant CO_2 price increase impacts German electricity production from lignite and coal

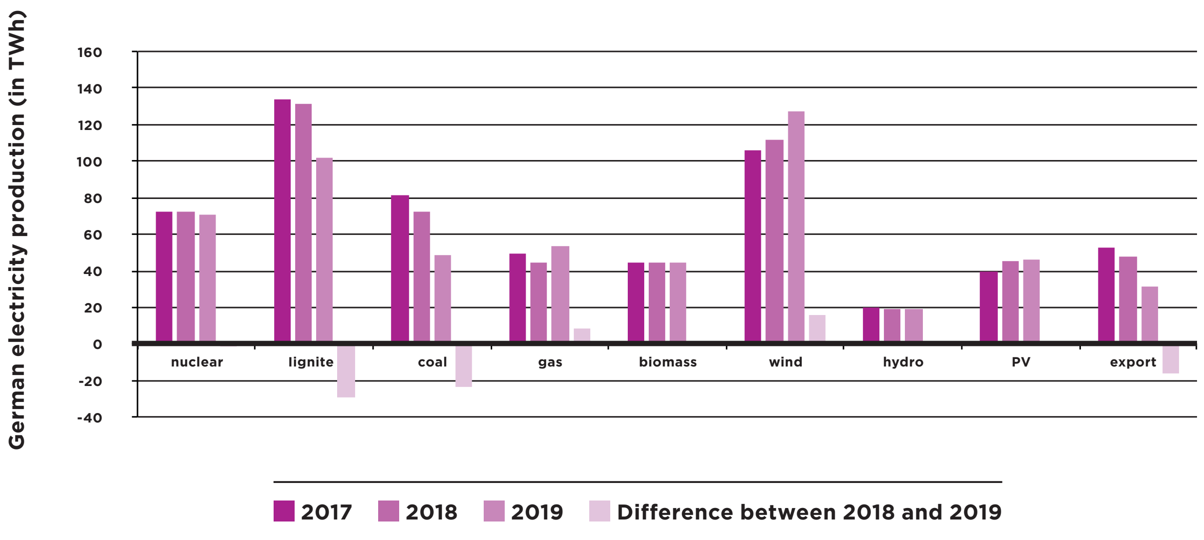


Figure 19: Development of German electricity production by fuel type (2017–2019)
data source: www.energy-charts.de

Electricity generation from lignite in Germany reduced by 29 TWh, and generation from hard coal reduced by 24 TWh. As explained in Section 3, this considerable reduction in German electricity generation from lignite and coal was also one driving force for the decrease in Germany's export. While still being a net exporter overall in 2019, total export decreased by 17 TWh. For three months, Germany even became a net importer, leading consequently to a lower level of congestion within Germany and therefore a decrease in corresponding redispatch costs.

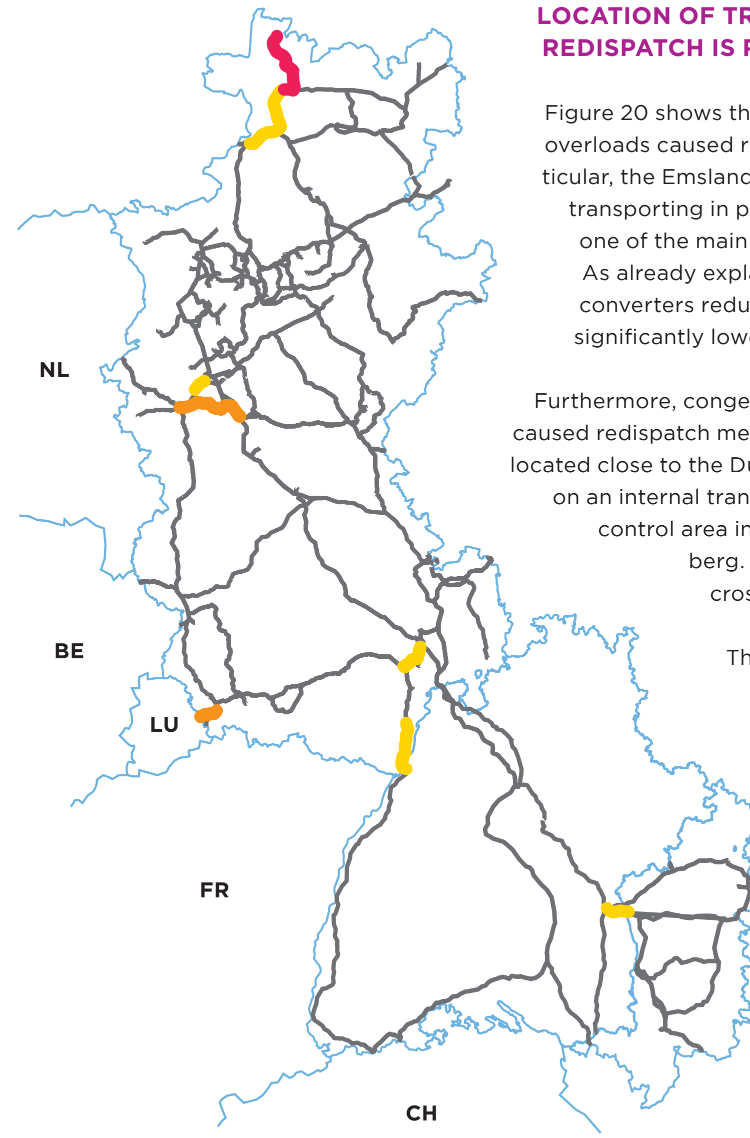
2019 was the first year in which Belgium became a net exporter and Germany became a net importer, at least during the summer months. The significantly changed import-export situation leads to changed load flows not only in Amprion's control area. However, an accurate matching of certain circumstances to particular decreases in Amprion's redispatch volumes cannot be quantified clearly due to interdependencies and overlaying effects in the highly interconnected European grid. In particular, simultaneous reduction in German export and redispatch volumes as well cannot be extrapolated to the future e.g. further shutdowns of power plants may lead to further decreases in export, but will most likely require additional redispatch.

LOCATION OF TRANSMISSION LINES OF AMPRION FOR WHICH REDISPATCH IS REQUIRED

Figure 20 shows those transmission lines in Amprion's control area where overloads caused redispatch measures and RES curtailment in 2019. In particular, the Emsland[44] transmission lines (located in the north of Germany), transporting in particular offshore wind from the North Sea, have been one of the main drivers of Amprion's redispatch measures in recent years. As already explained before, an unusually high unavailability of offshore converters reduced the 'pressure' on these lines in 2019 and therefore significantly lowered the necessary RES curtailment.

Furthermore, congestions on one of the German-French interconnectors caused redispatch measures in 2019 as well as one internal transmission line located close to the Dutch border. Further congestions have been observed on an internal transmission line located in the southern part of Amprion's control area in the surroundings of the federal state of Baden-Württemberg. Please note that this transmission line is sensitive to cross-zonal trade with France.

These lines were already identified in Section 3.2 when analysing the frequency of active constraints in the market. The reason why the Emsland transmission lines have not yet been identified in the FB MC is their low sensitivity to cross-zonal exchanges, which is rooted in their location further away from the country border. As their sensitivity to cross-zonal exchanges is rather low, consequently they do not limit market exchanges in CWE.

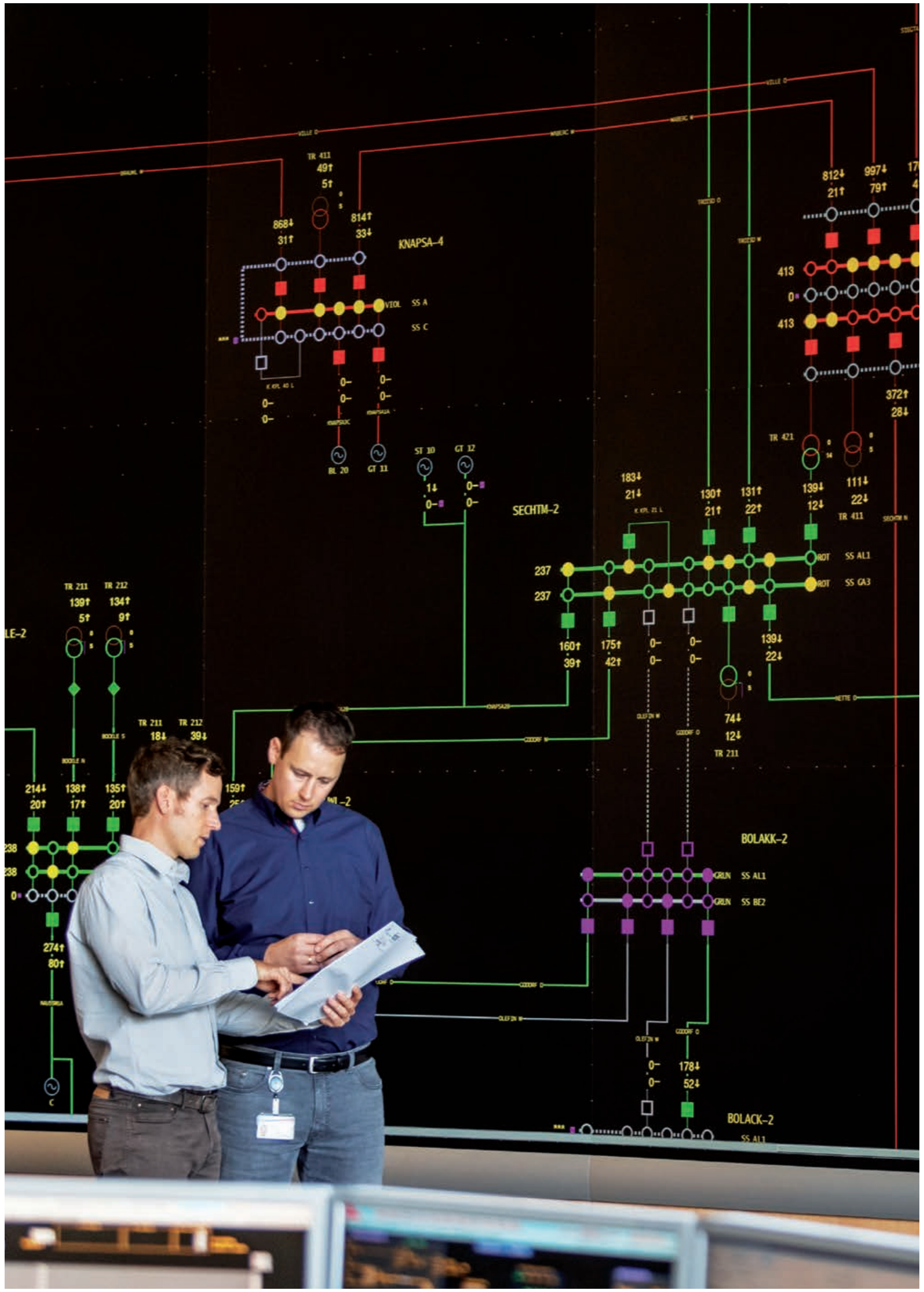


Redispatch volume in 2019

1.5–10 GWh | 10–30 GWh | 30–100 GWh | >100 GWh

Figure 20: Main transmission lines in Amprion's control area for which redispatch was required in 2019

[44] *Please note that the Emsland transmission line forms a connection between Amprion and Tennet DE.*



5. EXTRAORDINARY OCCURRENCES

SOME SPECIFIC CRITICAL MARKET AND GRID SITUATIONS COULD BE SUCCESSFULLY MANAGED BY TSOS AND OTHER INSTITUTIONS.

5.1 CWE DECOUPLING IN JUNE 2019

The decoupling in 2019 was the second since CWE market coupling began, the first one being in 2011.

Due to a technical issue in the CWE day-ahead Flow-Based Market Coupling processes for the business day 8 June 2019, the German bidding zone was decoupled from the overall European market. Hence, for every hour of this day, the day-ahead net position was zero and neither imports nor exports in the day-ahead FB MC could take place.

Even in this worst-case scenario, the day-ahead hourly prices for the German hub did not reach extremes. With hourly prices between -90 €/MWh and +27.30 €/MWh, prices reached unusual levels, but were not extreme. An explanation for this moderate impact on the decoupling is the high liquidity of the German/Luxembourgian bidding zone. Large and highly liquid bidding zones can also operate effectively on their own, which is an advantage in stress situations.

The decoupling in 2019 was the second since CWE market coupling began, the first one being in 2011. Power exchanges involved in the FB MC (so called NEMOs) and TSOs, in close cooperation with regulatory authorities and system providers, are continuously improving their systems in order to reduce the rare probability of such events. However, even with extensively tested redundant technical systems and backup processes, market incidents can still occur. Therefore, all market participants should always be prepared to use existing backup processes (so called 'explicit shadow auctions'). This would help to limit negative market impacts in the case of potential future decoupling events such as the one in 2019.

5.2 ENDANGERED GRID SECURITY: INVESTIGATION INTO SYSTEM IMBALANCES IN GERMANY IN JUNE 2019

Significant system imbalances occurred due to complex weather conditions and a low incentive for balancing responsibility parties to keep a balanced portfolio.

Significant system imbalances occurred in the German power system on four days in June 2019 (06/06/2019, 12/06/2019 and 25+26/06/2019). Resulting from a shortfall in generation relative to total system load, these imbalances reached a maximum of more than 6,000 MW (on 06/06/2019 and 25/06/2019) and nearly 10,000 MW (12/06/2019). Aside from these peak values, significant imbalances persisted for several hours on these days. In order to regain control of this situation of endangered security of supply, German TSOs activated all balancing reserves as well as interruptible loads in Germany. Yet these measures were still not sufficient. Figure 21 below shows how the system imbalance (dotted line in red) evolved during these days and which reserves and complementary instruments were activated by TSOs.

Imbalance in system balancing (MW)

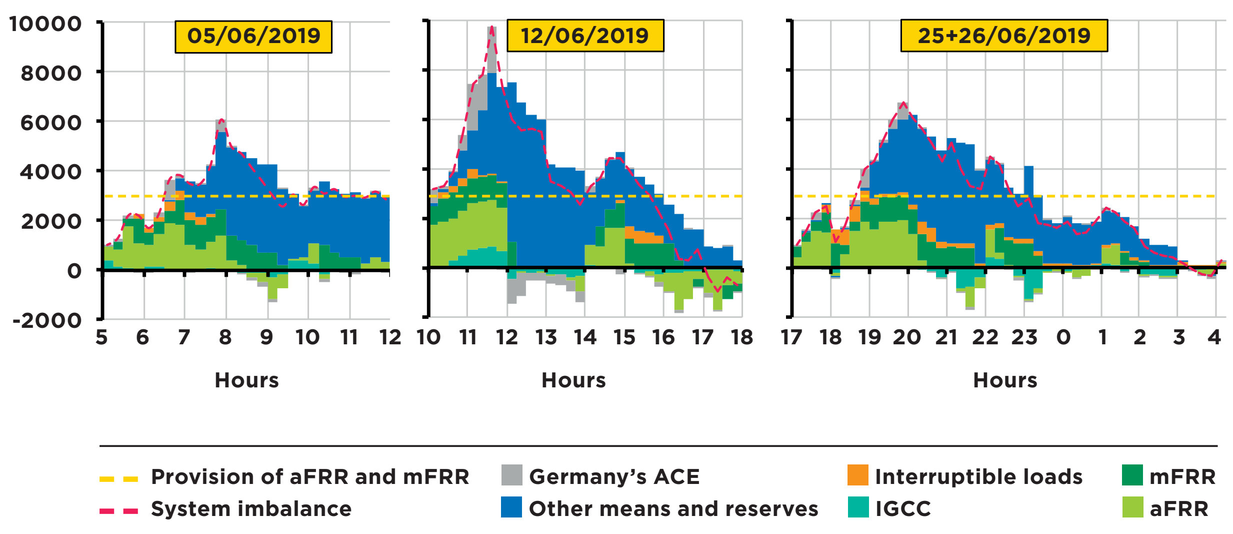


Figure 21: Development of the system imbalances and measures implemented by German TSOs on 06/06/2019, 12/06/2019 and 25+26/06/2019[45], source: analysis by German TSOs[46]

[45] *The numbers shown are average values per quarter hour, while higher peak values were observed during some quarter hours.*

[46] *See https://www.regelleistung.net/ext/download/STUDIE_JUNI2019*

Besides the activation of balancing reserves **(aFRR** and **mFRR)** and **interruptible loads**, the German TSOs activated additional reserves from other sources **(other means and reserves)**, including purchases of scheduled energy on the power exchange's continuous Intraday (ID) market and emergency reserves delivered by several foreign TSOs. The red dotted line in Figure 21 shows the **system imbalance** which is calculated as the sum of all adopted measures. It can be interpreted as the theoretical maximum system imbalance. Yet this theoretical maximum system imbalance did not occur in reality, because the remaining control error **(ACE)** of the German load frequency control block was able to be reduced by netting its imbalance with other load frequency control blocks (e.g. France).[47]

In summary, there was a significant risk to system stability and security of supply in Germany. System stability could only be restored through the massive and coordinated deployment of measures taken by TSOs for several hours. The need for system balancing would have been even higher, if the imbalances had not been partially offset by opposite imbalances elsewhere.

INVESTIGATION OF CIRCUMSTANCES AND CAUSES OF THE SYSTEM IMBALANCES

German TSOs carried out a quantitative analysis of the circumstances and causes leading to the dramatic situations observed in June 2019.[48] In the following, the main findings are summarised.

On 06/06/2019 and 12/06/2019, complex weather conditions led to difficulties in predicting the renewable energy (RE) generation, in particular wind generation. On 25/06/2019, no such significant RE forecast errors were observed.

Furthermore, during all three days, low imbalance prices – partially below the maximum intraday market prices (> 500 €/MWh) – provided for limited incentives to balance responsible parties (BRPs)[49] to keep a balanced portfolio. This is a key reason for the BRPs imbalances and the system imbalance observed, in addition to RE generation forecast inaccuracies.

The evaluation of BRPs transactions suggests that only a few BRPs with high imbalances had a significant share in the system's total imbalance. For instance, on 25/06/2019, the five BRPs with the largest imbalances contributed about 2,000 MW to the overall system imbalance of approx. 6,000 MW. Looking at the imbalances of the 20 most imbalanced BRPs, these corresponded to approximately 4,000 MW.

On the other hand, the analysis carried out by German TSOs shows that BRPs managed their balancing groups properly, as far as schedule notifications and transactions on the day-ahead market are concerned. But some of them switched to improper balancing group management and intraday schedule notifications, causing high imbalances in this time frame. They adjusted considerably their schedule notifications shortly before the start of delivery. The BRP adjustments correlate with the high prices in the continuous intraday market for scheduled energy and low imbalance prices (i.e. incentives to BRPs), while they may be justified by renewable generation forecast errors only to a limited extent.

[47] *In Figure 20, this netting is shown as IGCC (Internal Grid Control Cooperation) quantities. The IGCC is a cooperation between TSOs which deal exclusively with imbalance netting for automatic Frequency Restoration Reserves (i.e. to avoid counter-activation of aFRR in different control areas) under residual ATC constraints at the borders to provide operational security.*

[48] *The detailed report can be found at https://www.regelleistung.net/ext/download/STUDIE_JUNI2019*

[49] *The balance responsible party shall be responsible for a balanced quarter-hour performance balance of the feed-ins and draw-offs allocated to their balancing group, for a proper schedule management and the economic balancing of remaining balance deviations.*

CONSEQUENCES

German TSOs deepened their BRP imbalance analysis to investigate the suspicion of improper BRP management, breach of forecast duty and short-selling. TSOs informed the German National Regulatory Authority Bundesnetzagentur (BNetzA) about the results of their investigation by the end of September 2019 and handed out a list of conspicuous BRPs and supportive data. These results might support further procedures against the concerned BRPs by the TSOs and the BNetzA.

As a consequence of these events and the available preliminary results, various measures were implemented or scheduled. Inter alia, more balancing capacity (mFRR) was contracted.

Apart from that, the TSOs recommended some regulatory adjustments to increase the incentives to BRPs to remain balanced.[50] In November 2019, BNetzA decided to follow the TSOs' recommendation in order to reduce risks for security of supply and to eliminate adverse incentives in imbalance pricing.[51] Furthermore, BNetzA opened legal procedures against six BRPs due to improper balancing group management.[52]

[50] Those incentives include an obligation for BRPs to remain balanced at all times including intraday, the adjustment of the 80% criterion and consideration of ID market prices of quarter-hour products for determining the imbalance pricing and the provision of meter data for large consumers to the TSO on D+1.

[51] See https://www.bundesnetzagentur.de/SharedDocs/Pressemitteilungen/DE/2019/20191211_Bilanzkreistreue.html?nn=265778

[52] See https://www.bundesnetzagentur.de/SharedDocs/Pressemitteilungen/DE/2019/20191022_BK6.html

AMPRION MARKET REPORT 2020

6. FUTURE DEVELOPMENTS AND TSO COOPERATIONS

AMPRION CONTINUES TO SUPPORT THE EUROPEAN ENERGY MARKET.

6.1 CLEAN ENERGY PACKAGE

An adequately developed electricity grid is the only way to realise a functioning and integrated European electricity market and achieve Europe's ambitious energy and climate targets.

LEGAL BACKGROUND

The 'Clean Energy for All Europeans Package' entered into force on 4 July 2019. As one of the main provisions of the Regulation (EU) 2019/943 on the internal market for electricity (EU Electricity Regulation), at least 70% of the capacity of internal and cross-zonal critical network elements has to be made available for cross-zonal electricity trading from 1 January 2020 (Article 16(8)).

Germany, as well as Poland and the Netherlands, has opted for an exemption clause, a so-called 'Action Plan' according to Article 15 of the EU Electricity Regulation. The Action Plan foresees that the trading capacity will be increased based on a linear trajectory to 70% by 31 December 2025.

IMPLEMENTATION OF THE NEW PROVISIONS

Based on the guiding principles for calculating the starting points[53] published by the BNetzA, the German TSOs have calculated starting points for the linear trajectory applied to the German bidding zone borders, respectively critical network elements. For all bidding zone borders, respectively critical network elements, which will be a future part of the flow-based market coupling in the capacity calculation region Core (Core FB MC), one common average starting point value was determined. Until the go-live of the Core FB MC, this starting point will be applied in the CWE region as well as the NTC borders, which will be part of the Core FB MC.

[53] *Published on https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Handelund Vertrieb/EuropMarktkopplung/MarketCoupling_node.html*

Table 2 illustrates the results of these calculations:

	% of the capacity of critical network elements (CNE)						
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**From 31/12/2025**
German CNECs in Core	11.5	21.3	31.0	40.8	50.5	60.3	70.0

Table 2: Percentage of the capacity of critical network elements (CNECs) for Germany in the CCR Core

Germany has implemented these values, following the new provisions as of 1 of January 2020.[54] The new capacity targets do not undermine current minimum trading capacity provisions. Amprion supports the 20% minimum capacity value (CWE-minRAM) introduced in the CWE region in April 2018, which will be guaranteed for German CWE network elements in compliance with system security standards. By doing so, Germany goes beyond legal requirements and sends a strong signal to guarantee reliability and dependability for electricity market participants.

IMPACT OF THE NEW PROVISIONS

The provisions mentioned above will have major impacts on the cross-zonal electricity trading in Europe. Amprion fully supports the further optimisation of the use of trading capacities. Yet the introduction of a lump-sum target value may have adverse technical and economic impacts.

As illustrated in the beginning of the report, Amprion has a large number of cross-border interconnectors. For technical and operational reasons (n–1 principle, controllability of load flows in the AC grid, loop flows), the thermal capacity of these interconnectors can never be fully utilised for cross-zonal electricity trading. Therefore, the introduction of an arbitrarily chosen 70% lump-sum trading target on all network elements can only be achieved by extensive operational measures, in particular the use of redispatching.

THIS LEADS TO IMPLICATIONS ON SEVERAL ASPECTS:

- **System security challenges:** The forced, modified use of power plants (redispatching) is inherently accompanied by specific system security challenges. Power plants already activated for preventive redispatch would no longer be available for congestion management measures during the real-time system operation, e.g. for critical grid situations resulting from power plant outages or grid disturbances. Even today, without this additional demand for redispatching measures, there is already insufficient capacity available for redispatching in some cases. This trend will most likely be reinforced in the coming years by further decommissioning of thermal power plants.

[54] *Some TSOs decided to require a derogation. The submitted derogations by Core TSOs can be found here: https://www.entsoe.eu/network_codes/ccr-regions/#core*

AMPRION MARKET REPORT 2020

- **Economically suboptimal market result**: It can be assumed that high redispatch activities and costs will be necessary to achieve the 70% target. Traders will profit from the increased trading possibilities, while the corresponding high redispatch costs will be borne by grid users via the grid tariffs. Such redistributive effects can become very significant.

- **Disincentives for network expansion:** The negative effects of the arbitrarily chosen 70% lump-sum trading target described above increases the operational risk exposure for TSOs investing in interconnectors. The paradoxical consequence is that the 70% target may, in the long-term, hinder rather than promote European electricity market integration and thus the achievement of the goals of the EU Commission.

- **Discrimination of exporting countries:** Due to the 70% target, cross-zonal electricity trading tends to be prioritised over internal zonal electricity trading. The grid of an exporting country has to carry both the flows for its own internal supply and, in addition, guarantee 70% for exports to other countries. In contrast, an importing country has to carry only partially the flows for its internal supply since parts are covered by imports which are included in the 70% target. Therefore, its network tends to be less used in comparison to an exporting country, which has to expand its grid to also supply the neighbouring countries with electricity. As a consequence, grid users of exporting countries tend to subsidise grid users of importing countries. The same applies to grid users of transit countries.

It can be expected that the implementation of the arbitrarily chosen 70% lump-sum trading target will increase the cross-zonal electricity trading in the coming years. This per se positive development is dearly bought by higher system costs for the European people, negative implications on system security and disincentives for further European market integration in the long-term. In particular, the welfare impact of the mandatory 70% must be assessed in terms of the total system costs, as these costs have to be paid in full by the consumers. The focus should not only rely on the welfare created in the market, but also needs to take into account the costs of securing the grid. Although the 70% will increase electricity trading, it is to be expected that the additional costs for congestion management will outweigh the increased market welfare. Instead, it is likely that the total welfare (considering electricity markets and grid operation) will be maximised with a much lower percentage than the chosen 70%. Further research work is needed in order to determine the value that most likely leads to a welfare optimum.

Amprion wants to encourage legislators to put physics first and provide a strong backbone with a proper legal framework for a functioning electricity market. In the long-term, it will become clear that an adequately developed electricity grid is the only way to realise a functioning and integrated European electricity market and achieve Europe's ambitious energy and climate targets.

6.2 FOCUS ON FCR COOPERATION

TSOs' voluntary FCR Cooperation can avoid costs up to € 100 million per year

Amprion is party to numerous cooperation agreements with European TSOs with whom we are working closely to enhance the safety, reliability and capability of our grids. Our focus is on system reliability and grid planning, the European electricity market and further development of transmission technologies.[55]

One example is the FCR (Frequency Containment Reserves) Cooperation. The FCR Cooperation is an association of different transmission system operators (TSO), aiming to commonly procure the required FCR capacity according to System Operation Regulation (Regulation (EU) 1485/2017).

[55] *See for further information: https://www.amprion.net/Amprion/European-responsibilities/European-Cooperations/*

Since December 2007, the four German TSOs have already been cooperating in the procurement of FCR capacity. With the accession of Switzerland to this cooperation in 2012, a common procurement on national level became the first international balancing capacity procurement in Europe. In the following years from 2014 to 2017, the Netherlands, Austria, Belgium and France joined the FCR Cooperation. An upcoming extension of Western Denmark and Slovenia is foreseen and welcomed by all TSOs and National Regulatory Authorities involved.

After entry into force of the Electricity Balancing Regulation (Regulation (EU) 2195/2017) in December 2017, the regulatory framework for regional balancing capacity procurement was harmonised, while any cooperation remained completely voluntary. In this way, the TSOs of the FCR Cooperation established a joint balancing capacity market for FCR capacity before any regulatory requirement was put in place.

The coupling of the FCR capacity markets has created the largest FCR market in Europe with higher liquidity for the procuring TSOs. Currently, 1,374 MW (from June 2020 onwards 1,413 MW) of 3,000 MW (i.e. 46%) of the entire continental European FCR capacity (3,000 MW) are procured jointly within the cooperation.

The aim of this common procurement is to reduce the costs of covering FCR demand. This goal was already able to be reached when pay-as-bid was used as the pricing system in the cooperation and is in the same way valid for marginal pricing, which was introduced in July 2019. The following figure shows an analysis for the period from July 2019 to December 2019 and proves that this aim has been achieved.

Overall costs of daily FCR procurement with/without cross-border exchange

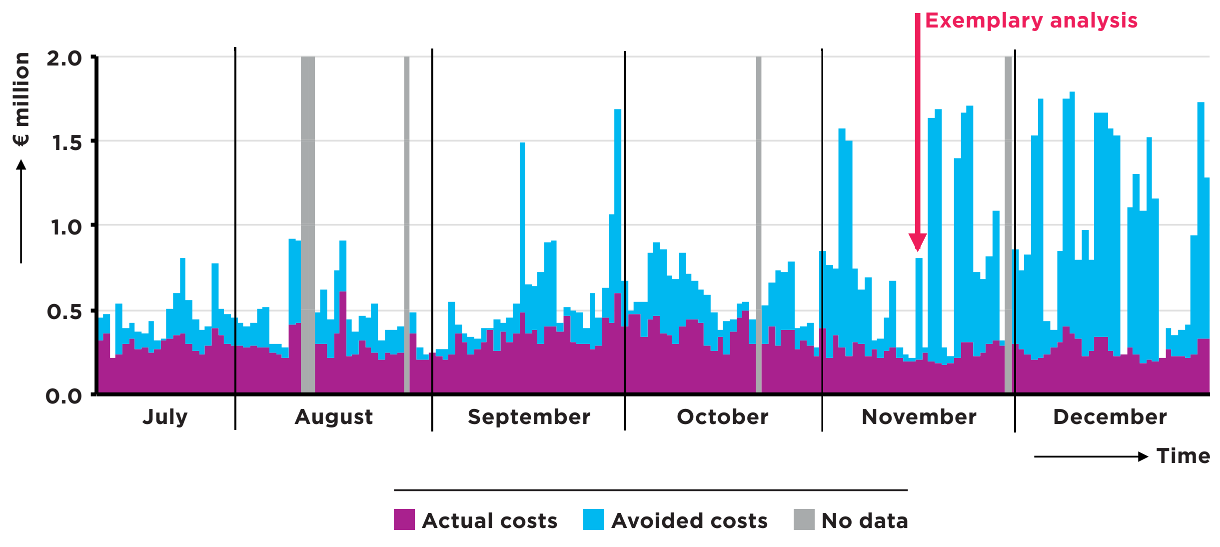


Figure 22: Comparison of actual and avoided costs in procurement with and without the FCR Cooperation in 2019

Figure 22 compares the costs of the FCR capacity procurement since the implementation of marginal pricing in July 2019 with cooperation (actual costs) with the potential costs without FCR Cooperation (actual cost + avoided costs). Obviously, the cooperation in the procurement of the FCR demands leads to a significant avoidance of costs. Based on the analysed data of the second semester of 2019 (after introducing marginal pricing in the cooperation), costs up to € 100 million per year can be avoided. The international FCR Cooperation leads to an overall benefit of approximately 40% (compared to procurement without the international cooperation).

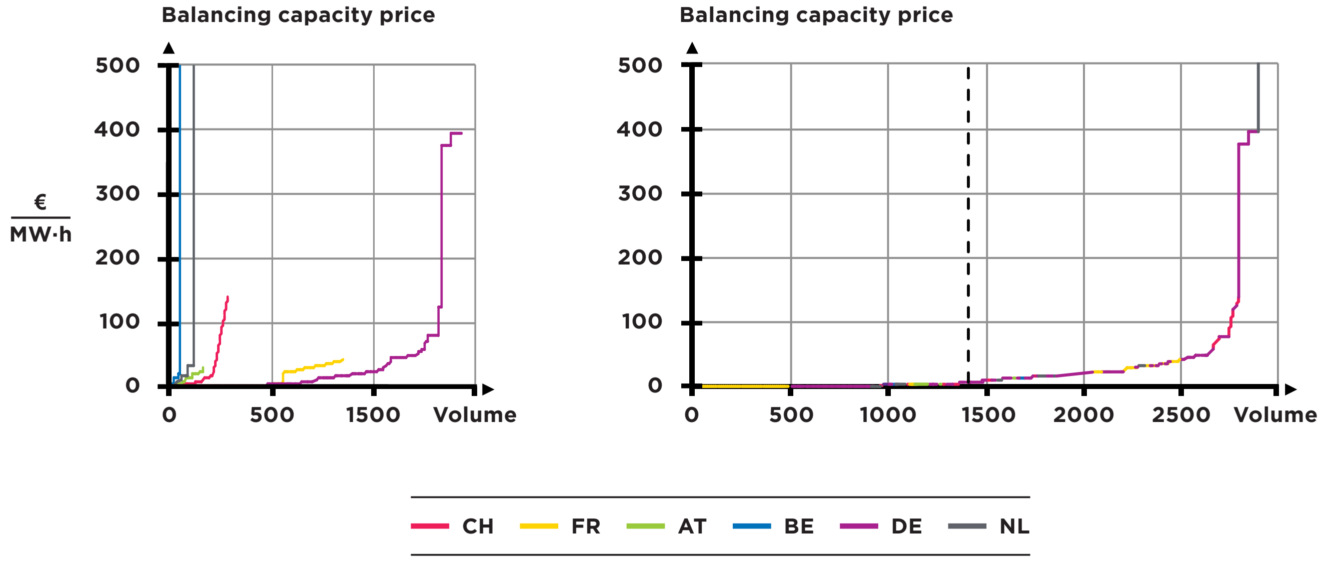


Figure 23: Exemplary structure of single and common merit order lists on 16 of November 2019

Figure 23 shows the country-specific, single merit order lists (left figure) and the common merit order (right figure) of the FCR Cooperation on 16 November 2019. Considering single merit order lists, the FCR capacity markets clear at significantly higher local marginal prices in some countries as the single countries also need to procure bids with high prices in the merit order list. By merging the offers in a common merit order list (as in the FCR Cooperation), the significantly more expensive offers are procured less frequently as they are shifted to the right edge of the merit order, so that the costs within the framework of marginal pricing are significantly reduced. In this figure, the dotted line shows the current commonly procured amount of FCR (1374 MW) in the FCR Cooperation and visualises that the demand can mainly be covered by the lower prices on the left side of the merit order.

6.3 ACCELERATED GRID DEVELOPMENT AND ENHANCEMENT IS KEY

Further development and improvement of the existing electricity grid is the core business of TSOs, and in particular an increase in transmission capacity, reduction in congestions and enhancement of trading capabilities. In 2020 and beyond, Amprion will support cross-zonal trading by taking several additional measures.

FURTHER DEVELOPMENT OF THE DYNAMIC LINE RATING

Amprion introduced dynamic line rating on its transmission lines, allowing adaptive maximum thermal capacities (Fmax) as a function of weather conditions, i.e. temperature. Through this measure, thermal limits can be increased by more than 20%, in particular during cold weather conditions usually associated with a high electricity demand.

When introducing the dynamic line rating concept, priority has been given to those internal circuits that appeared as critical branches in the CWE flow-based market coupling.

For this reason, in March 2019 the dynamic line rating was introduced on the Emsland transmission lines (Dörpen–Hanekenfähr) between Tennet DE and Amprion. This route forms the crucial connection of the offshore HVDC (high-voltage direct current) converters in Dörpen to the AC grid in North Rhine-Westphalia. By increasing the maximum transmission capacity of the Emsland line by 25%, the need for redispatching was significantly reduced, and so, too, was the unavailability of offshore wind infeed.

In order to improve the impact of the weather-dependent operation of overhead lines on capacity and redispatch reduction, the next phase of the dynamic line rating concept has already been initiated. For this purpose, in 2019, Amprion installed 16 additional weather stations located along the most heavily loaded circuits at meteorologically exposed locations (i.e. pylons and substations). There are plans to install 200 weather stations by the end of 2022.

In order to be able to parameterise this information on the network models for congestion management processes, weather forecasts must be available based on of the measured weather data with a lead time of seven days. Wind forecasts still contain considerable uncertainties. This must be taken into account when releasing thermal overload capabilities. Due to the lead time when calling thermal power plants, an operational decision must be made despite this uncertainty in the forecast. These issues are currently clarified together with Fraunhofer IEE. This project will support Amprion in optimising the processes for dynamic line rating and in doing so supports the integration of the European electricity market.

ALEGRO: FIRST NEW INTERCONNECTOR BETWEEN GERMANY AND BELGIUM

Amprion and the Belgian TSO Elia are constructing the first transmission line between Germany and Belgium. The project known as ALEGrO uses HVDC transmission technology and, with a transmission capacity of 1,000 MW, contributes significantly to an increase in cross-zonal electricity flows in Central Europe. At the same time, ALEGrO will strengthen the security of supply in the Aachen-Cologne region in Germany. With ALEGrO, Amprion is therefore supporting the integration of the European electricity market significantly. The construction works for ALEGrO began in 2018 and, according to current planning, ALEGrO will be commissioned by the end of 2020.

The ALEGrO project, the first of its kind between Germany and Belgium, is also known as the 'Aachen Liège Electricity Grid Overlay' (ALEGrO). With a transmission capacity of 1,000 MW, ALEGrO provides crucial grid capacities for cross-zonal flows. The project is part of the Trans-European Networks for Energy (TEN-E) program and has also been included in the European Union's list of 'PCI projects' – as a 'project of common interest' urgently in need of implementation. Germany's legislators have also recognised this need and added the project to the Federal Requirements Plan Act (BBPlG) as Project No. 30.

Figure 24 provides an overview of the HVDC technology used for ALEGrO, which will be installed as an underground cable.

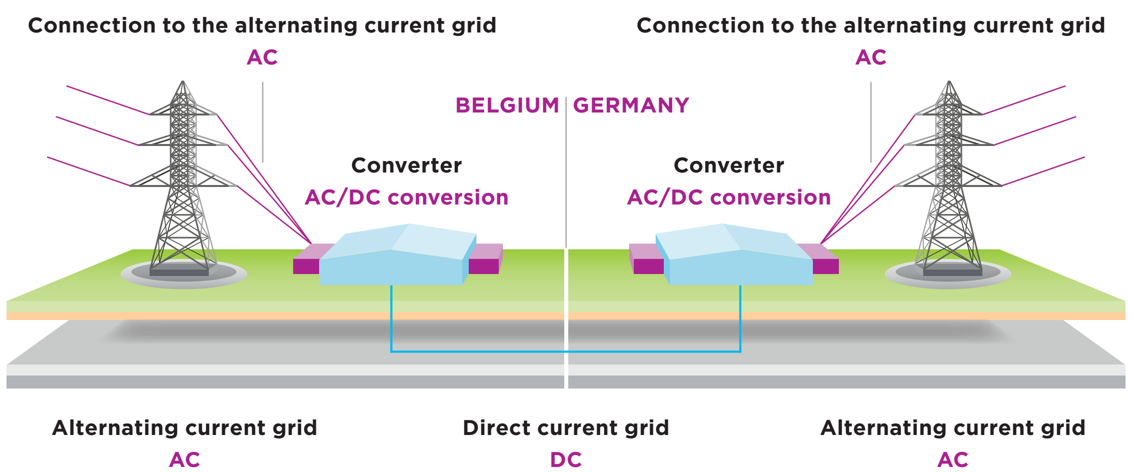


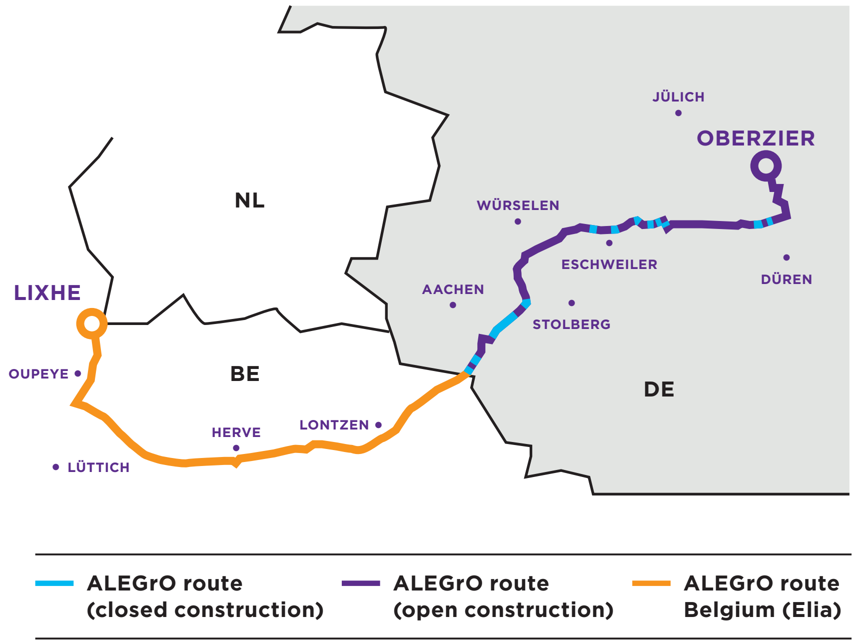
Figure 24: DC technology for ALEGrO

TECHNOLOGY AND ROUTE

The HVDC link requires a converter station at each end of the line to convert the alternating current to direct current and vice versa. The link is being planned as an underground cable route between the existing 380-kilovolt stations located in Oberzier in Germany (Amprion) and Lixhe in Belgium (Elia) and it will be approximately 90 kilometres long. The German section will account for around 41 kilometres. The underground DC cable of ALEGrO will be connected to the German and Belgian AC grids by means of two converter stations – one at either end. Figure 25 shows the planned route between Oberzier (Germany) and Lixhe (Belgium).

PLANNED ROUTE GUIDANCE

Figure 25: Planned route for the approximately 90-kilometre-long ALEGrO transmission line between Germany and Belgium



FURTHER MEASUREMENTS TO INCREASE THE CAPACITY OF THE CURRENT GRID

In 2019, Amprion launched its first hybrid power station in Kriftel near Frankfurt, consisting of an MSCDN[56] and a STATCOM[57]. The hybrid station allows dynamic regulation of voltage and reactive power in order to stabilise the regional and national power grid. With a capacity of –300 to +300 MVar, Amprion has built the most powerful unit in Europe. Moreover, Amprion also commissioned a rotating phase shifter in Uchtelfangen near Saarbrücken in 2019 for the same purpose.

By regulating the dynamic voltage and reactive power, Amprion enables secure operation of the system by allowing higher flows. Thus, Amprion contributes to a higher utilisation of the current grid infrastructure and helps to decrease internal bottlenecks.

FUTURE PROJECTS TO SUPPORT THE EUROPEAN ENERGY MARKET AND TO DECREASE INTERNAL GRID CONGESTIONS IN GERMANY

Amprion is supporting the market by strengthening and extending its grid infrastructure for more than 1,500 km in the next ten years. Two of Amprion's lighthouse projects are HVDC links from Emden in Northern Germany to Osterath in Western Germany and from Osterath to Philippsburg in Southern Germany. These projects are known as A-Nord and Ultranet from Corridor A, one of the future main arteries in the German transmission grid. Both projects are legally defined in the Federal Requirement Plan Act[58]. The approval procedures for defining a corridor and the specific route for the lines proceeded in 2019. While A-Nord is planned as an underground cable system, Ultranet is planned as a hybrid system by using the same pylons for AC and DC current.

Considering future developments in the German and European energy system until 2030, results of the recent national development plan in 2019 highlight the need for an additional DC corridor from Northern Germany to Western Germany by 2030 (Corridor B). Amprion already started the initial steps to develop the corridor in 2019. Figure 26 shows all DC projects of Amprion.

Amprion plans grid investments of € 15.2 billion over the next ten years.

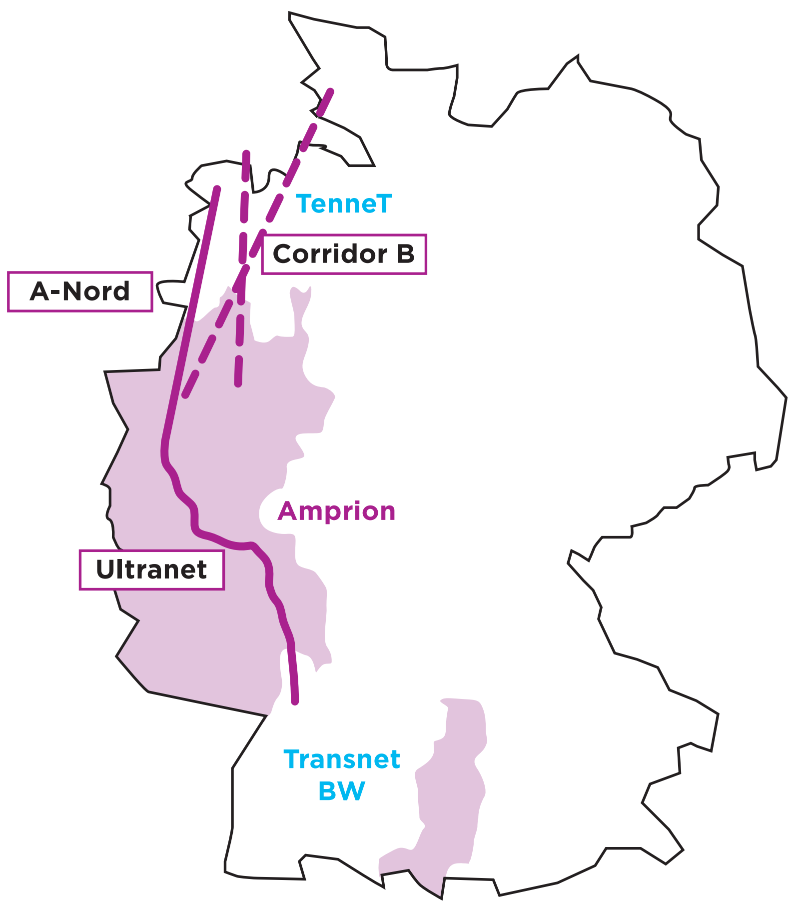


Figure 26: Planned DC projects by Amprion

[56] *MSCDN: Mechanical Switched Capacitor with Damping Network*

[57] *STATCOM: Static Synchronous Compensator*

[58] *The Federal Requirements Plan Act lists the transmission projects that are legally defined through the German parliament. The German TSOs are obliged to implement these projects.*

AMPRION MARKET REPORT 2020

AMPRION MARKET REPORT 2020

7. CONCLUSION AND OUTLOOK

THE CURRENT DYNAMIC DEVELOPMENTS IN THE ELECTRICITY SYSTEM AND MARKET WILL CONTINUE OVER THE NEXT DECADES.

This Market Report provides evidence of the dynamic electricity market environment in which Amprion operates together with many other institutions. It starts with an illustration of current and future changes in the electricity production pattern. Current electricity market trends are analysed where regulatory changes have led to a changing market behaviour. During a few summer months of 2019, Germany became a net electricity importer. During winter periods with prevailing exports, Amprion and its neighbouring TSOs had to change the market-based dispatch of generators (redispatching) in order to ensure safe and secure grid operation. Nevertheless, we were able to reduce the grid-related market constraints accommodating further integration and higher price convergence in the entire Western European market. Some extraordinary market events occurred in 2019. The report contains a description of these events which were successfully managed by Amprion and its partner TSOs.

The current dynamic developments will persist into the future. To accommodate the changing generation pattern, to facilitate the integration of renewables into the system and to ensure the physical transmission of increasing market flows across Germany and Europe, Amprion is continuously enhancing its grid. The new interconnector ALEGrO is currently being built between Germany and Belgium, and is scheduled to become operational in 2020. It will be able to transmit 1,000 MW between those two countries. The project applies new onshore direct current (DC) transmission technologies and has been formally declared a Project of Common European Interest.

In terms of market integration, Amprion will continue its strong commitment to the ongoing activities in the capacity calculation regions CWE and Core (the latter consisting of the previously separated regions CWE and CEE[59]). This will encompass the implementation of a flow-based capacity calculation and allocation at all Core borders for the day-ahead (and at a later stage intraday) time frame and long-term capacity calculation. Concepts of organising and further enhancing cross-zonal redispatch and sharing of the related costs amongst TSOs are currently being developed. We are confident that the current close cooperation amongst all involved TSOs and regulatory authorities will result in adequate and acceptable solutions for all parties involved.

Recently released European legislation – the Clean Energy Package – contains ambitious targets for European electricity trading. Amprion and all other European TSOs will have to make 70% of transmission capacities exclusively available for European cross-border trade. This requirement will impose specific challenges on our system operation. Although the implementation of the arbitrarily chosen 70% target will increase cross-zonal electricity trading, this per se positive development is dearly bought by higher costs for securing the grid. The total welfare impact of the 70% value must be further analysed in dedicated studies, considering not only the positive market impacts, but also the related additional measures for maintaining grid security as these costs have to be paid by consumers as well. It is likely that the welfare-optimal value (considering electricity markets and grid operation) will be below the chosen 70%. To be even more explicit, a value above that which is maximising the total welfare will in fact decrease the overall welfare for Europe.

Beyond the near future, the European objective of becoming climate-neutral by 2050 and the related European Green Deal requires a fundamental transformation of the European energy system. Amprion and all other European TSOs will have to ensure that an increasing share of volatile renewables is integrated while at the same time guaranteeing security of supply, which requires the availability of sufficient reserves.

As the strong and interconnected power grids secure a balanced and stable power system across Europe, strengthening competition and reducing prices, the extension, reinforcement and optimisation of the power grids are a crucial prerequisite for successful and efficient integration of renewables. To achieve this goal, besides creating greater local acceptance for timely implementation of infrastructure projects, a proper framework and investments are needed.

The envisaged expansion of renewables will not be sufficient by itself and the electrical energy system of today will, however, meet its limits. More flexibility, for example through seasonal storage and innovative concepts such as sector coupling and integration, is needed to make the energy system fit and decarbonised for the future. Here, the TSOs can also be important enablers and market integrators for the energy transition process, as they can use such instruments in a targeted and thus efficient manner.

The increasingly coupled energy system is a strong driver for decarbonisation efforts in other sectors and requires coherent infrastructure planning at national, regional and European level. The European grid should be jointly planned in the future by the electricity and gas TSOs.

Security of supply, sustainability and costs must be reconciled. In order to ensure a further reduction of CO_2 emissions in line with the EU targets, while maintaining Europe's security of supply and industrial competitiveness, cross-sectoral approaches and technology diversity and neutrality, as well as flexible regulation are required. The EU legal framework should be used here to support pilot plants and sandbox projects. Since innovation requires a timely setting of a stable framework and the right incentives, an appropriate legal framework needs to be set up.

[59] CEE: Central Eastern Europe

APPENDIX

AS ANNEX TO SECTION 2.2: THE APPROPRIATE DETERMINATION OF INPUT PARAMETERS IS CRUCIAL

To calculate flow-based capacities, TSOs have to prepare several inputs used in the capacity calculation process. Fundamentally, TSOs consider best estimates of the state of the CWE electric system containing forecasts with regard to grid topology, generation and load. In particular, generation and load assumptions can considerably impact the system state and therefore determine the active constraints and corresponding exchange capabilities.

Moreover, TSOs have to determine parameters for the relevant critical network elements, i.e. maximum current on a critical network element (Imax) and Flow Reliability Margins (FRM). In order to map changes in net positions to the generating units in a bidding zone, Generation Shift Keys (GSK) are defined. To ensure secure power system operation, TSOs take into account remedial actions during capacity calculation, e.g. change of the tap position of a phase shifter transformer or other topological measures.

Another important parameter in the FB MC capacity allocation is the consideration of so-called phase shifter transformers (PSTs). Phase shifters are grid elements which help the TSOs to handle the flows. By changing the PST tap position, load flows and therefore potential congestion are reduced and allow the TSOs to offer more capacity to the market parties. The impact of the PSTs is not limited to the area surrounding the PSTs but the effects can be seen on the overall European network. The coordination of these devices is a key process of the D-2 flow-based capacity calculation in CWE to enlarge the flow-based domain (or in other words: to enlarge the trading possibilities) while respecting security of supply. Against this background, the assumptions taken for the position of all phase shifters during the FB MC are a major parameter to the FB MC outcome.

AS ANNEX TO SECTION 3.2: EXCURSUS: INTUITIVE PATCH DECREASES SOCIAL WELFARE OF FLOW-BASED MARKET COUPLING

An explanatory example:

The 'plain'[60] FB market coupling could result in a situation in which Germany (DE/LU) exports to the Netherlands, although the day-ahead price in Germany exceeds the price in the Netherlands. At first glance, this situation is not intuitive as one would expect that electricity is exported from the low-price zone to the high-price zone. Yet, considering all exchanges in the CWE region, such a situation can still be optimal for social welfare. This could be the case, if, for example, the Netherlands were to further export to the high-price bidding zone Belgium. Please find below an illustrative example.

[60] i.e. the FB MC without any additional constraint (patch) to ensure intuitiveness of the results

PLAIN FB MC RESULTS

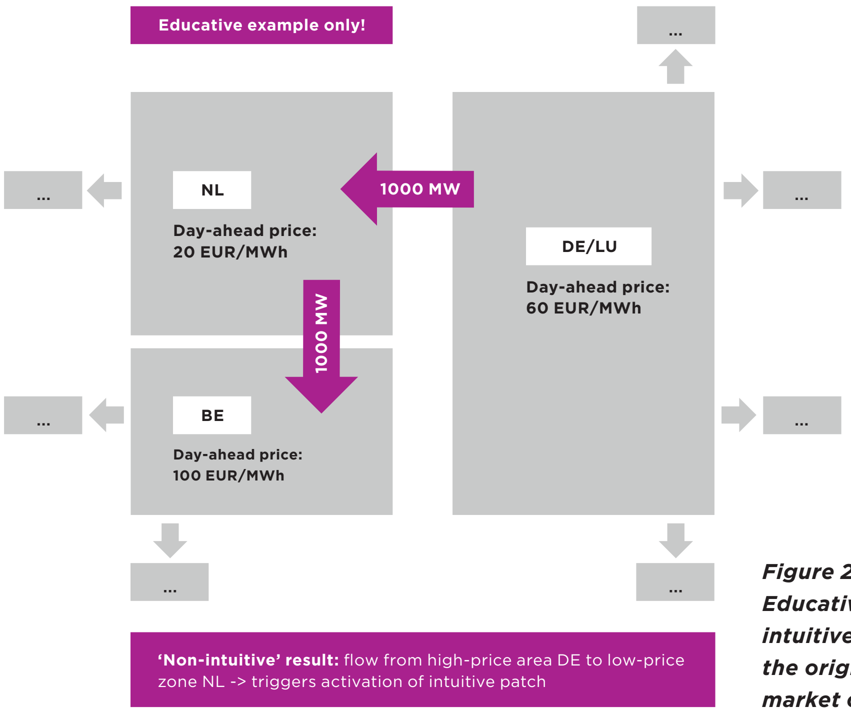


Figure 27: Educative example for intuitive patch showing the original flow-based market coupling results

FB MC RESULTS AFTER APPLICATION OF THE INTUITIVE PATCH

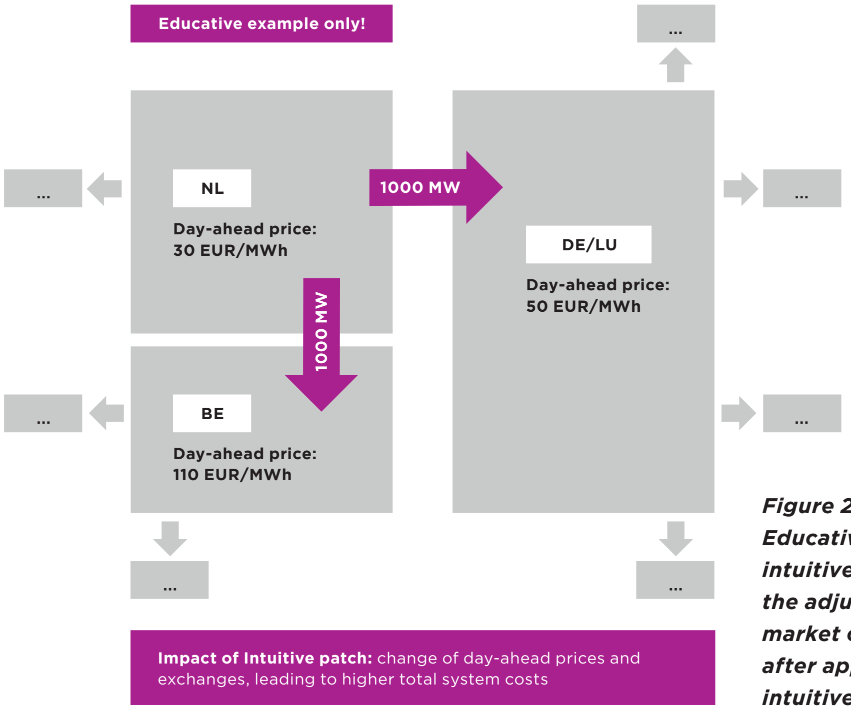


Figure 28: Educative example for intuitive patch showing the adjusted flow-based market coupling results after application of the intuitive patch

AMPRION MARKET REPORT 2020

LIST OF ABBREVIATIONS

ACER	Agency for the Cooperation of Energy Regulators
ALEGrO	Aachen Liège Electricity Grid Overlay
BNetzA	Bundesnetzagentur
BRP	Balance Responsible Party
CB	Critical Branch
CBCO	Critical Branch Critical Outage
CCM	Capacity Calculation Methodology
CCR	Capacity Calculation Region
CEE	Central Eastern Europe
CNE	Critical Network Element
CNEC	Critical Network Element and Contingencies
CWE	Central Western Europe
DA	Day-Ahead
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
FAV	Final Adjustment Value
FB MC	Flow-Based Market Coupling
FCR	Frequency Containment Reserves
Fmax	Maximum Allowable Power Flow
Fref	Reference Flow
FRM	Flow Reliability Margin
GSK	Generation Shift Key
HVDC	High-Voltage Direct Current
ID	Intraday
IGCC	Internal Grid Control Cooperation
Imax	Maximum Current on a Critical Network Element
LOLE	Loss of Load Expectation
LTA	Long-Term Allocation
MAF	Midterm Adequacy Forecast
MSCDN	Mechanical Switched Capacitor with Damping Network
NEMO	Nominated Electricity Market Operator
NRA	National Regulatory Authority
NTC	Net Transfer Capacity
OTC	Over the Counter
PCI	Project of Common Interest
PST	Phase Shifter Transformer
PTDFs	Power Transfer Distribution Factors
RAM	Remaining Available Margin
RE	Renewable Energy
SIDC	Single Intraday Coupling
STATCOM	Static Synchronous Compensator
TEN-E	Trans-European Networks for Energy
TSO	Transmission System Operator
XBID	Cross-Border Intraday Project

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