Commissie voor de Regulering
van de Elektriciteit en het Gas

CREG

Study

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Study on the functioning and price evolution of the Belgian wholesale electricity market – Monitoring Report 2021

Done in accordance with article 23, §2, second paragraph, 2° and 19° of the law of 29 April 1999 on the organization of the electricity market

Non-confidential

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INTRODUCTION

In this study, the COMMISSION FOR ELECTRICITY AND GAS REGULATION ("CREG") presents its findings with regards to the monitoring of the functioning and price evolution of the Belgian wholesale markets for electricity. The focus of this study is the evolution of the Belgian electricity markets in 2021. Where available, historic data dating back to 2015 are presented.

This study is divided in 8 different chapters:

- the first chapter presents the electricity load and consumption;
- the second chapter focuses on electricity generation;
- the third chapter introduces the physical import and export of electricity;
- the fourth chapter focuses on the long-term electricity markets;
- the fifth chapter describes the day-ahead markets;
- the sixth chapter covers the intraday markets;
- the seventh chapter deals with the balancing timeframes; and
- the eight chapter elaborates on non-balancing ancillary services.

The main findings of the individual chapters are summarized in the conclusion at the end of this study. At the end, the reader may find lists of abbreviations, tables and figures used throughout this study.

The Board of Directors of the CREG approved this study at its meeting held on 12 May 2022.

EXECUTIVE SUMMARY

The **total consumption of electricity** in Belgium reached 84,4 TWh in 2021. This represents a 4,1% increase from 2020 (81,1 TWh) where the total load was historically low, mainly due to the confinement measures to contain the Covid-19 pandemic, and the resulting low economic activity. In the long term, this result fits in the structural downwards trend of the annual electricity consumption (in 2015, still 88,0 TWh was consumed). This downwards trend is observed not only in Belgium, but also to a varying extent in its neighboring countries.

The highest observed (peak) load reached 13.562 MW in 2021, an increase of 218 MW compared to 2020 but in historical perspective a rather average value. The lowest observed (base) load reached 6.627 MW. These values – most notably the peak load – fluctuate strongly in function of seasonal and meteorological conditions.

These meteorological conditions continue to have an impact on the consumption of electricity: in line with observations for previous years, the impact of relatively low and high temperatures lead to an increase in the demand for electricity. This is mainly for heating and cooling purposes. This explains the typical seasonal pattern of the total load on the transmission network: on average, these values are much higher in the winter than in the summer.

The temporary decrease of the total load on the transmission network in 2020, followed by the rise back to normal levels in 2021, is also reflected in the numbers for the consumption of households and small businesses, typically connected to the distribution networks. The total consumption of electricity at the distribution level reached 50,6 TWh which represents a 3,9% increase compared to 2020.

Looking at the **generation of electricity**, the installed capacity increased further in 2021, confirming an upward trend since 2015, to 25,7 GW in Belgium. This increase is mainly the result of the massive deployment of wind (on- but mostly offshore) and solar photovoltaic generation. The fossil-based generation capacity also increased, while other categories remained at the same levels as previous years.

In terms of availability, nuclear power plants have shown strong numbers, moving from a full availability in only 46% of the hours in 2020 to 90% in 2021. The relatively low number of planned or unplanned outages led, in turn, to very high volumes produced from these units: 48,0 TWh (+46% since 2020). Combined with a partial reduction of electricity produced from fossil sources (19,1 TWh or -20% since) and more or less equal volumes from solar and wind sources (compared to last year), this led to a very high volume of electricity generated in general: 93,3 TWh in 2021.

Following from the increase in nuclear production and the decrease in fossil fuel-based production, the carbon intensity in Belgium reduced further in 2020 to 161 gCO2eq/kWh, representing an impressive 55% reduction since 1990.

The total volumes of **cross-border electricity flows** resulted in the highest ever recorded net export position. Subtracting the imported volumes (12,5 TWh) from the exported volumes (20,1 TWh) led to the record-breaking 7,6 TWh net export flows, aggregated across all borders. This is mostly the result of very high electricity exports to Great Britain and France, the decrease in the total load on the Belgian network and the high volumes of electricity generated.

In the **long-term markets**, prices have increased significantly since the summer of 2021, mainly fueled by the (expectations regarding further) increases in the day-ahead market prices. Notwithstanding these recent increases, market participants who purchased electricity prior to 2021 via long-term contracts (yearly, quarterly or monthly) saw far lower prices than those having to purchase the same volumes on spot markets.

Elia sells, in the yearly and monthly timeframes, its interconnection capacity on the bidding zone borders with the Netherlands, France, Germany and Great Britain. This is done in order to serve as a hedging instrument for market participants against (the volatility in) the price differences between these zones. Historically, relatively stable volumes of cross-zonal capacities have been calculated and allocated, even though the prices resulting from the auctions are not at all stable. The latter depend not only on the volume offered or the demand-side concentration, but also and more importantly on the price spreads between zones and their volatility. In particular capacity for export to France and Great Britain was very expensive in 2021 and far outside of the normal range of prices for cross-zonal capacities. This applies both to the yearly as well as to the monthly (and in the case of Nemo Link, also the quarterly) auctions. It is also worth noting that the demand for cross-zonal capacity exceeds significantly the offered volumes; depending on the timeframe and the considered border and direction, cross-zonal capacity demand was about 10 to 15 times higher than the supply in 2021.

A particular point of interest relates to the nominations of physical transmission rights on the bidding zone border between Belgium and Great Britain. Following the departure of the United Kingdom from the Internal Energy Market, no implicit coupling is in place anymore and the remuneration of long-term transmission rights was altered to reflect the initial price paid for the capacity, rather than the implicit day-ahead spread as before. This is reflected in a very high nomination rate by holders of long-term cross-zonal capacity on the Nemo Link interconnector.

The exchanged volumes in the **day-ahead markets** increased slightly in 2021 compared to the previous year: about 23,4 TWh was traded through one of the two nominated electricity market operators in Belgium. This volume represents a little more than a quarter of the total consumption of electricity. The market shares remain largely in favor of the incumbent power exchange EPEX SPOT (89,3% versus 10,7% for Nord Pool). These trades resulted in overall positive net positions in the day-ahead timeframe, reflecting the observations regarding the physical net positions: on average the Belgian bidding zone’s day-ahead net position reached +70 MW, not even including the exchanges with Great Britain (which no longer takes part in the implicit single day-ahead coupling).

Related to this observation, the CREG identified a severe increase in adverse flows over Nemo Link following the Brexit and the departure of the bidding zone Great Britain from the implicit coupling mechanisms. Estimated roughly, these adverse flows decreased welfare by about 5,6 M€ in 2021.

Even more importantly and as probably one of the most striking observations in this report, the day-ahead market prices in Belgium, but in general all over Europe, have multiplied explosively since the second half of 2021. Wholesale prices in the day-ahead timeframe have increased by about 150% from their historical average between 2015 and 2020, reaching an average value of 104,1 €/MWh in 2021.

Somewhat counterintuitively in light of the extreme price increases, the number of hours with negative prices have risen in 2021. No single bidding zone in Europe has seen as many such hours as Belgium. These negative prices result mainly from the high renewable energy generation (wind and solar), in combination with high (inflexible) nuclear output and the inability of the transmission network to export excess generation to neighboring bidding zones.

The day-ahead flow-based market coupling in the Central-Western Europe region has performed better than previous years, in line with the continuous improvements observed since the split of the German-Austrian bidding zone, the introduction of the minimum RAM requirements and the entry into force of the minimum margin requirements from the Clean Energy Package. These improvements are reflected in an increase in the available cross-zonal capacities, more price convergence between bidding zones and lower loop flows observed in the Belgian transmission network.

In the **intraday timeframe**, the continuous market coupling performed through the cross-border intraday (XBID) project has experienced an increase in number of trades as well as in exchanged volumes in 2021 compared to 2020. As in the day-ahead markets, the incumbent EPEX SPOT remains in possession of the largest market share (86,5%) while the share of Nord Pool remained stable compared to last year at 13,5%.

The hourly differences between the volume-weighted intraday reference prices and the single day-ahead clearing price increased in absolute value in 2021 compared to the previous years. The average reference prices remained, however, closely aligned, reaching 103,9 €/MWh in 2021 (against 104,1 €/MWh in the day-ahead timeframe).

Focusing on the intraday cross-border capacities, a two-step capacity calculation process exists, consisting of the calculation of an initial domain which represents the leftovers from the day-ahead timeframe. In a second step, these capacities can be increased bilaterally. Even though this system works in practice, very often low capacities are observed, in particular in the first step. In 2021, the number of occurrences where the initial intraday capacities equal zero on a certain border have increased, averaging around 40% across all borders. The increase/decrease process which is foreseen in the CWE markets may increase the available capacities, nevertheless it can be shown that the acceptance of such request has decreased in 2021. This is a particular point of attention for the CREG, as a well-functioning and liquid cross-zonal intraday market is crucial to the integration of renewable energy sources in Belgium's electricity mix.

After decreasing for several years since 2018, the total cost for the procurement of **balancing capacity** has increased in 2021, reaching 182,4 M€ for the FCR, aFRR and mFRR capacities. This can – as in other timeframes – be attributed to the steep increase in natural gas prices in 2021 and the high reliance on gas-fired units to deliver these balancing services. This factor has largely offset the positive effects which recent improvements in the procurement and market design for these capacities would have otherwise had.

In terms of **balancing energy**, 1,2 TWh from the activated resources was needed to compensate system imbalances in 2021. This equals about 1,4% of the total Belgian consumption of electricity (84,4 TWh). The largest share of these activated resources was provided through imbalance netting (42,0%).

The observed quarterly imbalances have increased in 2021. During 67,0% of the year the system imbalance ranged between -150 and +150 MW, which is 5 percentage points lower than on average in the years before. Larger imbalances, reaching more than +- 1.000 MW, were also observed during a very limited number (13) of quarter-hours. The average price for these imbalances has increased dramatically, from only 33,8 €/MWh in 2020 to 100,3 €/MWh in 2021. Depending on the direction of the imbalance, the maximum prices based on the marginal incremental or decremental price, rose to 3.200 €/MWh and -565 €/MWh respectively. The average alpha component of the imbalance price substantially increased as well, for the second year in a row, yet to a smaller extent. The impact of the redesign of this component and the resulting increase in its value did, however, not materialize (yet) in reduced system imbalances.

1. CONSUMPTION

1. The total load and load on Belgium's transmission network (grid load) increased in 2021 compared to 2020. However, the sharp decrease in 2020 was due to the exceptional and specific context of the Covid-19 pandemic and the confinement measures put in place. Thus, one should rather speak of a normalization of the grid load and total load in the context of the downward trend observed over the long term.

2. As illustrated on Figure 1-1, the total load amounted to 84,4 TWh in 2021 (i.e. a 4,1% increase compared to 2020, while the total load in 2020 decreased by 4,5% compared to 2019). The total load in 2021 thus almost returned to the pre-Covid level.

3. On the other side, the load on the transmission network amounted to 70,9 TWh in 2021, which represents an increase of 1,4% compared to 2020 (the grid load in 2020 was 5,8% lower than in 2019). Despite this small increase, the grid load still did not return to the 2019 level and cannot alone explain the increase in the total load, which reached back the 2019 level. Explanations are to be found in the relative increase in unmetered, locally consumed electricity generation, which is not included in the transmission network load but whose estimates are included in the total load.

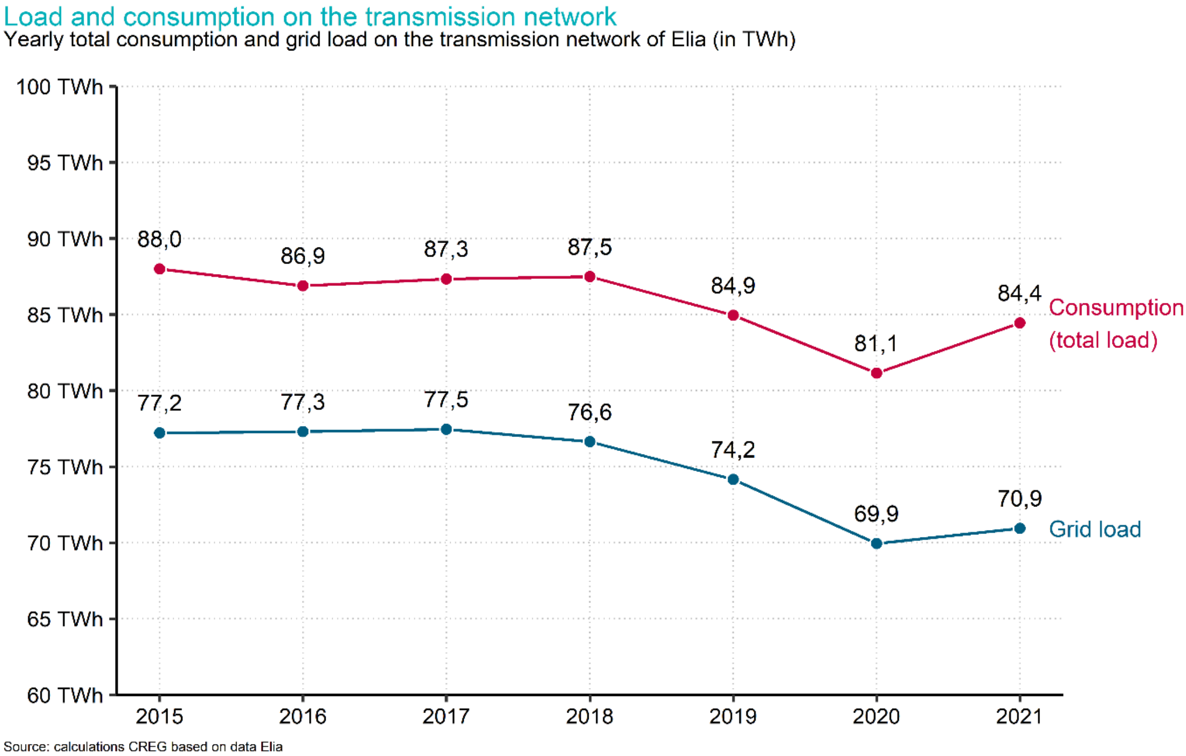


Figure 1-1 Load and consumption on the transmission network

1.1. TOTAL LOAD

1.1.1. At the European level

4. The evolution of the total electricity load in Belgium and neighbouring countries for the period 2015-2021 is illustrated in Figure 1-2. Similarly to Belgium, one can observe a downward trend over the past 5 years in the total electricity load of other European countries. This is particularly true for the Netherlands and France. On the contrary, Austria's total load is rather stable over the period.

5. For all countries except the Netherlands, the total electricity load increased in 2021 compared to 2020 and returned (at least) to the pre-Covid level. While Germany experienced a smaller reduction in its total load than any other selected country in 2020, it is the only country that registers an increase in its total load in 2021 compared to 2019. France is the country with the largest increase in its total load in 2021 (+4,8%). On the other side, the Netherland's total load has decreased in 2021 for the second year in a row, though to a lesser extent in 2021 than in 2020.

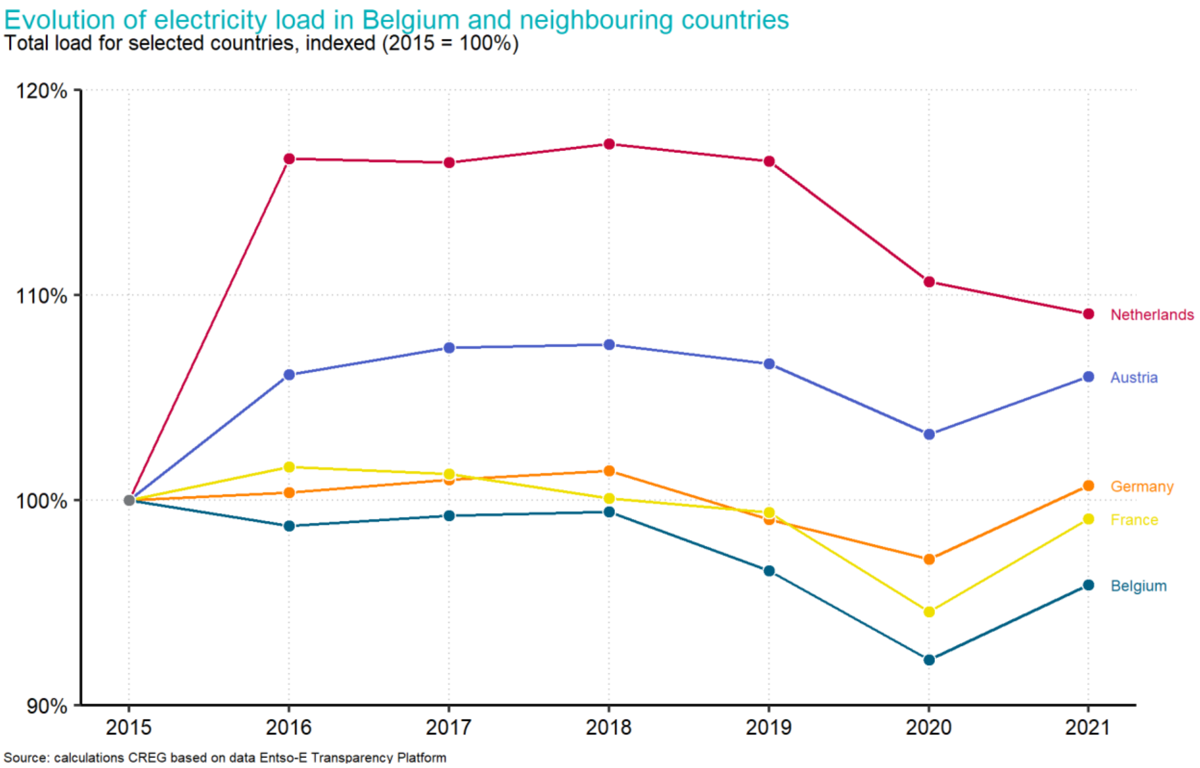


Figure 1-2 Evolution of electricity load in Belgium and neighboring countries

6. Belgium's total electricity load in 2021 amounted to 84,4 TWh, i.e. a 4,0% increase compared to 2020 (see Figure 1-3 and Figure 1-4). As far as other European countries are concerned, the total load amounted to 503,8 TWh in Germany (+3,7% compared to 2020), 465,8 TWh in France (+4,8% compared to 2020), 106,6 TWh in the Netherlands (-1,4%) and 62,7 TWh in Austria (2,7%).

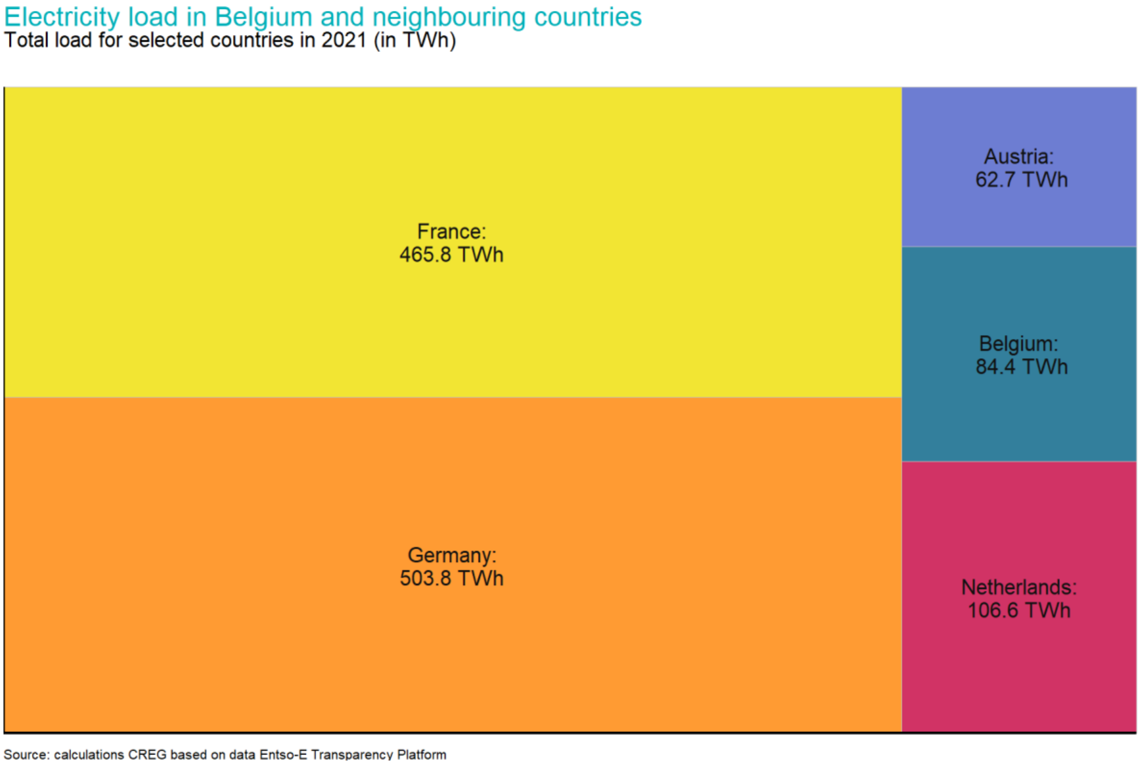
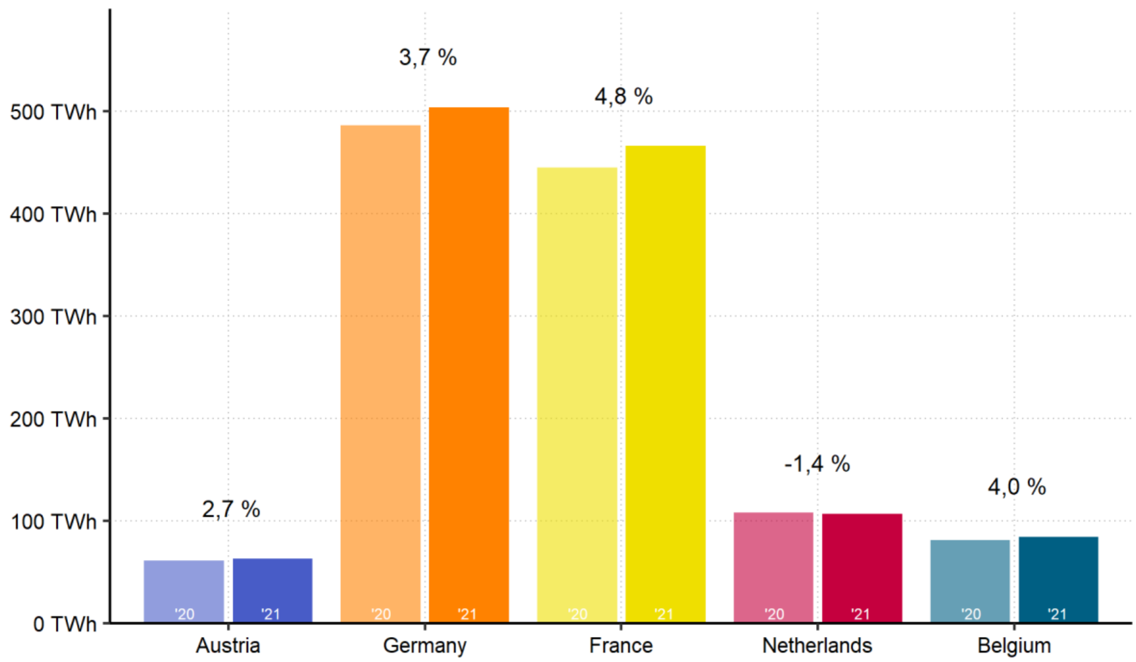


Figure 1-3 Electricity load in Belgium and neighboring countries

7. Selected European countries were impacted differently by the Covid-19 crisis. While Germany experienced a smaller reduction in its total load than any other selected country in 2020 (compared to 2019), the drop in the total electricity load fluctuated between -4,5% and -5,1% for other countries.[1] Similarly, the impact of the economic recovery initiated in 2021 on the total load varies among the selected countries, as illustrated by the negative evolution in the Netherlands which is the only country registering a decrease in its total electricity load in 2021.

[1] See also Figure 3 of the Monitoring Report 2020.

Evolution of electricity load in 2021 in Belgium and neighbouring countries
Total load for selected countries in 2020 and 2021 (in TWh)



Source: calculations CREG based on data Entso-E Transparency Platform

Figure 1-4 Evolution of electricity load in 2021 in Belgium and neighboring countries

1.1.2. At the Belgian level

8. Figure 1-5 shows in detail the evolution of the electricity peak demand in Belgium over the period 2015-2021.The figure illustrates the total load at five different levels of the yearly load duration curves[2]:

- Load at hour 1 (or maximum load);
- Load at hour 100;
- Load at hour 200;
- Load at hour 400;
- Load at hour 8760 (or minimum load).

Load duration curves were plotted for each year of the selected period. Then, for each year, the load at hours 1, 100, 200, 400 and 8760 was extracted and gathered in order to obtain Figure 1-5.

9. The maximum load has been rather stable since 2015 and amounted to 13.562 MW in 2021 (+1,6% compared to 2020). Despite the Covid crisis, 2020 is not the year with the lowest peak load value (13.344 MW in 2020 while the peak load was 13.310 MW in 2018). Though, the load at hours 100, 200, 400 and 8760 was significantly lower in 2020 compared to other years, illustrating the overall low electricity demand in 2020 as a consequence of the Covid-19 crisis.

[2] In a load duration curve, the levels of electricity load are sorted from high (hour 1) to low (hour 8760).

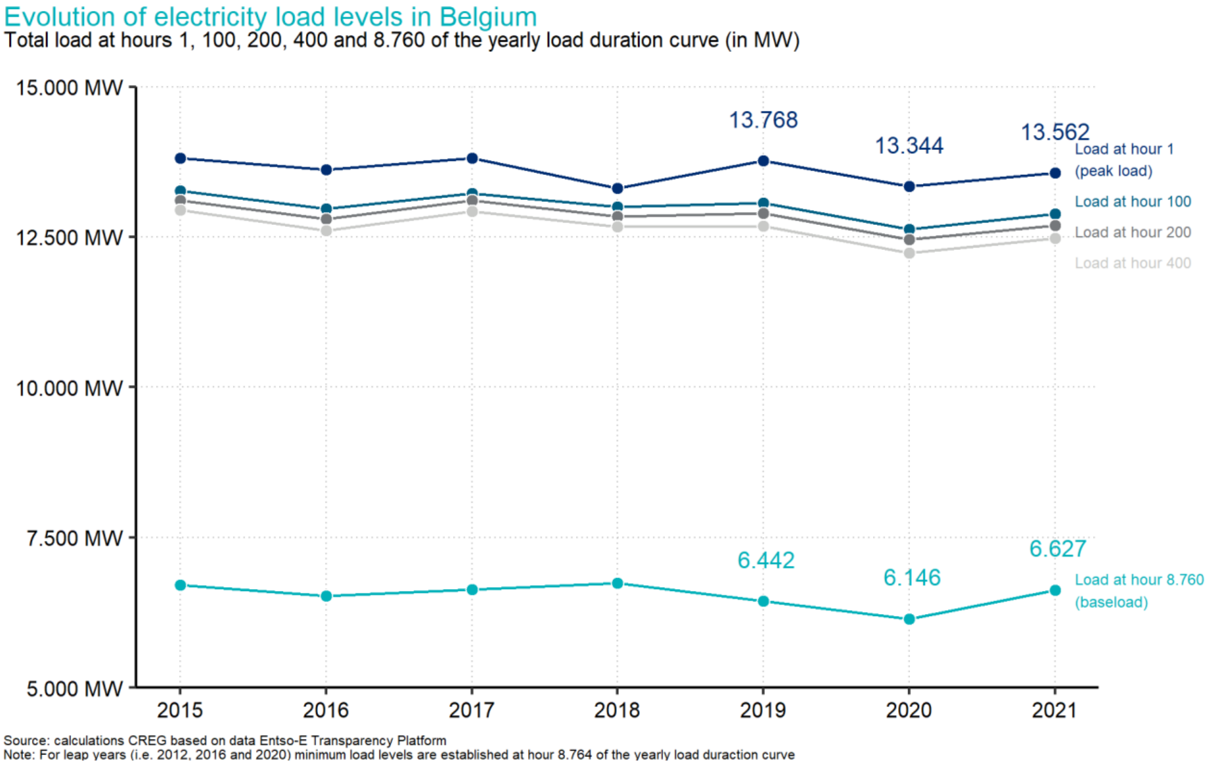


Figure 1-5 Evolution of electricity load levels in Belgium

1.2. TEMPERATURE SENSITIVITY OF ELECTRICITY CONSUMPTION

10. Figure 1-6 illustrates the monthly average total Belgian load for the period 2015-2021 (be aware that the ordinate axis starts at 7.000 MW). The shape of the curves shows the temperature sensitivity of electricity consumption: in winter, the average total load is significantly higher than during the summer months (up to a 2.000 MW difference).

11. This figure also illustrates that Belgium's total electricity load in 2021 returned to levels similar to the 2015-2019 period. This increase in total load was mainly driven by the economic rebound following the Covid-19 crisis as well as a yearly average temperature significantly lower in 2021 (10,7°C) than in 2020 (12,2°C, warmest year on record).

12. The Covid-19 impact on the Belgian total load is also quite visible. While the first two months of 2020 were rather warm (thus explaining an already low electricity load compared to other years), electricity consumption dropped in March when the confinement measures entered into force. Though, winter 2020 is amongst the three warmest winters since 1900, also explaining the significant drop in the total electricity load at the beginning of the confinement measures (2020 is actually the warmest year on record). In April 2020, the monthly average total load reached its minimum value (8.210 MW) before rising from May as measures were progressively lifted.

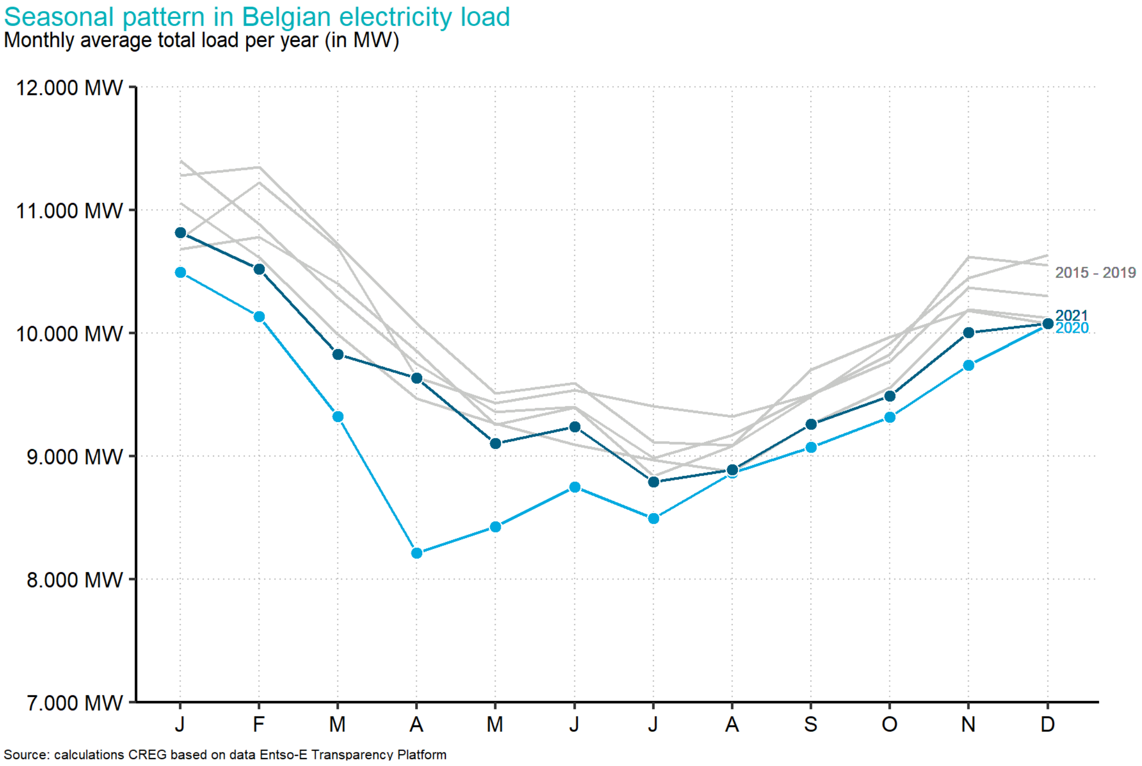


Figure 1-6 Seasonal pattern in Belgian electricity load

13. Figure 1-7 illustrates more precisely the thermosensitivity of electricity consumption in Belgium. Each dot represents a given day. As temperature decreases, one can clearly see that the average total load increases. This is mainly due to electric heaters being turned on to warm buildings. On the other hand, electricity consumption also rises when temperatures reach a certain (positive) level. This can be explained by the use of air conditioning to cool down interiors during summer months.

14. The differences in the relationship between 2020 and 2021 can be explained by the differences in yearly average temperature. As highlighted before, 2020 is the warmest year on record. This can be clearly seen on Figure 1-7 as the trend line for 2020 shows an upward trend at the right side of the figure, indicating an increase in temperatures and consequently, increase in load levels.

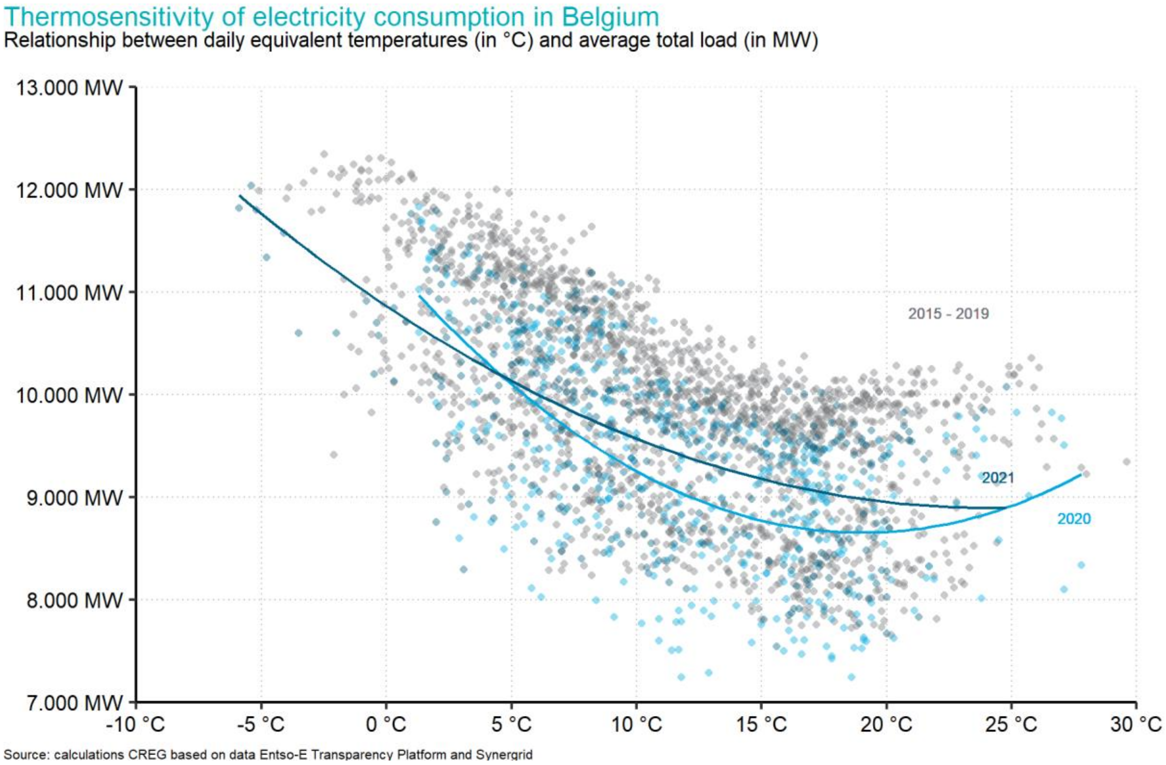


Figure 1-7 Thermosensitivity of electricity consumption in Belgium

1.3. INDUSTRY AND HOUSEHOLD CONSUMPTION

15. Figure 1-8 illustrates the evolution of electricity consumption at transmission and distribution levels in Belgium over the period 2015 – 2021. Households and small industries are connected at the distribution level of the Belgian grid while most industries in Belgium are connected at the transmission level.

16. Over the period 2015 – 2021, the electricity consumption of end-consumers connected to the transmission and distribution networks of the Belgian grid remained stable around 80 TWh before decreasing in 2019. This decreasing trend continued in 2020 (75,1 TWh) because of the COVID-19 pandemic which significantly reduced electricity consumption both at the transmission and distribution levels. In 2021, electricity consumption at the transmission and distribution levels increased to 78,3 TWh, reaching back the 2019 level. This represents a 4,9% increase (vs. 2020) at the transmission level and an increase of 3,9% (vs. 2020) at the distribution level.

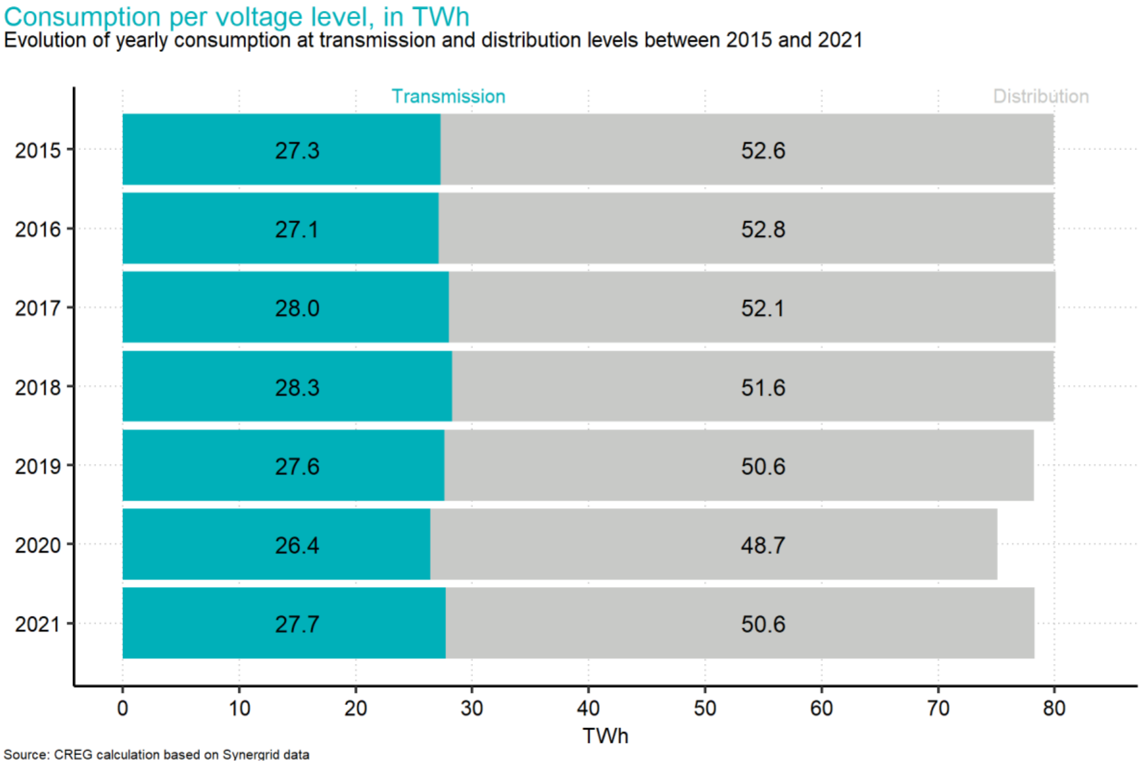


Figure 1-8 Consumption per voltage level

17. Figure 1-9 shows the evolution of electricity consumption at the distribution level in the three Belgian regions between 2015 and 2021. Flanders is the region with the largest population where most (small and large) industries are located. Hence, electricity consumption at distribution level is significantly larger in Flanders than in Wallonia and Brussels.

18. In the three regions, electricity consumption stagnated over the considered period, with the exception of 2020 because of the COVID-19 crisis. Brussels' area was the most impacted region in terms of reduction in electricity consumption (-14,4% in 2020 compared to 2019). In 2021, consumption increased in the three regions to reach back the 2019 level.

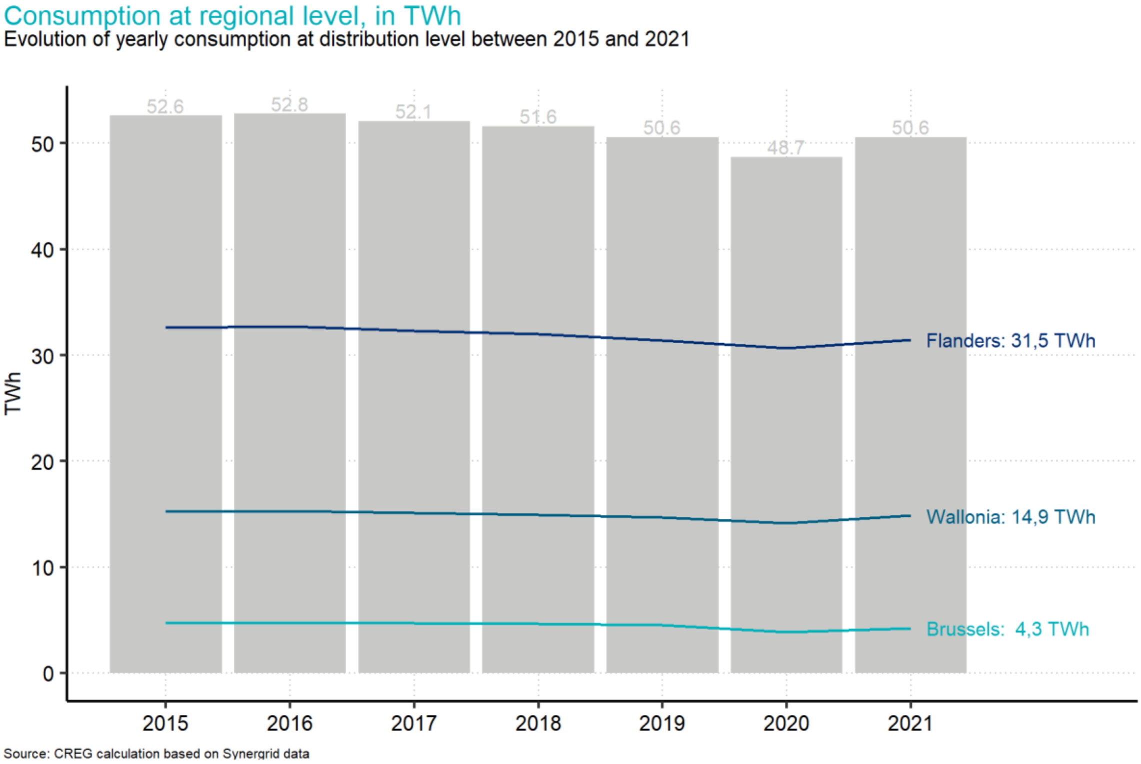


Figure 1-9 Consumption at regional level

2. PRODUCTION

2.1. INSTALLED CAPACITY

19. At the end of 2021, the total installed generation capacity[3] in Belgium amounted to 25,7 GW, compared to 24 GW in 2020. The installed generation capacity continuously increased over the 2015-2021 period (+ 5,6 GW). This significant increase is mainly due to the development of renewable energy sources (solar and wind). In particular, wind installed capacity increased by a factor of 2,5 between 2015 and 2021 while solar installed capacity increased by a factor of 1,7 over the same period. The nuclear and hydropower installed capacities remained more stable over the past 6 years. On the other hand, installed capacity of fossil plants slightly increased by 975 MW.

20. 2021 was a record year with 1,7 GW installed in total : + 900 MW in solar installed capacity, +213 MW for wind and +500 MW for fossils[4] (net numbers).

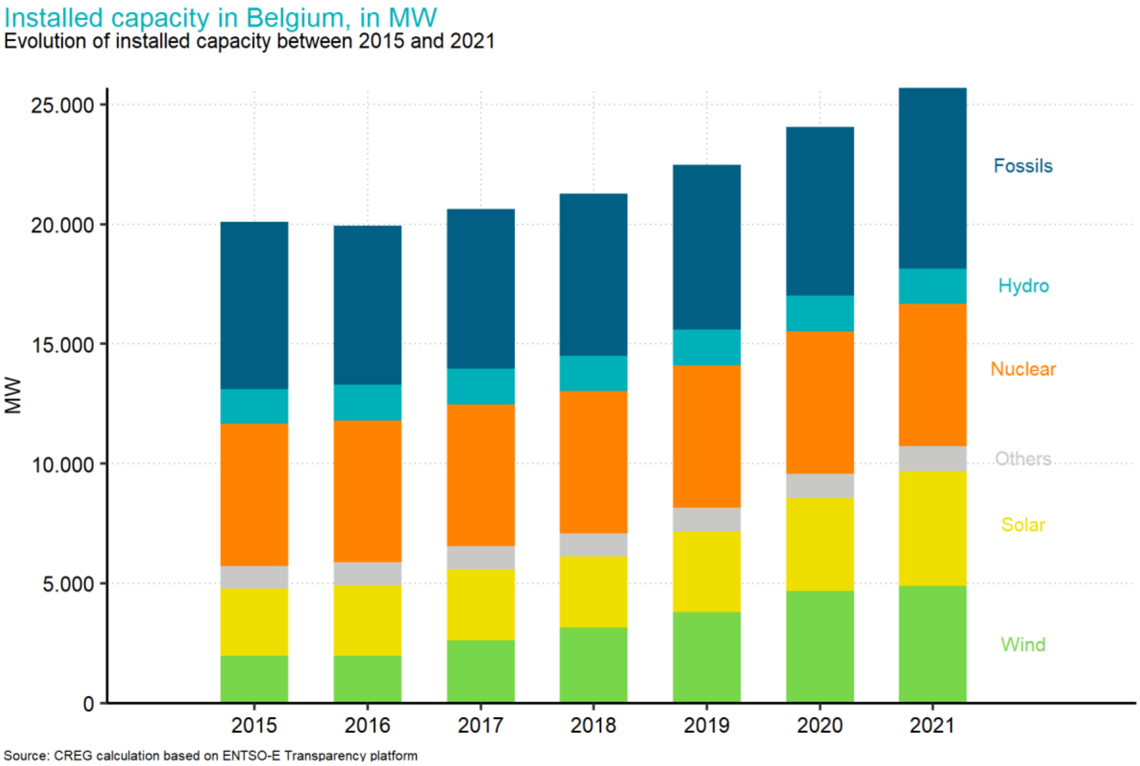


Figure 2-1 Installed capacity in Belgium, in MW

[3] The total installed generation capacity refers here to the installed net generation capacity (for all existing production units equalling or exceeding 1 MW) which is effectively installed on January 1st of the following year.
[4] Fossil gas and fossil oil.

21. Wind is the technology with the largest increase in installed capacity between 2015 and 2021, mainly driven by offshore wind capacities. Installation of solar panels has also been quite significant since 2018 (+1,3 GW between 2018 and 2021), with additional 420 MW installed in 2019, 520 MW in 2020 and an extra 900 MW installed in 2021 alone.

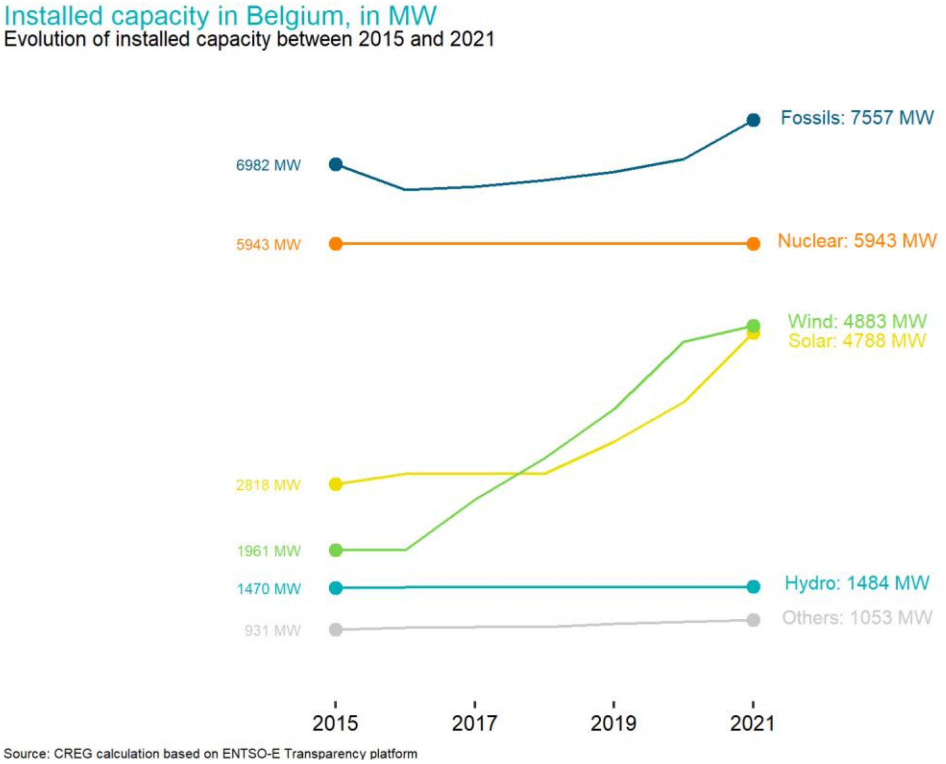


Figure 2-2 Installed capacity in Belgium, in MW

2.2. AVAILABILITY OF GENERATION ASSETS

22. Figure 12 illustrates the full availability rate of generation units by fuel type in 2021. The full availability rate is defined as the number of days of full availability throughout the year, or in other words, the number of days in which no outages occurred (forced and planned outages are considered here). Each small dot represents a generation unit, while the bigger dots represent the average full availability rate by fuel type.

23. In 2021, generation units were highly available throughout the year. Only two units were fully available for less than 50% of the time: Vilvoorde power plant (22%), which was only available for a few hours each working day from January to July 2021 and then had to shut down for revision from mid-July to end of September, and Marcinelle power plant (32%) which was unavailable for overhaul from July to October 2021.

24. As far as nuclear units are concerned, their average availability rate considerably improved in 2021 compared to last year when it reached only 46%. All nuclear reactors were fully available for more than 80% of the time in 2021, while Tihange 1 and Tihange 2 were fully available almost 100% of the time.

25. The availability rate of individual units or per fuel type do not necessarily reflect the utilisation rate. The latter is further explored in section 2.4, where the generated energy is compared to the installed capacity (i.e. the so-called capacity factor). It is possible that, while a unit is available in 100% of the time (as no outages occur), its actual output is well below the theoretically possible output (which corresponds to the full capacity multiplied by the time period).

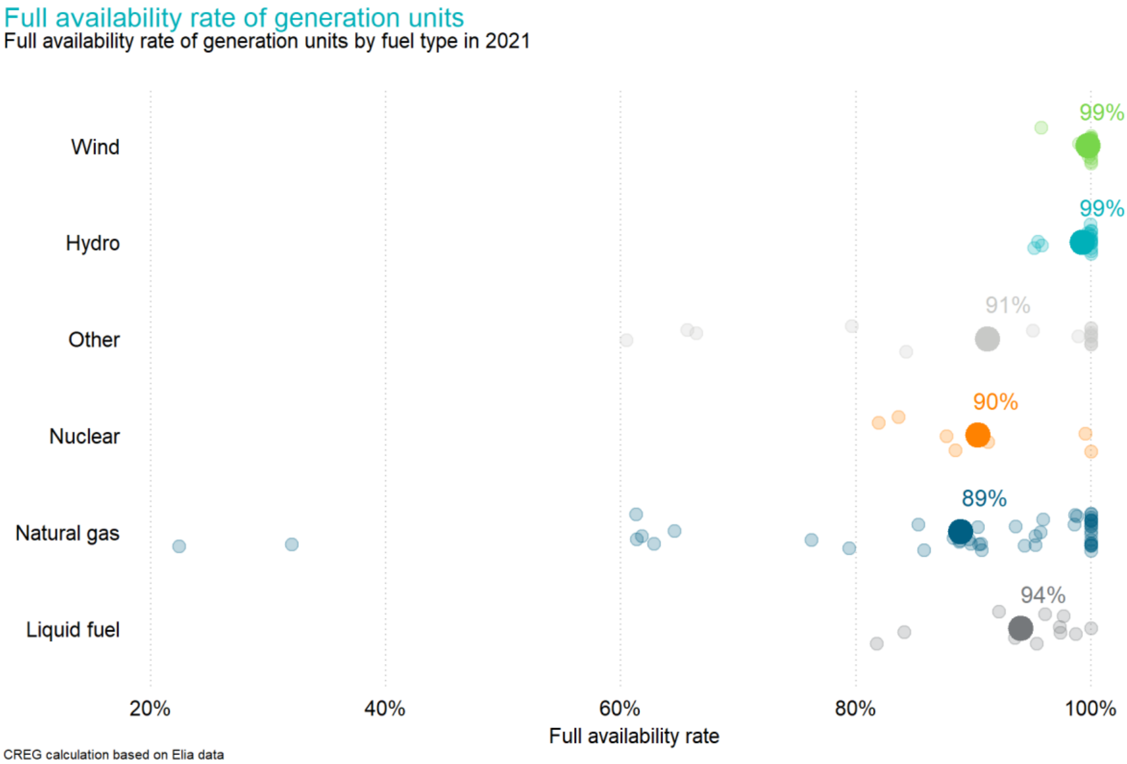


Figure 2-3 Full availability rate of generation units

2.3. GENERATED ENERGY

26. Belgian power plants generated a record amount of electricity in 2021: 93,3 TWh were produced in the Belgian control area, as shown in Figure 2-4. Thanks to the continuous high availability of the nuclear generation fleet, 48,0 TWh of electricity were produced by the 7 reactors in Doel and Tihange. At the same time, the production of electricity from gas-fired power plants decreased to 19,1 TWh. The evolution of the annual volumes of electricity produced per generation technology between 2020 and 2021 is shown in Figure 2-5.[5]

27. The strong increase in electricity generation, combined with the relative decrease in electricity demand (see previous chapter), resulted in high electricity exports to neighboring countries, especially Great Britain and France (see also chapter 3).

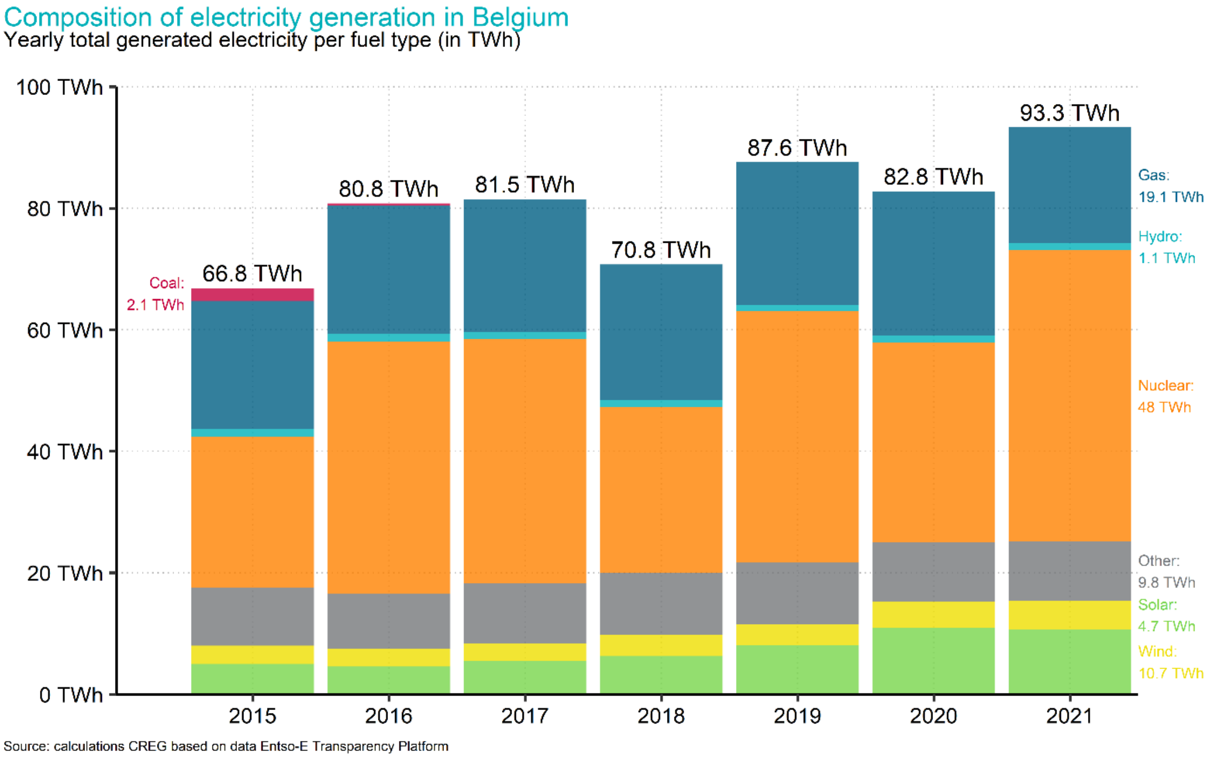


Figure 2-4 Composition of electricity generation in Belgium

28. Figure 2-5 shows the annual fluctuations in generation by technology. To visualize the evolution by generation technology in 2021 compared to the previous year, this figure illustrates, step by step, how the total generation of 82,8 TWh in 2020 evolves toward a generation of 93,3 TWh in 2021.

29. The main driver for the increase in generation is the rise in nuclear generation: it increased by 15,2 TWh (to 48 TWh) on an annual basis. In contrast, gas-fired generation fell sharply by 4,7 TWh (to 19,1 TWh). Wind (-0,24 TWh to 10,7 TWh) and solar (+0,42 TWh to reach 4,7 TWh) generation remained more or less stable, despite the increase in installed capacity (see Figure 2-1). This was due

[5] Data on electricity generation is based on data from the Entso-E Transparency Platform ("ETP", datasets 16.1.B_C) and are therefore not based on the measured and reported CIPU injections of Elia. The ETP data encompass measurements of all production units. Where these measurements are not available (for example for smaller production units, without CIPU contracts), estimations are used. For example, smaller cogeneration units (which, according to ETP, are included in the "gas" category") usually do not have a CIPU contract, and are hence excluded from the Elia data – leading to significant differences for this category between the two sources. This remark also applies to the section 2.1 where installed capacities from the ETP are shown.

to relatively unfavorable weather conditions which had a negative impact on the load factor of these technologies.

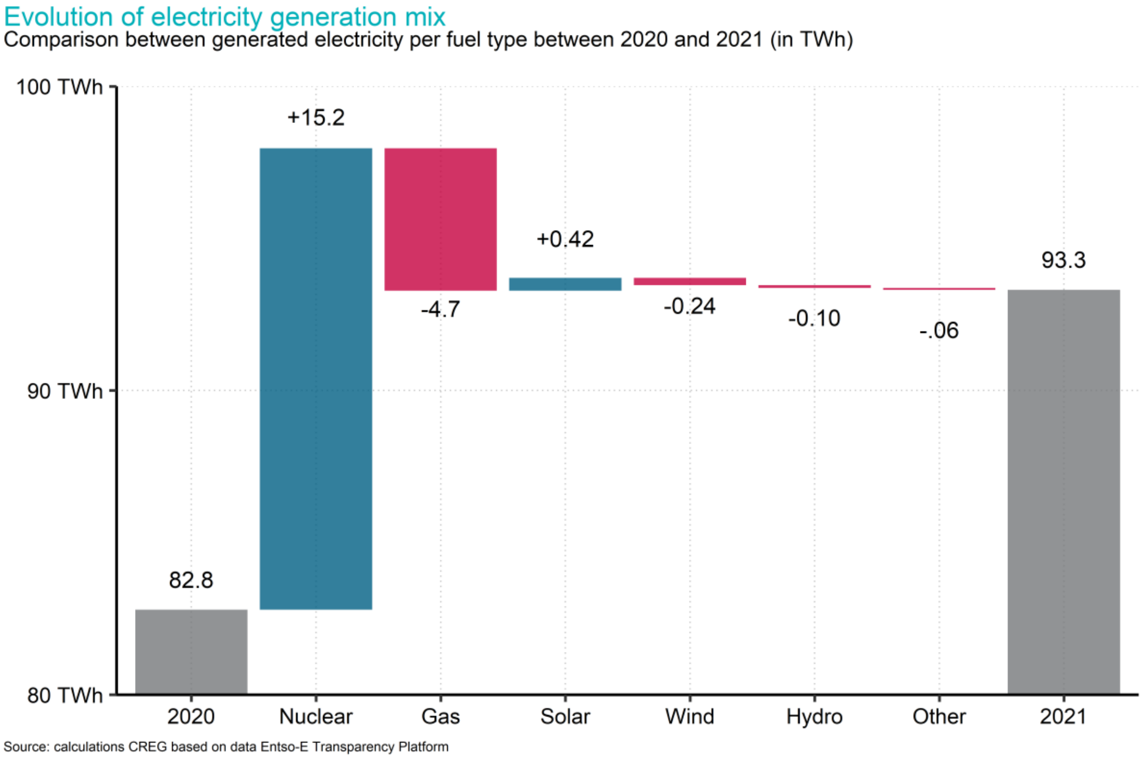


Figure 2-5 Evolution of electricity generation mix

30. Figure 2-6 illustrates the evolution of monthly average electricity generation in Belgium between 2015 and 2021. This figure clearly shows that monthly electricity generation follows the same trend as electricity consumption: generated electricity is significantly higher in the winter months than during summer in order to accommodate higher levels of demand for electricity.

31. The Covid-19 crisis seems to have had no notable impact on electricity generation in Belgium if one compares with the previous years, and in particular with 2015 and 2018 (as already highlighted in Figure 2-4). In 2021, electricity generation reached record levels with 12.050 MW generated in February 2021. Monthly average electricity generation has been higher than 11.000 MW for five months in 2021 (January, February, March, April and December). Such levels of electricity generation have only been reached once before in the previous years (it was in September 2019).

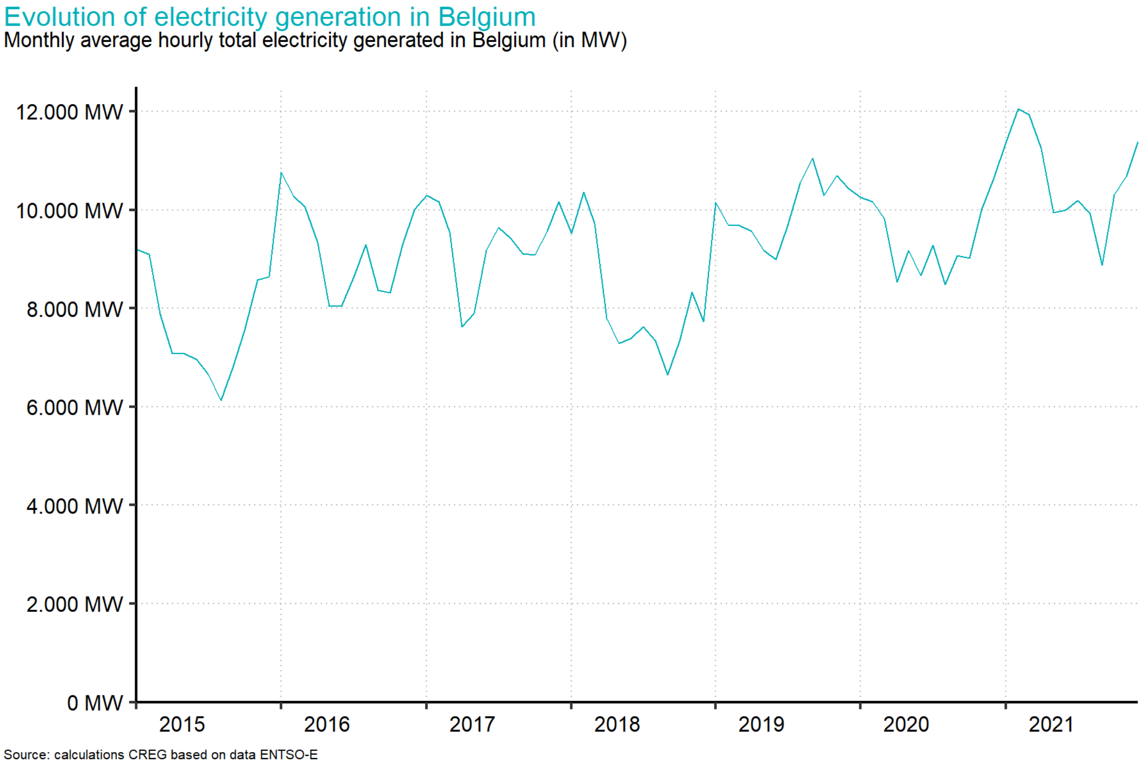


Figure 2-6 Evolution of electricity generation in Belgium

32. Figure 2-7 shows the monthly total electricity generation per fuel type in Belgium in 2021. The shape of the curve logically follows the curve representing Belgium's average monthly electricity load (Figure 1-6): in the winter months, generation units must produce more to accommodate higher levels of demand for electricity. In 2021, electricity generation was significantly higher than demand, resulting in high electricity exports to neighboring countries (see also Chapter 3).

33. Nuclear generation remained quite high throughout the year thanks to the high availability rate of the seven nuclear reactors. The unavailabilities of Doel 3 in September 2021 and of Doel 4 in November 2021 explains the relative decrease in nuclear generation. This figure also illustrates the seasonality of renewable production: solar generation increases in spring and summer while wind generation reaches higher levels during the winter months thanks to better wind conditions (see also Figure 2-8 and Figure 2-10).

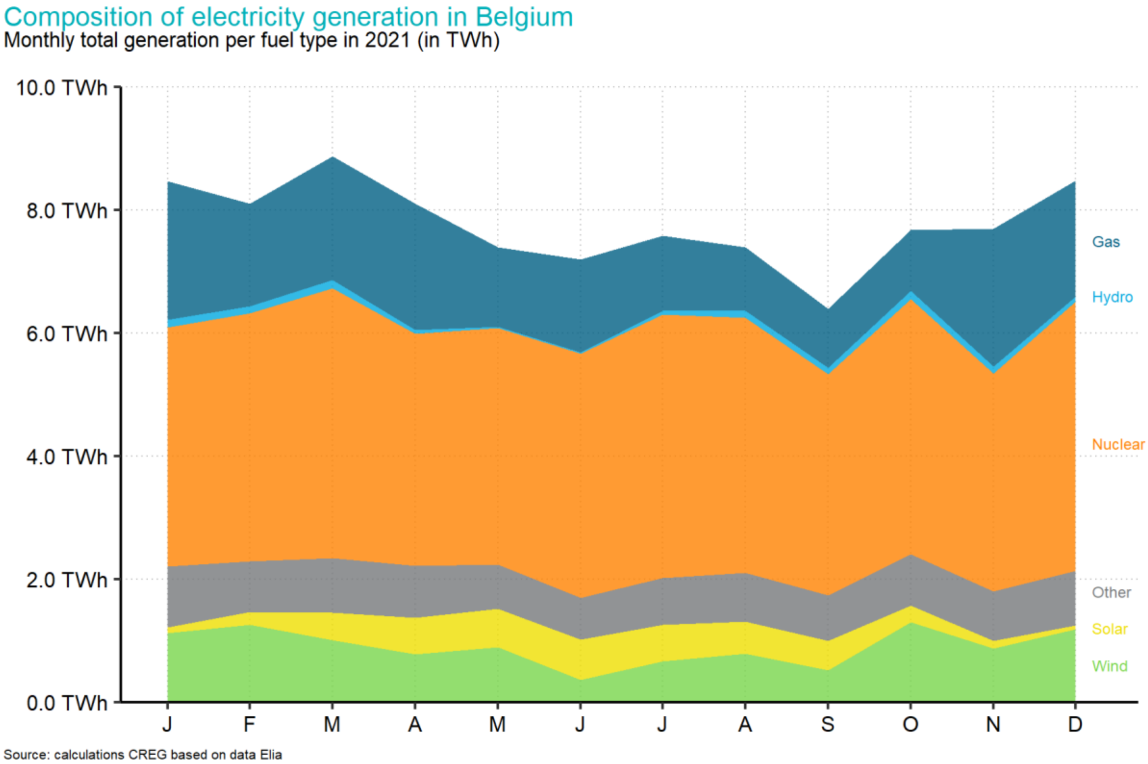


Figure 2-7 Composition of electricity generation in Belgium

34. Wind generation significantly increased between 2015 and 2021. This is mainly due to the rise in installed capacity (wind installed capacity more than doubled over that period, as illustrated in Figure 2-1 and Figure 2-2). However, wind generation depends strongly on wind conditions which, in Belgium, are more favorable during the winter months. This is clearly illustrated in Figure 2-8 which shows that wind generation is systematically higher from January to March and from October to December than during the rest of the year. Additionally, differences between 2020 and 2021 cannot only be explained by the relative small increase in wind installed capacity (+216 MW in 2021).

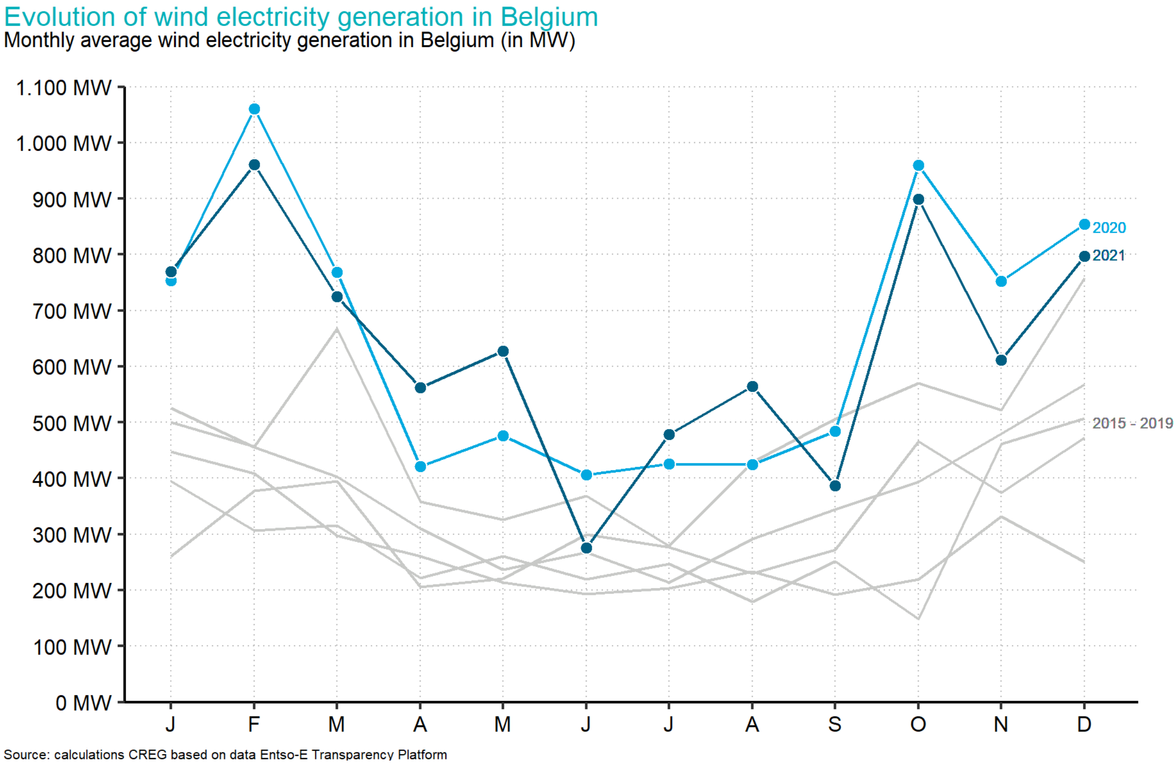


Figure 2-8 Evolution of wind electricity generation in Belgium

35. Similarly, solar electricity generation has been considerably increasing since 2015 to reach 4,7 TWh in 2021 (see Figure 2-9). The installation of solar panels throughout Belgium, in particular from 2018 (as illustrated on Figure 2-2), has been supporting this rise in solar electricity generation. Bad sunlight conditions can explain the small decrease in solar generation in 2016 and 2017 as well as the relative small increase in 2021 compared to 2020 while 900 MW of solar panels were installed in 2021. For comparison, solar generation increased by 0,7 TWh between 2019 and 2020 (while solar installed capacity rose by 520 MW) whereas it only increased by 0,4 TWh between 2020 and 2021.

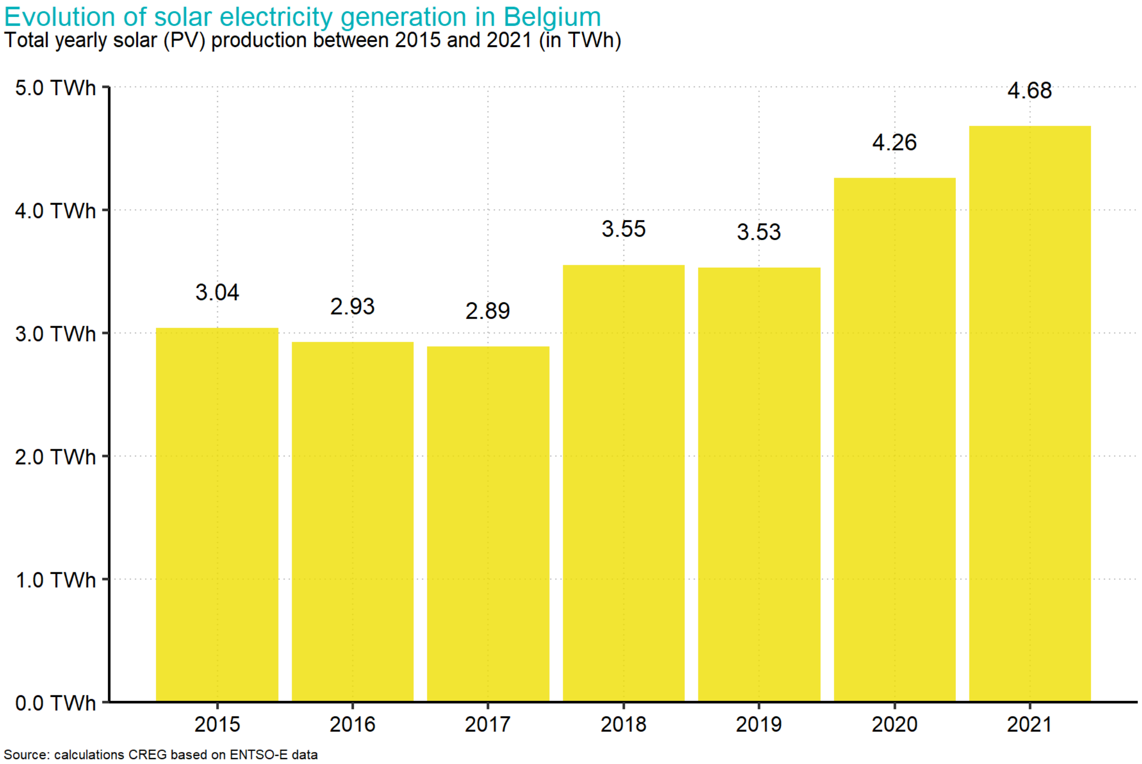


Figure 2-9 Evolution of solar electricity generation in Belgium

36. Figure 2-10 illustrates the seasonality of the wind and solar electricity generation. One interesting observation is that electricity generation from wind and solar varies in opposing but complementary manners: during winter, wind conditions are pretty good and sunlight conditions are rather bad, thus explaining high levels of wind generation and low levels of solar generation. On the other hand, wind conditions are less favorable in spring and summer while sunlight conditions considerably improve, resulting in higher levels of solar generation and lower wind generation. In short, wind generation is high when solar generation is low and vice versa.

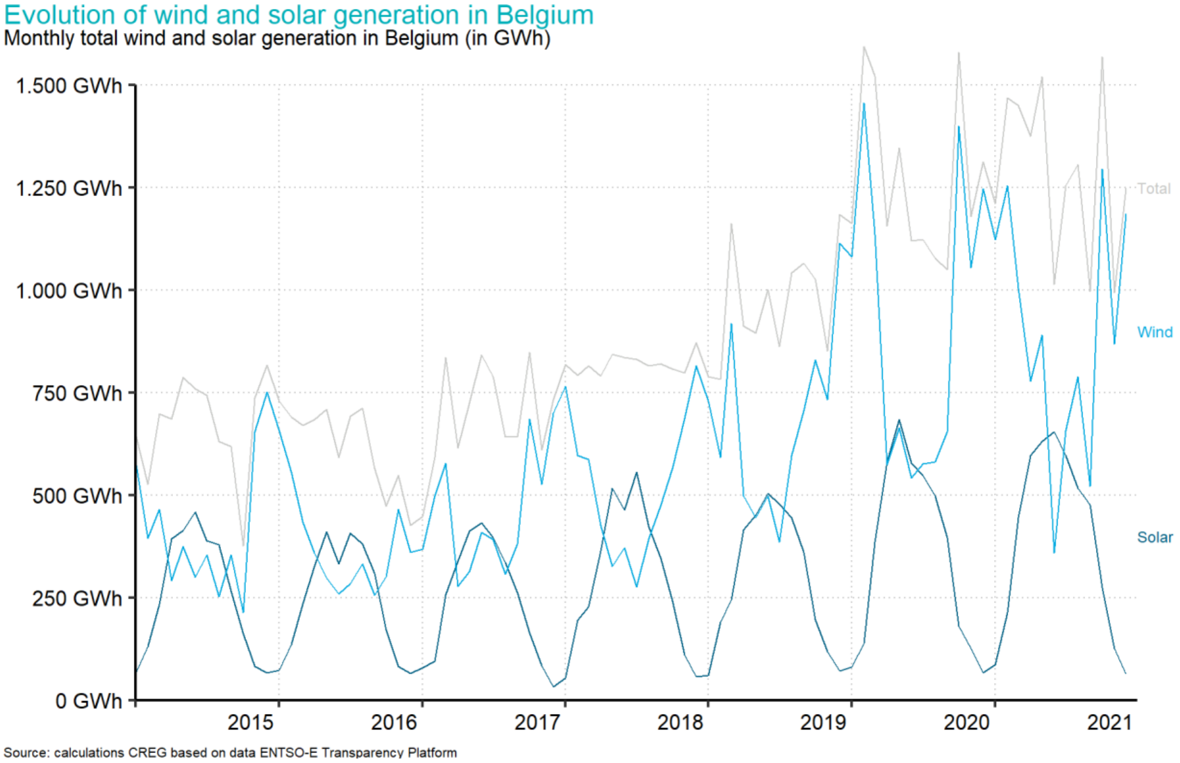


Figure 2-10 Evolution of wind and solar generation in Belgium

2.4. CAPACITY FACTOR

37. The capacity factor of production installations represents the overall utilization of those installations. In other words, it measures a power plant's actual generation compared to the maximum amount it could theoretically generate in a given period without any interruption (here, a year)[6].

38. Among intermittent renewable energy sources, offshore wind is the technology with the highest capacity factor. Wind farms located offshore benefit from better wind conditions, thus increasing their generation. As a consequence, a significant difference in capacity factor can be observed between offshore and onshore wind (34% and 17% in 2021, respectively). The yearly variations, despite a continuous increase in wind installed capacity between 2015 and 2021, reflect the intermittent nature of wind generation.

39. On the other side, solar is one of the technologies with the lowest capacity factor (11% in 2021) since solar panels can only produce electricity during daytime. The capacity factor of solar has been relatively stable over the 2015-2021 period despite a significant increase in installed capacity and electricity generation. Even though solar generation depends on sunlight conditions, only technological progress in solar panels can have a significant impact on the capacity factor.

[6] Data for installed capacity are only available in the form of annual data and refer to the installed net generation capacity which is effectively installed on January 1st of the following year. Thus, in order to reflect the increases in installed capacity during a given year, we considered the average installed capacity with the previous year. For instance, for the year 2021, we computed the 2021-2022 average installed capacity and used it as input data to calculate the capacity factor in 2021.

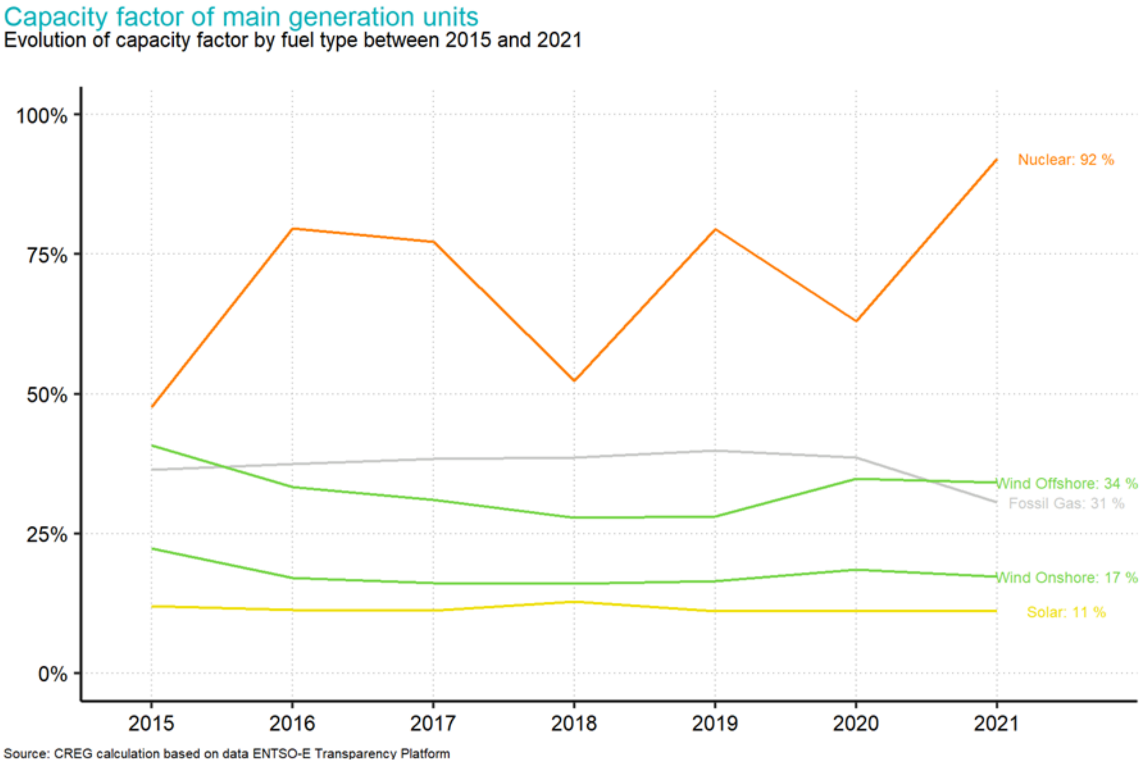


Figure 2-11 Capacity factor of main generation units

40. As far as conventional generation is concerned, nuclear is by far the technology with the highest capacity factor. Because of their limited flexibility, nuclear power plants are used for baseload generation thus generally producing on a continuous basis throughout the year. The very high availability rate of nuclear power plants in 2021 explains the significant increase in the capacity factor.

41. The capacity factor of gas-fired power plants remained stable just below 40% from 2015 to 2020 but decreased to 31% in 2021. Fossil gas generation was less needed in 2021 because of the high availability rate of nuclear power plants, which produced 51% of Belgium's total electricity generation (compared to only 39% in 2020).

2.5. CARBON INTENSITY OF ELECTRICITY GENERATION

42. Figure 2-12 illustrates the evolution of greenhouse gas emission intensity of electricity production in Belgium and neighboring countries for the period 1990 – 2020.[7,8] Greenhouse gas emission intensity of electricity production decreased significantly over that period for all selected countries. The United Kingdom is the country recording the sharpest decrease (from 681 gCO_{2eq}/kWh in 1990 to 230 gCO_{2eq}/kWh in 2019). In particular, greenhouse gas emission intensity in the UK was divided by 2 between 2012 and 2019.

43. Belgium's greenhouse gas emission intensity of electricity production decreased from 358 gCO_{2eq}/kWh to 161 gCO_{2eq}/kWh between 1990 and 2020, i.e. a reduction of 55%. The level of greenhouse gas emission intensity is highly dependent on the energy mix used to produce electricity. The downward trend over the considered period can be explained by the gradual phase-out of coal (since 2016, no more electricity is produced from coal-fired power plants in Belgium) and by the growth

[7] Data are only available until 2019 for the United Kingdom.

[8] This analysis is based on national generation mixes only; it does not reflect the carbon intensity of the import and export of electricity.

of solar and wind in the electricity production mix. Recently, surges in the greenhouse gas emission intensity of the production mix in Belgium were witnessed in 2015 and 2018, when the reduced nuclear availability and generation had to be compensated by an increase in electricity generation from fossil fuel sources.

44. France and Austria are the only countries with a greenhouse gas emission intensity below 100 gCO_{2eq}/kWh (51,1 gCO_{2eq}/kWh and 82,4 gCO_{2eq}/kWh respectively). This can be explained by their highly decarbonized electricity generation mix, mainly based on nuclear for France and hydro for Austria.

45. Despite a considerable reduction in 2020 compared to 2019, electricity production in the Netherlands and Germany remains highly carbon-intensive. In 2020, greenhouse gas emission intensity of electricity production was as high as 328,4 gCO_{2eq}/kWh (-16% compared to 2019) for the Netherlands and 311 gCO_{2eq}/kWh for Germany (- 9.6%).

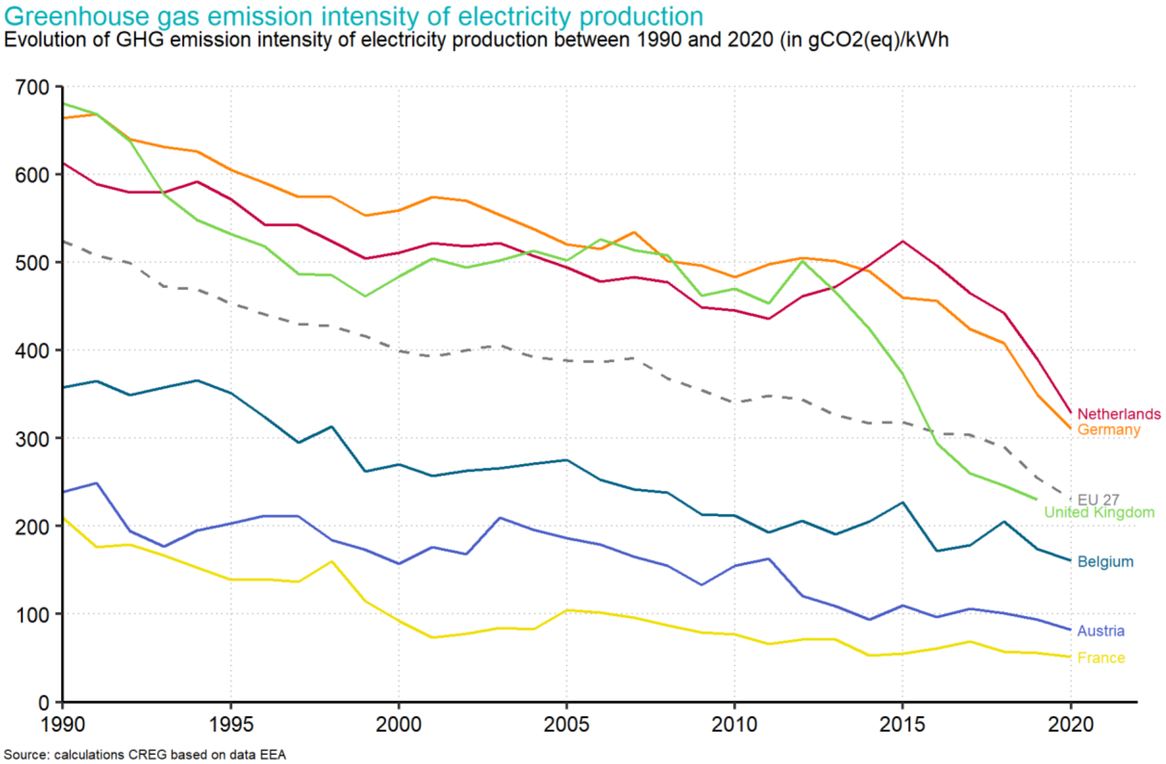


Figure 2-12 Greenhouse gas emission intensity of electricity production

3. CROSS-BORDER FLOWS

46. Belgium has physical interconnections with 5 other countries: France, the Netherlands, Luxembourg, United Kingdom and Germany. The HVDC connections with the United Kingdom (early 2019) and Germany (end of 2020) are relatively new. The flows and net positions observed on the borders of Belgium and its neighbors are the result of the import and export nominations for exchanges in the long-term, day-ahead and intraday timeframe as well as cross-border adjustments in the balancing timeframe.

3.1. FLOWS PER BORDER

47. Figure 3-1 shows the evolution, between 2015 and 2021, of the net export flows per border, taken by subtracting the import flows from the export flows.[9] During the considered period, an alternating pattern between net export to and from the Netherlands and France has been witnessed: periods of high net import from France coincided with periods of (relatively) low net import (or net export). Globally however, Belgium was a net importer between 2015 and 2018 (see also Figure 3-3). This seasonal pattern persists from 2019 to 2021, even though Belgium has become, on average, a net exporter.

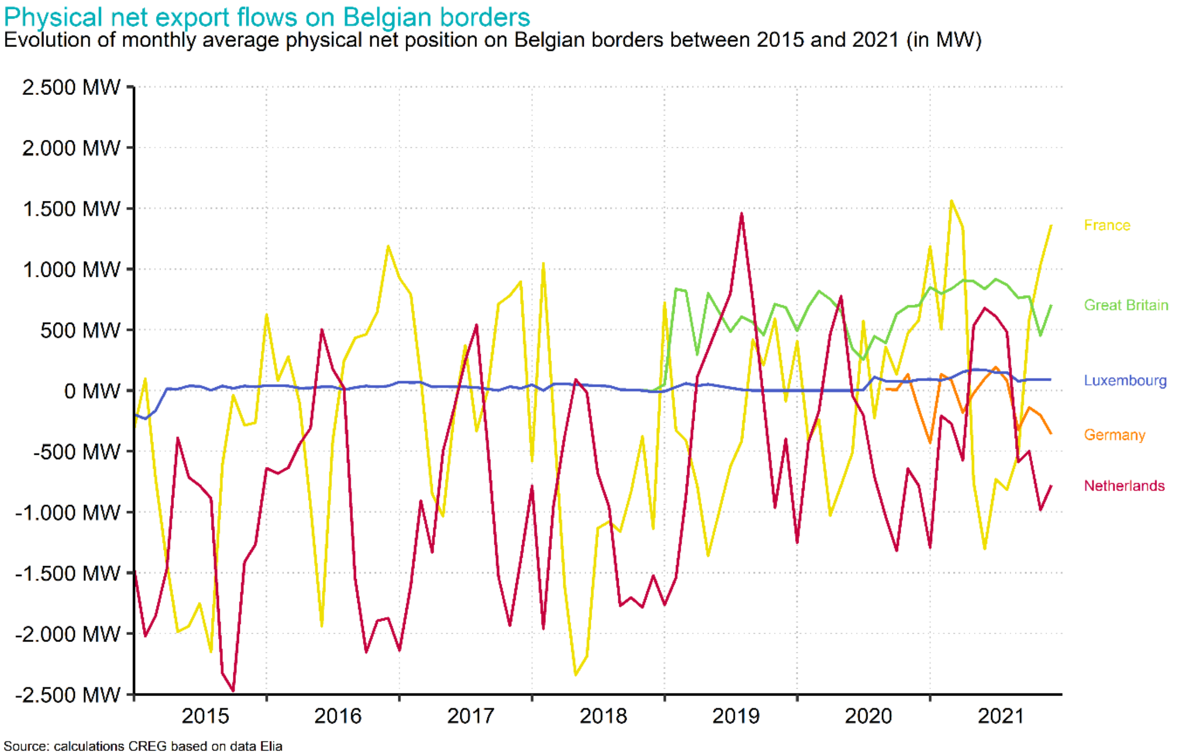


Figure 3-1 Physical net export flows on Belgian borders

[9] Hence, a net export flow begin positive indicates electricity flowing out of Belgium, and vice versa for a negative net export flow (electricity flowing into Belgium)

48. Since its operational go-live in January 2019, the Nemo Link interconnector has mainly served to export electricity from Belgium to the United Kingdom: the monthly average net export values fluctuate between 500 and 1000 MW. The ALEGrO interconnector with Germany is sometimes used for net export, sometimes for net import, depending on the market circumstances.

49. Figure 3-2 demonstrates this for 2021: while the total export flows reached 20,1 TWh, import flows reached only 12,5 TWh leading to a net export position of 7,6 TWh. These flows are distributed, however, in an uneven manner when considering the different neighbouring countries: most of the export flows go to the bidding zones France and Great Britain. For Germany, the net position was more or less balanced and from the Netherlands, more electricity is imported than exported.

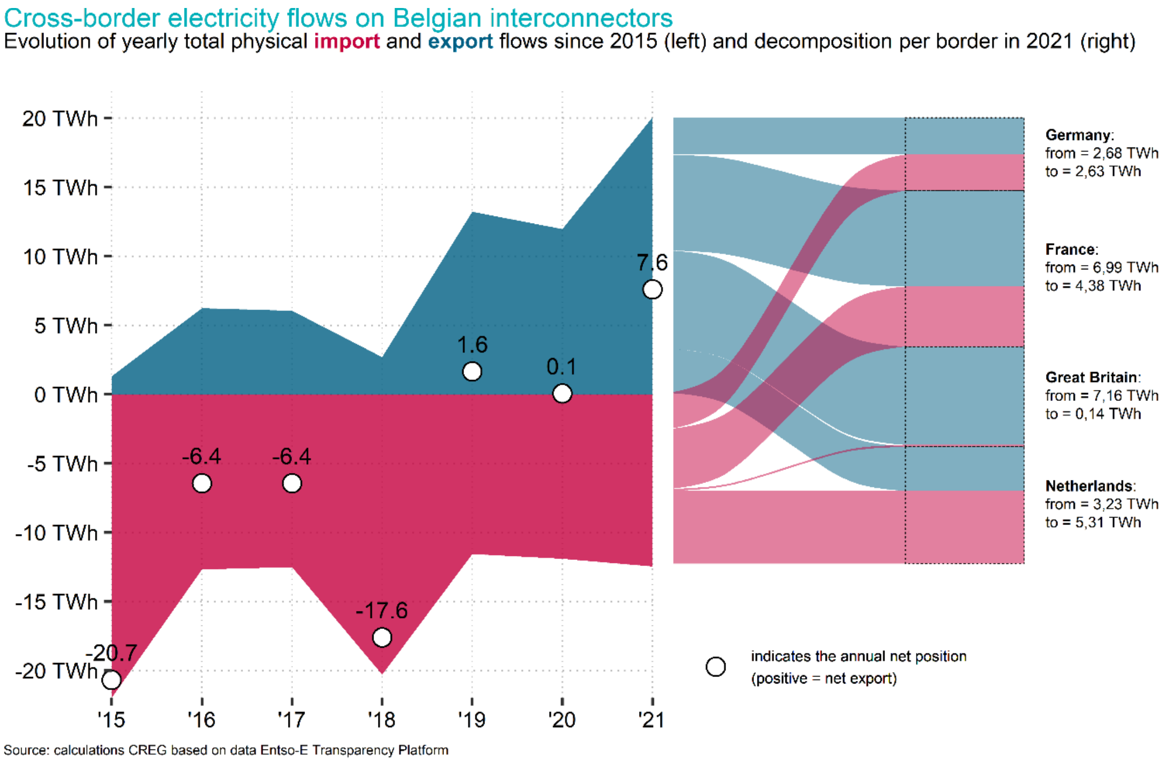


Figure 3-2 Cross-border electricity flow son Belgian interconnectors

3.2. TOTAL NET POSITION

50. The sum of the net export positions on all of Belgium's interconnectors combined is reflected in the total net position. Its evolution is shown in Figure 3-3 and the annual net positions per border are listed in Table 3-1. The shaded area in the line graph shows the monthly maximum and minimum net positions across all borders. After many years of being a physical net importer of electricity, the net export of Belgium became positive from 2019 onwards. This evolution should be seen in combination with:

- the entry into operation of the Nemo Link interconnector, adding 4 – 7 TWh of electricity exports on a yearly basis (see Table 3-1);
- the decrease of the electricity load (consumption) in Belgium; and
- an increase in electricity generation since 2018, as shown in section 2.3. In particular, the high availability of Belgium's nuclear production park in 2021 had a positive impact on its net export position.

51. In 2021, the net export position of Belgium reached an absolute record of +7,6 TWh. This value stands in stark contrast against the very large net imported volumes in 2015 and 2018. The difference between the highest and lowest yearly net position between 2015 and 2021 equals 28,6 TWh, which is about one third of Belgium's electricity consumption.

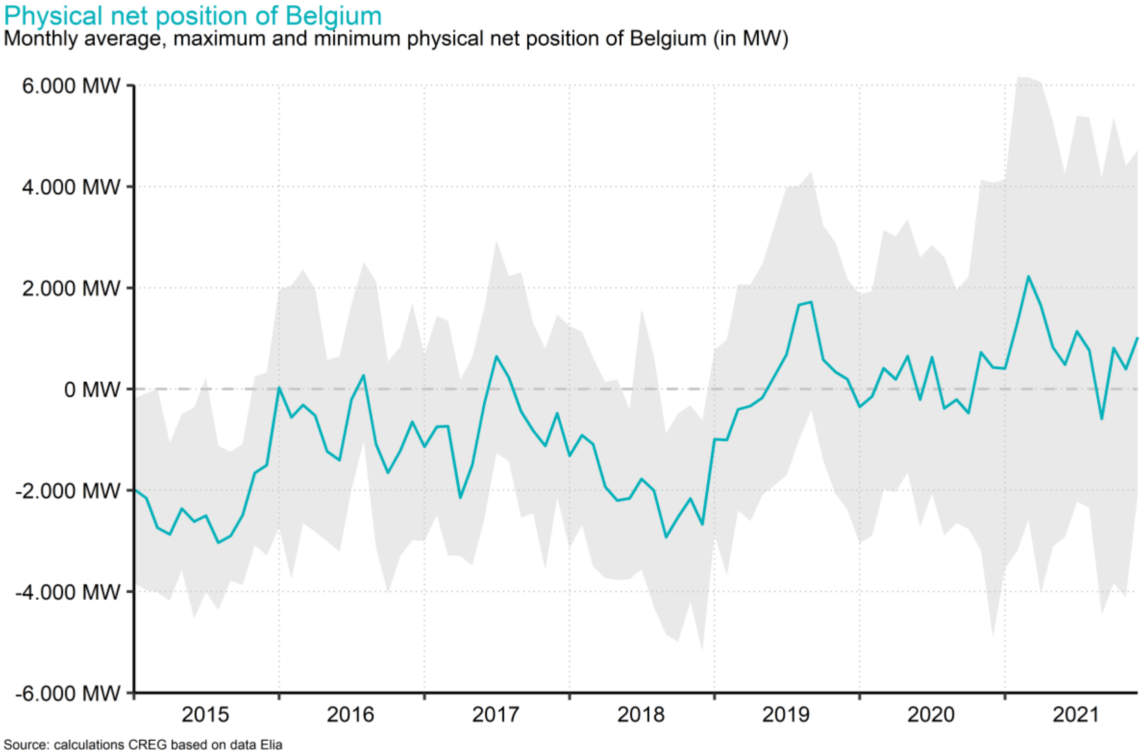


Figure 3-3 Physical net position of Belgium

(in TWh)	France	Netherlands	Luxembourg	Great Britain	Germany	**TOTAL**
2015	-8,4	-12,4	-0,3	0,0	0,0	**-21,0**
2016	0,4	-6,9	0,3	0,0	0,0	**-6,2**
2017	1,6	-8,1	0,3	0,0	0,0	**-6,2**
2018	-8,6	-9,0	0,2	0,0	0,0	**-17,3**
2019	-1,5	-1,5	0,1	4,6	0,0	**1,7**
2020	-0,5	-3,9	0,3	5,0	0,0	**0,9**
2021	2,4	-2,1	1,0	7,0	-0,8	**7,6**

Table 3-1 Evolution of total yearly imported (-) or exported (+) electricity from and to Belgium

3.3. PHSYICAL INTERCONNECTION CAPACITY

52. These physical flows of electricity are accommodated by the transmission capacity on the borders with neighboring countries. Table 3-2 provides an overview, per border, of the network elements and their physical capacity. Taken together, the network elements comprise of 13.489 MW of installed capacity for transporting electricity to and from other countries.

	kV	Substation 1	Substation 2	P_{max}
Netherlands	380	Van Eyck	Maasbracht	1.439 MW
	380	Van Eyck	Maasbracht	1.316 MW
	380	Zandvliet	Rilland	1.465 MW
	380	Zandvliet	Rilland	1.645 MW
France	380	Achène	Lonny	1.316 MW
	380	Avelgem	Mastaing	1.316 MW
	380	Avelgem	Avelin	1.528 MW
	220	Aubange	Moulaine	442 MW
	220	Abaunge	Mont St. Martin	442 MW
	220	Monceau	Chooz	400 MW
TOTAL AC				**11.489 MW**
Germany (ALEGrO)	380	Lixhe	Oberzier	1.000 MW
United Kingdom (Nemo Link)	400	Gezelle	Richborough	1.000 MW
TOTAL DC				**2.000 MW**

Table 3-2 Installed transmission capacity connecting to neighboring countries

[10] The Pmax may depend from hour to hour based on the meteorological conditions.

4. LONG-TERM MARKETS

53. Trading of electricity in Belgium may take place in long-term markets. There are standardized long-term futures markets (organized by power exchanges) and unstandardized forward markets (*"over-the-counter"* or OTC). Market players generally participate in these markets to hedge against (differences between) short-term electricity prices.

54. In this chapter, the yearly and monthly futures markets will be described. Some of these markets are purely national (for delivery in Belgium) while others are cross-zonal (for exchanging energy with coupled neighboring countries, such as France, the Netherlands, Germany and Great Britain).

4.1. FUTURES MARKETS FOR DELIVERY IN BELGIUM

55. Trading in power derivatives, such as long-term futures contracts, can take place with physical delivery of the traded electricity or as a purely financial hedge without physical delivery. The former is traded on the power exchange ICE Endex, while the latter can be traded on the power exchange EEX. Both for financial as well as physical settlements, a multitude of delivery periods are offered: one to several months ahead, one to several quarters ahead and one to several years ahead.

4.1.1. Prices

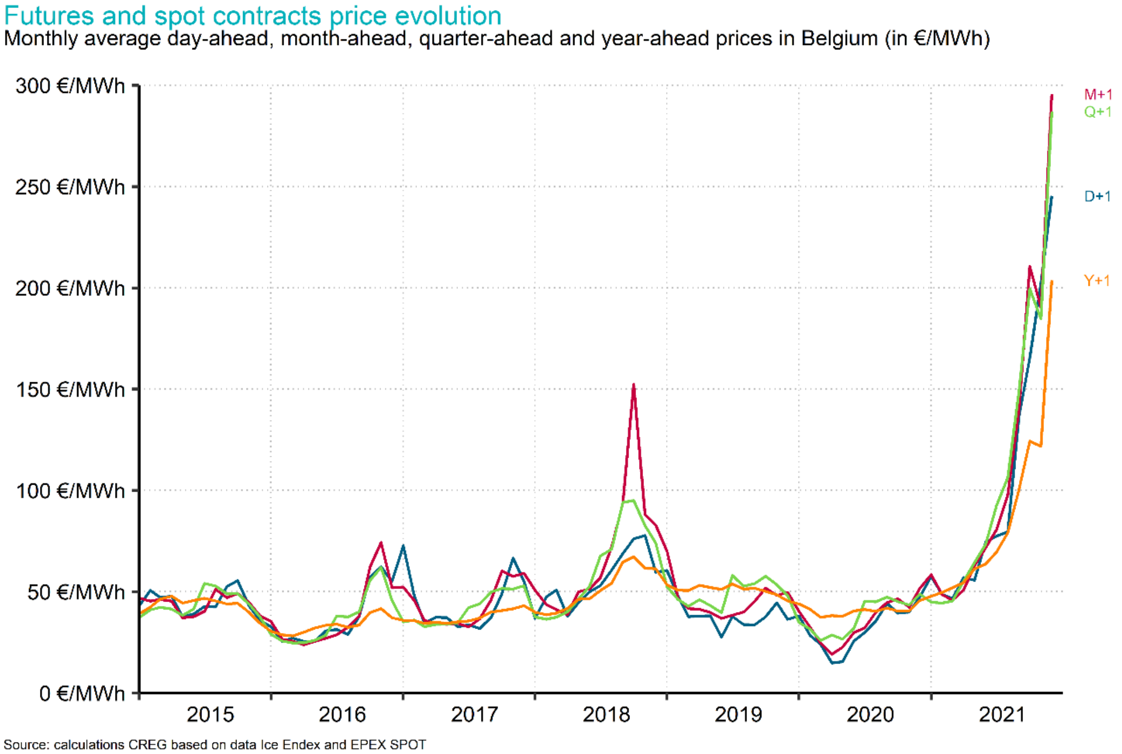


Figure 4-1 Futures and spot contracts price evolution

56. The evolution of the monthly average prices different futures contracts (on month-ahead, one quarter-ahead and one year-ahead) and the day-ahead spot contracts is shown in Figure 4-1. When the price for a futures contract (for example Y+1) is higher than the day-ahead price on contract date, it implies that on average, market participants anticipate that prices will increase for the relevant delivery period (in this case, the entire subsequent year). As an example, the observed prices at the

end of 2021 suggest that market participants consider that prices for delivery in January and the first quarter (listed via the M+1 and Q+1 products: 295,7 €/MWh and 287,2 €/MWh respectively) would, on average, be higher than the spot price during that month (245,4 €/MWh. Similarly, the price for delivery in the entire year 2022 was lower (203,8 €/MWh), indicating that the average price level for 2022 is expected to be lower than the December 2021 day-ahead price.

57. Even though the prices for futures and spot contracts, as listed on the contract data, show similar movements, it makes more sense to compare the prices at the same delivery period. This comparison shows the relative cost (or revenue, depending on the market participant) for buying (selling) electricity via spot markets or futures markets. This is shown in the Figure 4-2 below, where the different available contracts are matched and compared on the delivery date.

58. From this figure, it can be clearly observed that, depending on the purchasing / selling strategy of a market participant (i.e. either primarily in the spot market, or through futures contracts), the cost for buying electricity or revenue from selling may differ significantly.[11] In particular, for the delivery year 2021, purchasing electricity was much less expensive if done through futures contracts (any type) than on the spot market, shown by the blue bars in the below figure. The more electricity has been sold in advance, i.e. through (multi-)year-ahead contracts, the more profitable for a buyer if compared against buying the same volume in the day-ahead markets. The inverse reasoning goes for sellers: these earned a higher revenue in 2021 by selling their electricity in the day-ahead market.

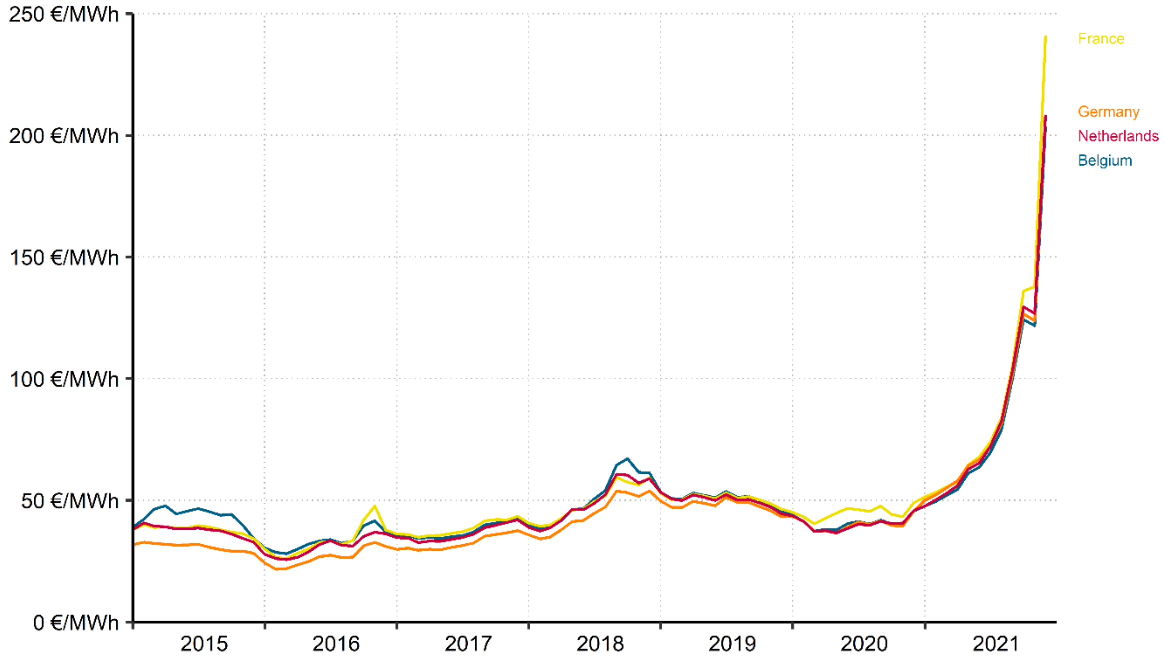
Figure 4-2 Price differentials between futures and spot contracts

[11] In the figure above, price differences between the relevant futures contract and the day-ahead contract per delivery year are shown. Red bars indicate that the price differential is positive, hence the average of all trades for a specific futures contract for a certain delivery year is higher than the corresponding average day-ahead prices, for the same delivery year.

59. Finally, it is worth noting that the year-ahead prices (just as day-ahead prices, see also chapter 5), are on average quite closely aligned among different countries. An important exception is the price spread on the one year-ahead contracts with France since the end of 2021. This reflects the tense situation in the French market where the low availability of nuclear units in the winter 2021 – 2022 and throughout the remainder of 2022 leads to higher prices for electricity.

One year-ahead contracts price evolution

Monthly average one year ahead futures prices (in €/MWh) in Belgium and neighboring countries



Source: calculations CREG based on data Ice Endex

Figure 4-3 One year-ahead contracts price evolution

4.1.2. Volumes

60. Figure 4-4 summarizes the volumes of electricity bought / sold, summarized as averages per month (on delivery date, not on contract date). In 2021, on average between 1.000 and 1.500 MWh/h was delivered through the yearly, quarterly and monthly products). Especially towards the end of the year, higher volumes were traded (through quarterly and monthly products), probably as parties were anticipating even higher prices in the day-ahead timeframe that were not (yet) reflected in the futures' prices.

61. The exchanged volumes through these contracts are in line with historical observations, with the exception of 2019, where high volumes of one year-ahead contracts were delivered.

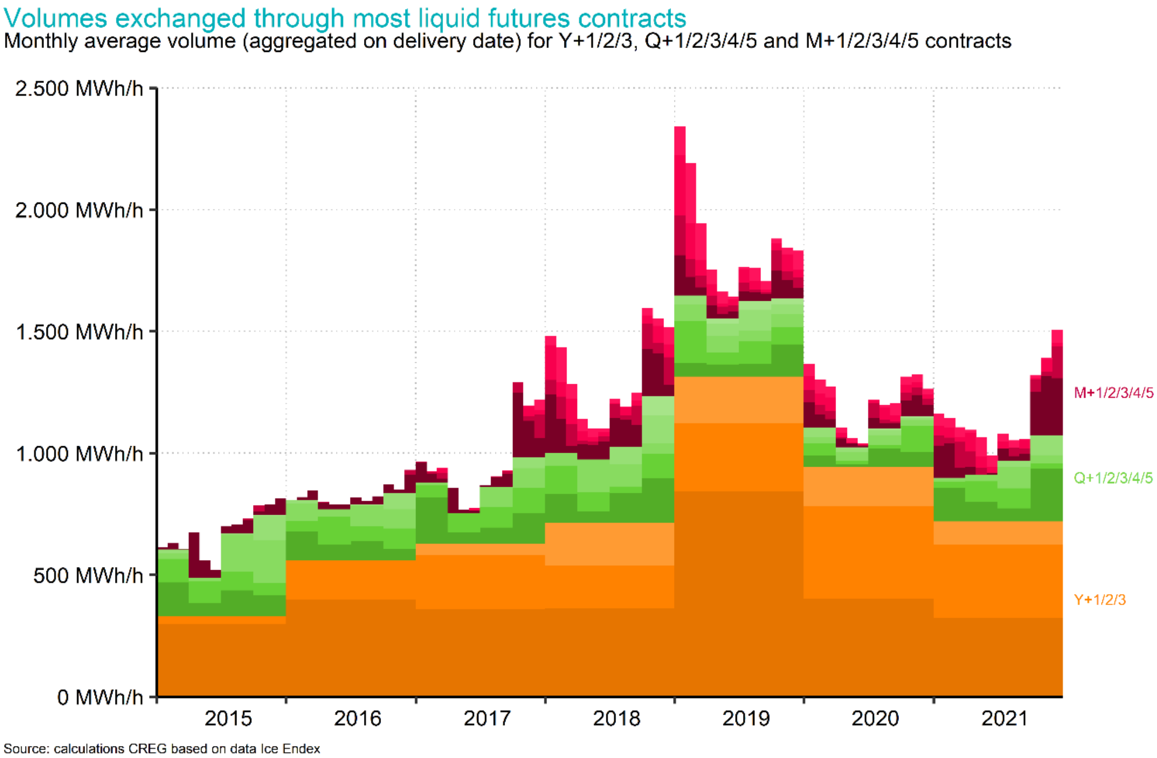


Figure 4-4 Volumes exchanged through most liquid futures contracts

4.2. CROSS-ZONAL LONG-TERM MARKETS

62. In order to secure access to cross-zonal transmission infrastructure in the timeframes before the spot markets, European TSOs (including Elia) have developed mechanisms to allocate yearly and monthly interconnection capacity through explicit auctions. These explicit auctions allow market participants to obtain the right to nominate electricity exchanges at the delivery date (in the case of PTR-UIOSI) or receive the day-ahead market spread for the entire volume of their purchased capacity (in the case of FTR Options). This section summarizes the allocation of cross-zonal capacity by Elia on its interconnections with other bidding zones.

4.2.1. Yearly allocation

63. This subsection shows the results for the explicit auctions for yearly cross-zonal capacity on the borders between Belgium on the one hand, and France, the Netherlands, Great-Britain and Germany on the other hand. These auctions are usually organized by JAO in the month of November preceding the year of delivery[12] and the results are subsequently published on JAO's web site.[13]

[12] Different timings may apply, notably for long-term capacity auctions over the Nemo Link interconnector with Great-Britain, where the calendar deviates from the usual auction timings on continental borders (https://www.nemolink.co.uk/trade-with-us/#auction-schedule)
[13] https://www.jao.eu/auctions#/

64. The allocated volumes for yearly cross-zonal capacity on the border with France have historically been relatively stable in the import direction: in 2021, 1.400 MW was available for cross-zonal trade. These values are significantly lower in the export direction, where only 200 MW was sold through the explicit auctions. The allocated volumes on the French border (in both directions) are shown in the top panel of Figure 4-5.

The bottom panel shows the resulting marginal price. Market participants who submitted bids at prices at least equal to the marginal price obtained cross-zonal capacity as a result. This marginal price is determined at the intersection between the inelastic supply curve (i.e. the offered capacity) and the demand (i.e. the bids introduced by market participants, ordered from high to low price). Year-to-year fluctuations are much more pronounced in the prices than in the volumes: these prices are the result of the market participants' expectations of the price spread (and its volatility) in the relevant market time unit. For the 2021 timeframe, prices for annual cross-zonal capacity on the Belgian-French border amounted to 4,87 €/MWh and 0,86 €/MWh in the export and import direction, respectively. The spread between both directions has increased significantly in the auction for 2022: 29,23 €/MWh for export capacity and 1,75 €/MWh for import capacity.

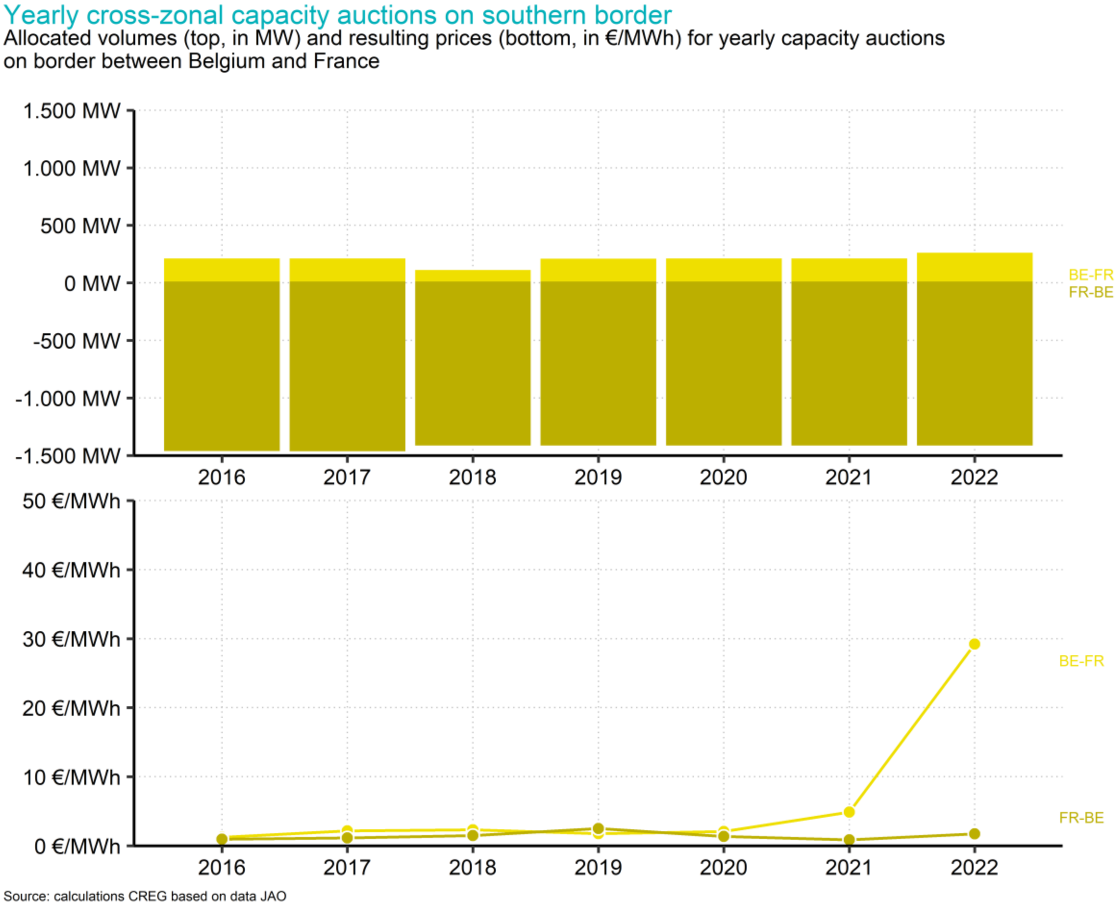


Figure 4-5 Yearly cross-zonal capacity auctions on southern border

65. On the northern border with the Netherlands, cross-zonal capacities are sold in a more even manner between the import and the export direction. Allocated capacities reached 473 MW in both directions. These values have been nearly identical since 2010.[14]

This does not imply stable prices: since 2016, prices fluctuate between 1 and 5 €/MWh. The cost for yearly cross-zonal capacity amounted to 2,16 €/MWh in the export direction or 2,14 €/MWh in the import direction.

These results are summarized in Figure 4-6.

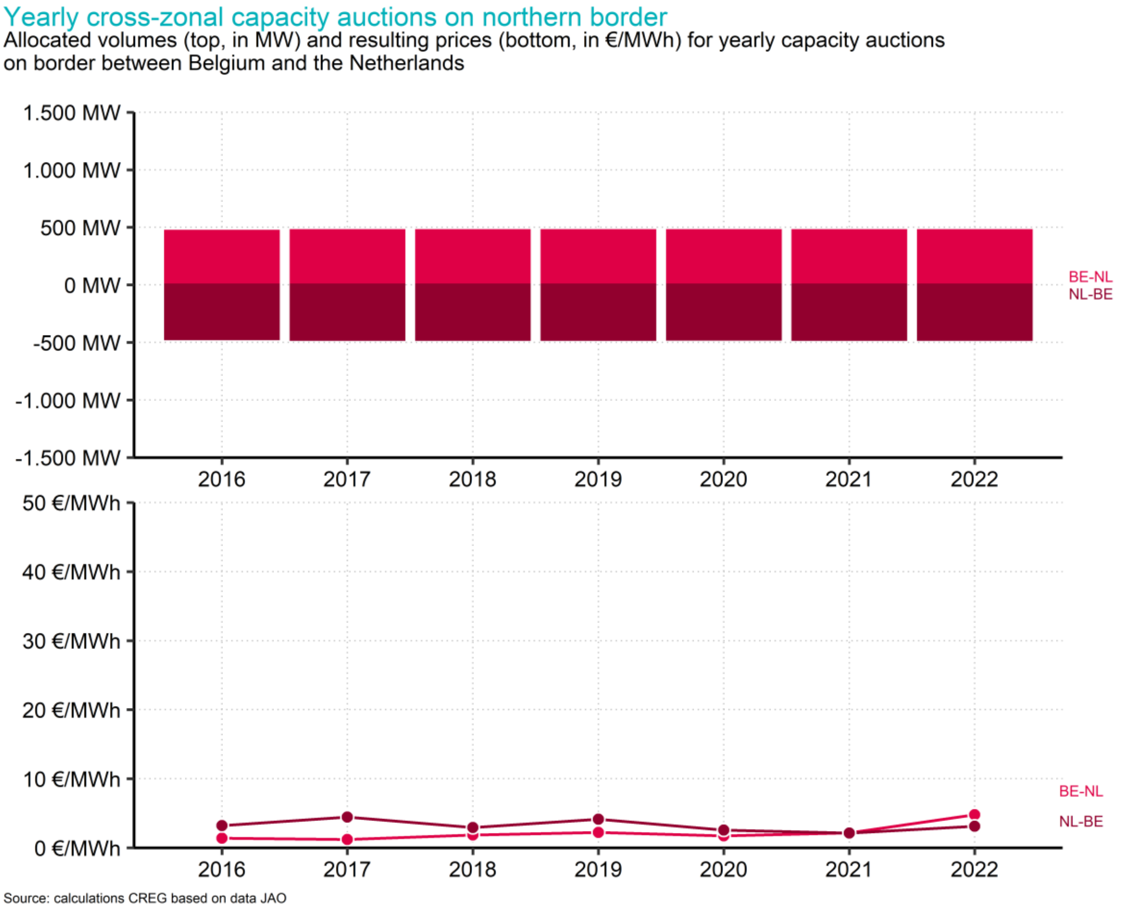


Figure 4-6 Yearly cross-zonal capacity auctions on northern border

[14] Even though the historical data is only shown since 2016: a more comprehensive overview of historical cross-zonal capacities is available in the Monitoring Report 2020.

66. On the border with Great-Britain, data for the yearly allocations is only available since the end of 2019 (the auction held was for 2020), as the Nemo Link interconnector only became operational in early 2019. The allocated capacities reached 100 MW (export) and 99 MW (import) for 2020, rising to 600 MW for both directions in 2021 and even further to 675 for both directions in 2022.

These relatively high allocated capacities (compared to the total available capacity of the interconnector of 1.012 MW) in the year-ahead timeframe are the result of the commercial strategy of Nemo Link, agreed with the relevant TSOs (Elia and National Grid). These auctions are held at different times throughout the year preceding the delivery: the volumes shown in Figure 4-7 are the total of all auctions for a specific yearly timeframe.

These auctions resulted, in 2021, in marginal prices which were significantly higher in the export direction (9,21 €/MWh) than in the import direction (0,36 €/MWh). This gap increased further for 2022, to 12,71 €/MWh for export and 0,16 €/MWh for import.

This matches the observed patterns in the day-ahead timeframe (see also chapter 5): Nemo Link is structurally used in the export direction, to transport electricity from Belgium to Great-Britain. This explains the higher value which market participants attach to capacity in the export directions, reflected in their bids for capacity in the explicit auctions. In turn, the desire to export electricity results from the observed price differences in the day-ahead timeframe.

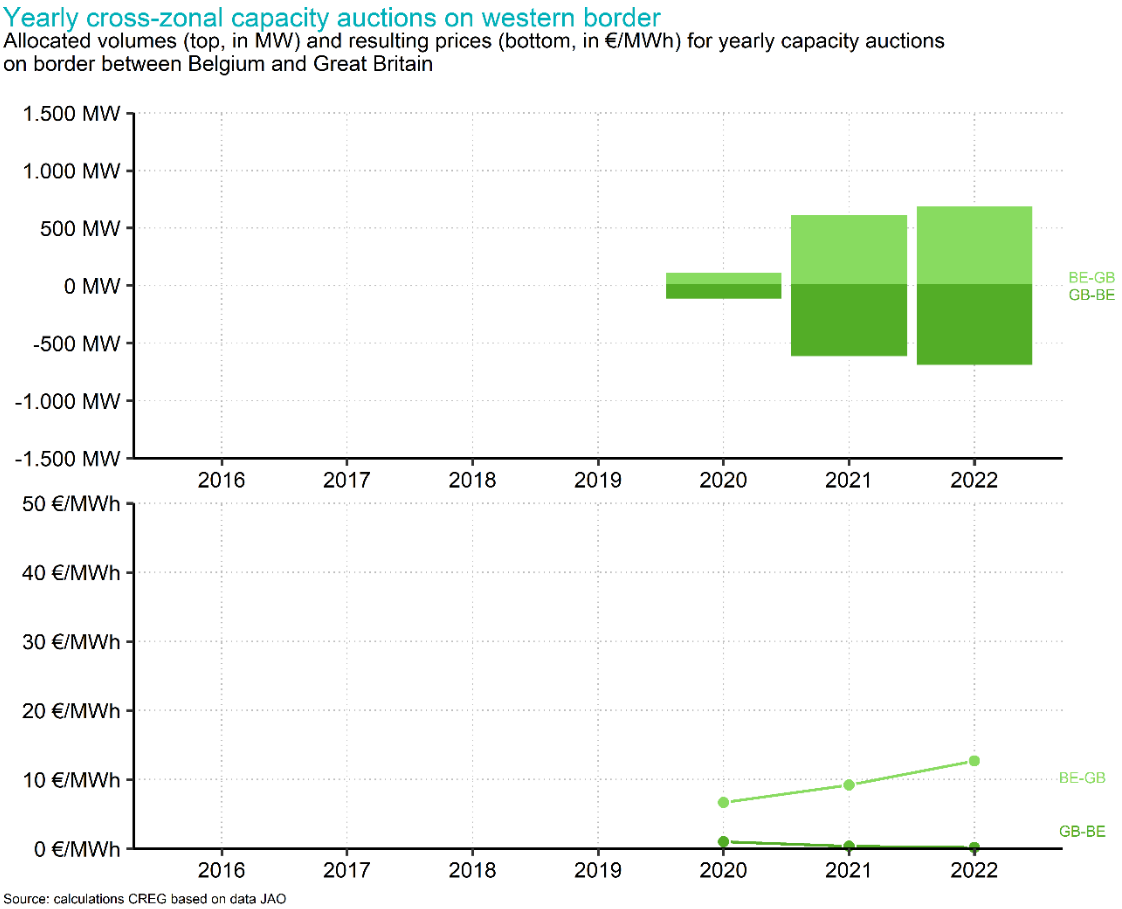


Figure 4-7 Yearly cross-zonal capacity auctions on western border

67. Finally, the results for the yearly cross-zonal capacity auctions on the ALEGrO interconnector for the 2022 timeframe is shown in Figure 4-8. The first annual auctions were organized in November 2021, as the interconnector entered into operations at the end of 2020, i.e. too late for organizing yearly auctions for 2021. In the export direction, 260 MW was sold at a marginal price of 5,16 €/MWh, while for the import direction also 260 MW was sold, yet at a lower price of 4,26 €/MWh.

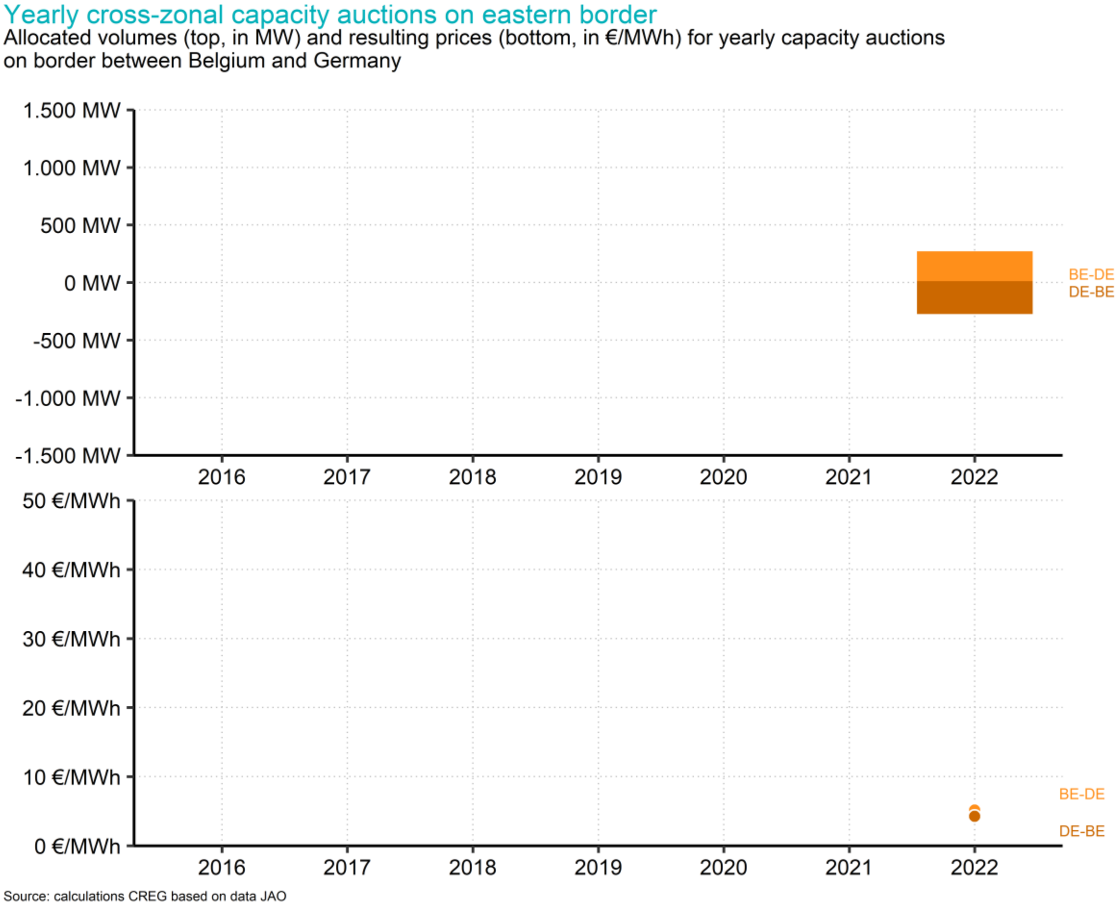


Figure 4-8 Yearly cross-zonal capacity auctions on eastern border

4.2.2. Monthly allocation

68. In this section, the explicit auctions for monthly cross-zonal capacity on Belguim's borders are summarized. As for the yearly auctions, these are organized and results are published on JAO, generally a couple of days before the start of the delivery month. The following figures show the results of the capacity auctions on the borders with France, the Netherlands, Great Britain and Germany.

69. The volumes of monthly cross-zonal capacity auctions in both the import and export direction from and towards France have, in 2021, varied between 200 and 250 MW. The auctioned values are, usually, identical in both directions. While prices did not exceed 5 €/MWh in either direction between 2019 and 2020, these started rising in the export direction, reaching an all-time high of 47,43 €/MWh in December 2021, reflecting the market conditions with very high price differences and volatility of the price spreads between Belgium and France in the day-ahead timeframe. As this value does not exclusively reflect the positive price difference between the average day-ahead prices of both zones, it must include a significant risk premium, which is calculated by market participants in order to reflect the volatility of the price spread between both countries.

Figure 4-9 shows the monthly total allocated volumes (top panel, in MW) and the resulting marginal prices (bottom panel, in €/MWh).

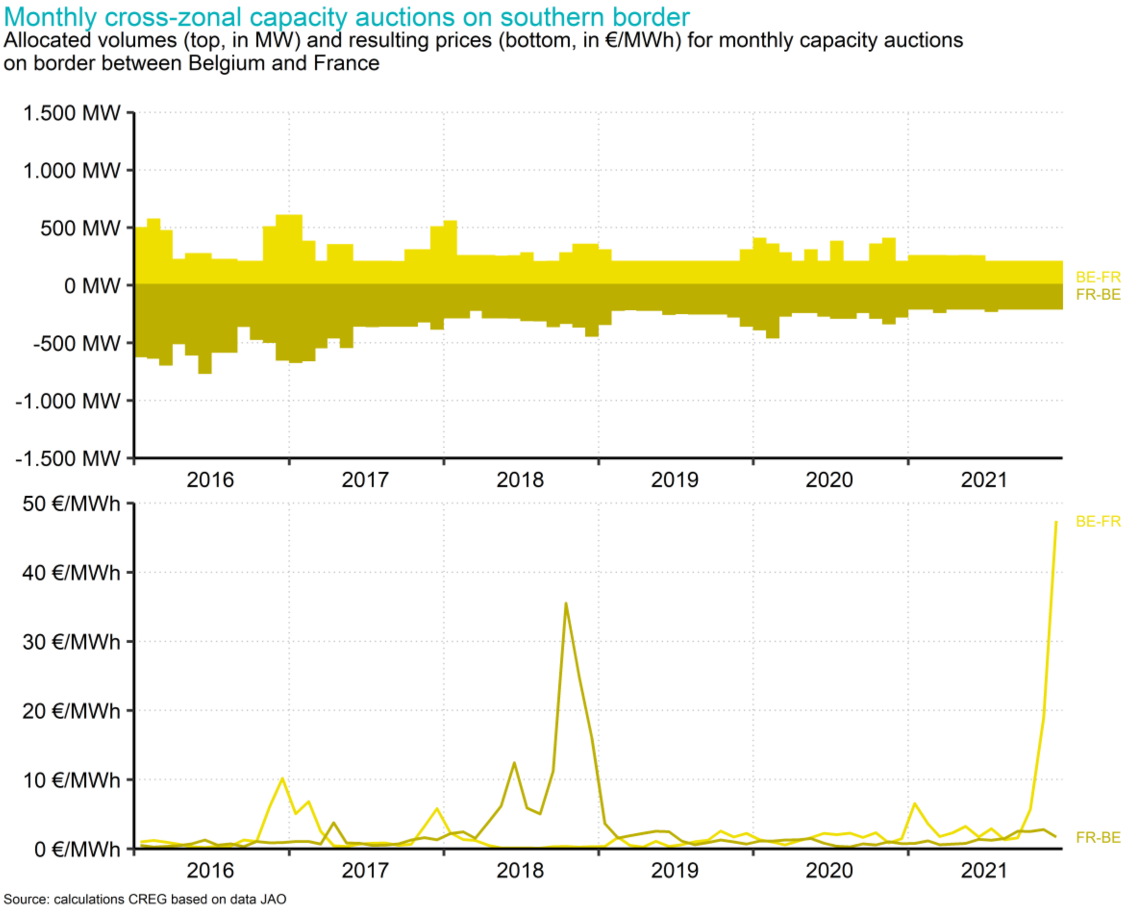


Figure 4-9 Monthly cross-zonal capacity auctions on southern border

70. Figure 4-10 shows, for the northern border with the Netherlands, the results of the monthly cross-zonal capacity auctions. The allocated volumes usually ranged, in 2021, between 100 and 200 MW in either direction, with some outliers reaching 300 MW (notably for delivery in May and December). The resulting capacity prices also started rising towards the end of the year, nevertheless to a much more reduced extent than on the southern border. In December, the price for import (10,56 €/MWh) exceeded the price for export capacity (4,52 €/MWh), despite being lower for the better part of the rest of the year.

71. Generally, when prices in one direction are relatively high, the prices in the other direction tend to move towards 0 €/MWh: this shows that market participants most often have a desire to trade in one direction which corresponds with their estimation of the average day-ahead price spread in the delivery month. This pattern is apparent on other borders as well but is more pronounced for monthly auctions than for yearly.

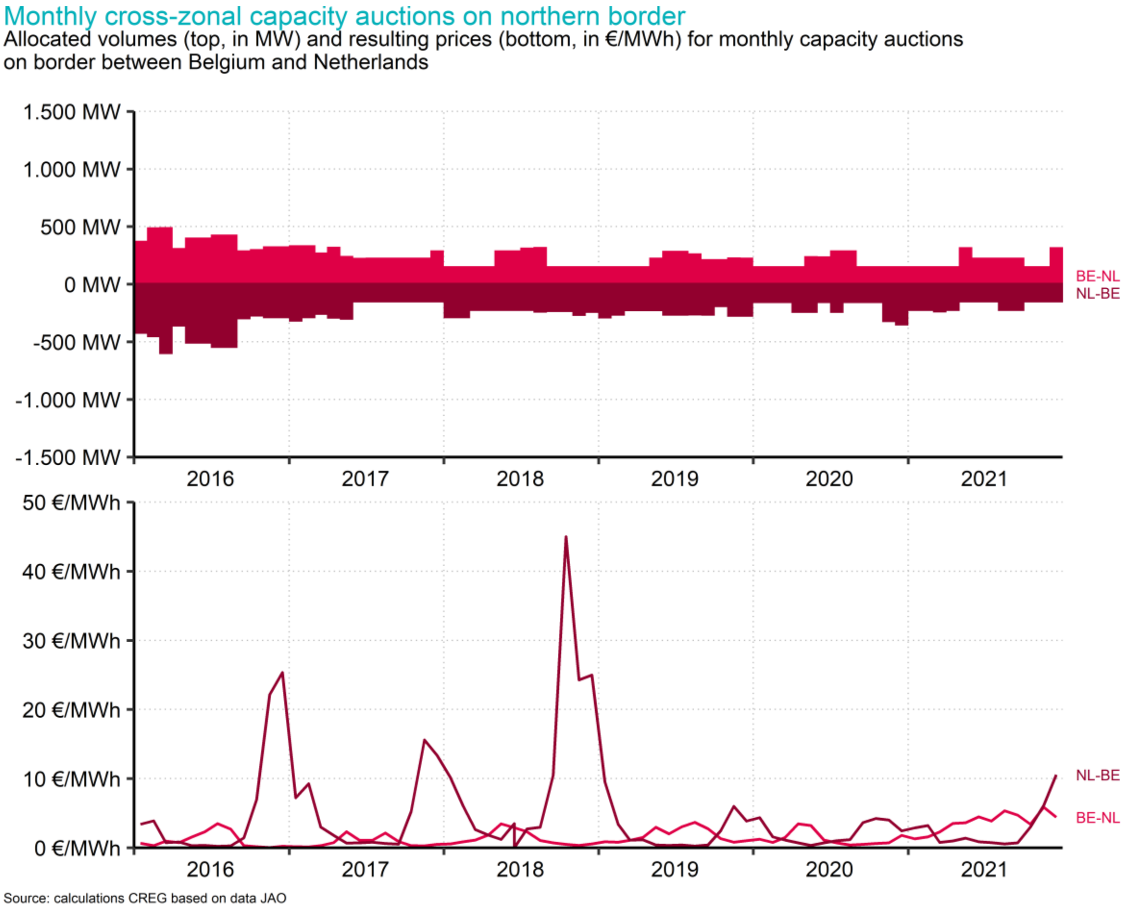


Figure 4-10 Monthly cross-zonal capacity auctions on northern border

72. On the western border with Great Britain, allocated volumes in 2019 and 2020 usually ranged between 75 and 200 MW in both directions, in a more or less symmetrical manner. In 2021, higher volumes were allocated in the monthly timeframe (reaching 579 and 590 MW in November and December, respectively). These auctions were organized by Nemo Link in order to secure income from the monthly timeframes, as the prices for export capacity significantly increased reflecting the absolute price differences and its volatility in the later months of 2021. The highest observed capacity price reached 38 €/MWh in November 2011.

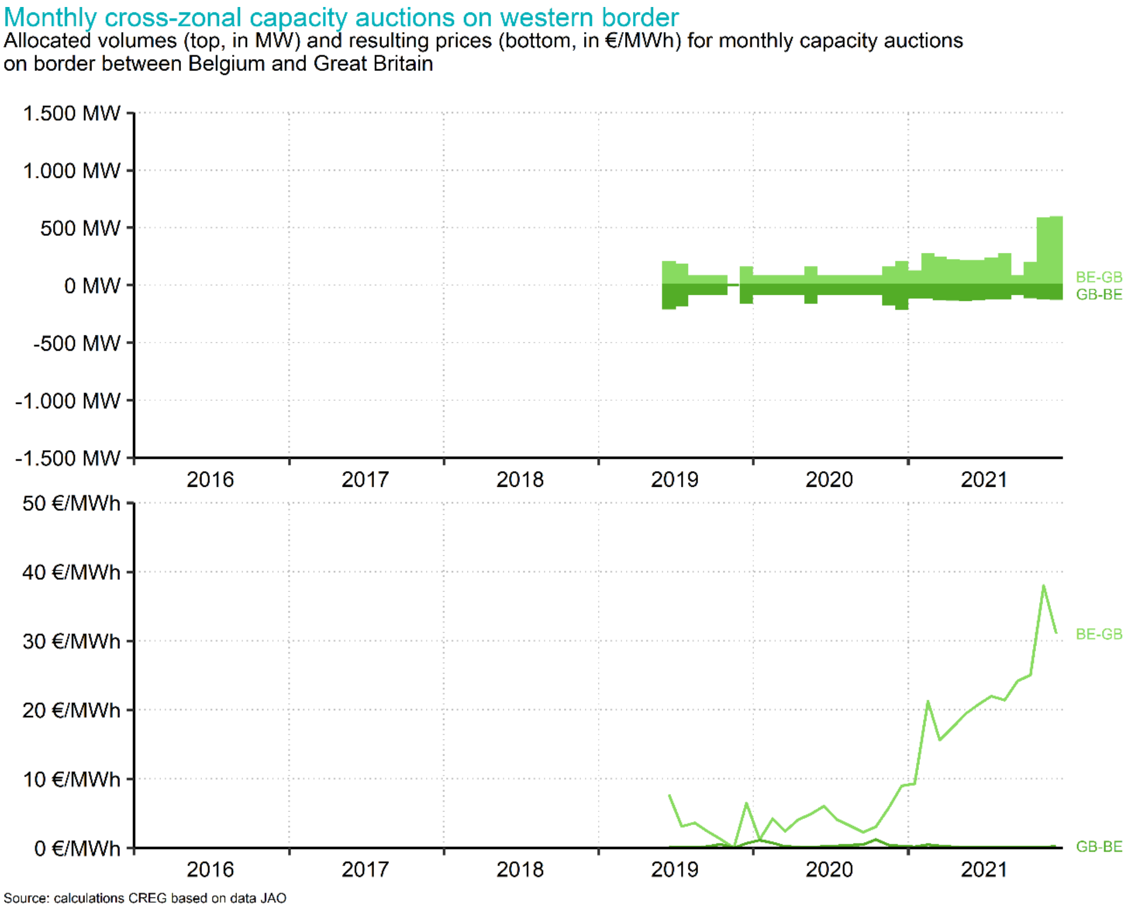


Figure 4-11 Monthly cross-zonal capacity auctions on western border

73. Finally, between 400 and 500 MW of monthly cross-zonal capacity was auctioned in 2021 on the ALEGrO interconnector. Here, the price increases in the day-ahead timeframe are reflected in the high values of the cross-zonal capacity in the import direction in the last months of 2021. This is explained by the relatively strong export position of the German/Luxembourgish bidding zone in the day-ahead timeframe, driven by the lower average prices.

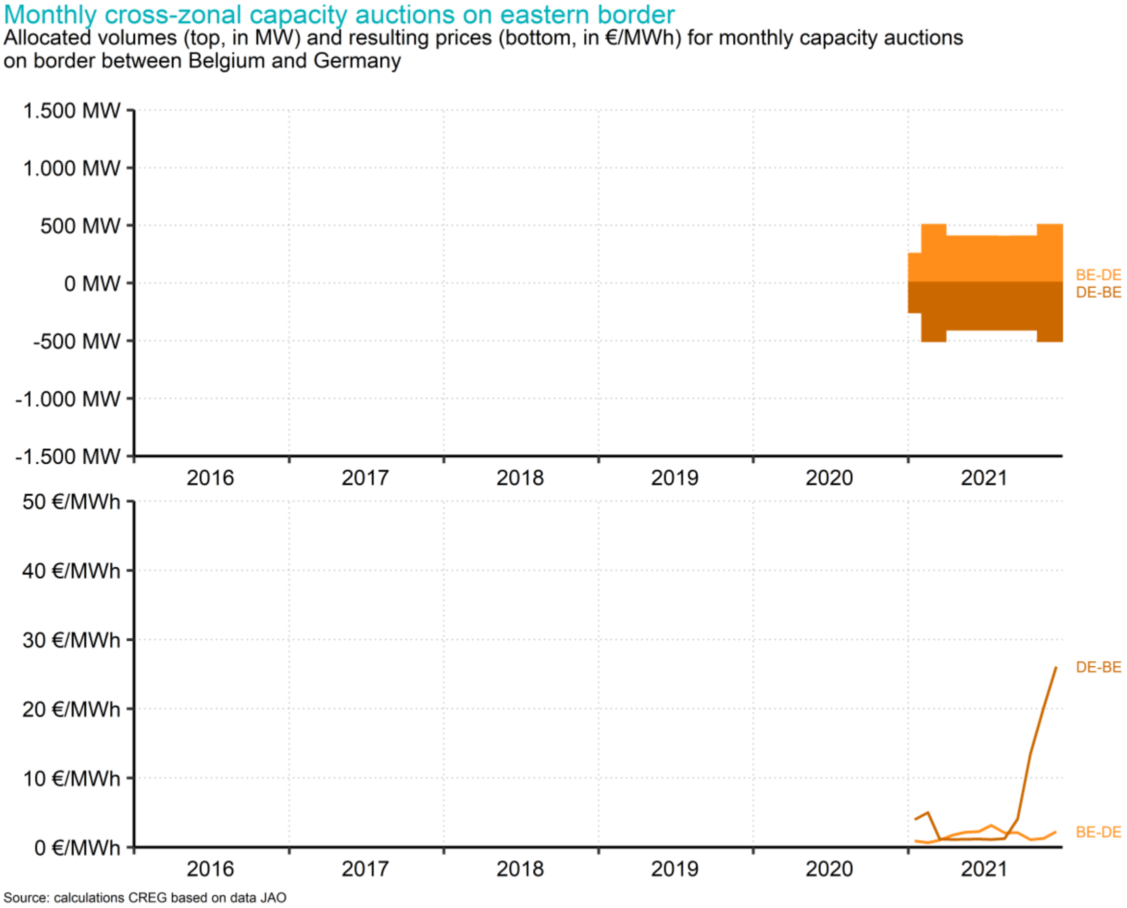


Figure 4-12 Monthly cross-zonal capacity auctions on eastern border

4.2.3. Other timeframes

74. In addition to the capacities sold through the yearly and monthly auctions, it is possible to buy long-term cross-zonal capacities for the quarterly timeframe, but only on the Nemo Link interconnector. Figure 4-13 shows, in a similar manner as in the previous section, the results of these auctions on the border with Great Britain. On average, between 75 and 150 MW of cross-zonal capacity for both directions were auctioned, resulting in prices reaching, for the export direction, a highest value of 17,45 €/MWh for the fourth quarter of 2021.

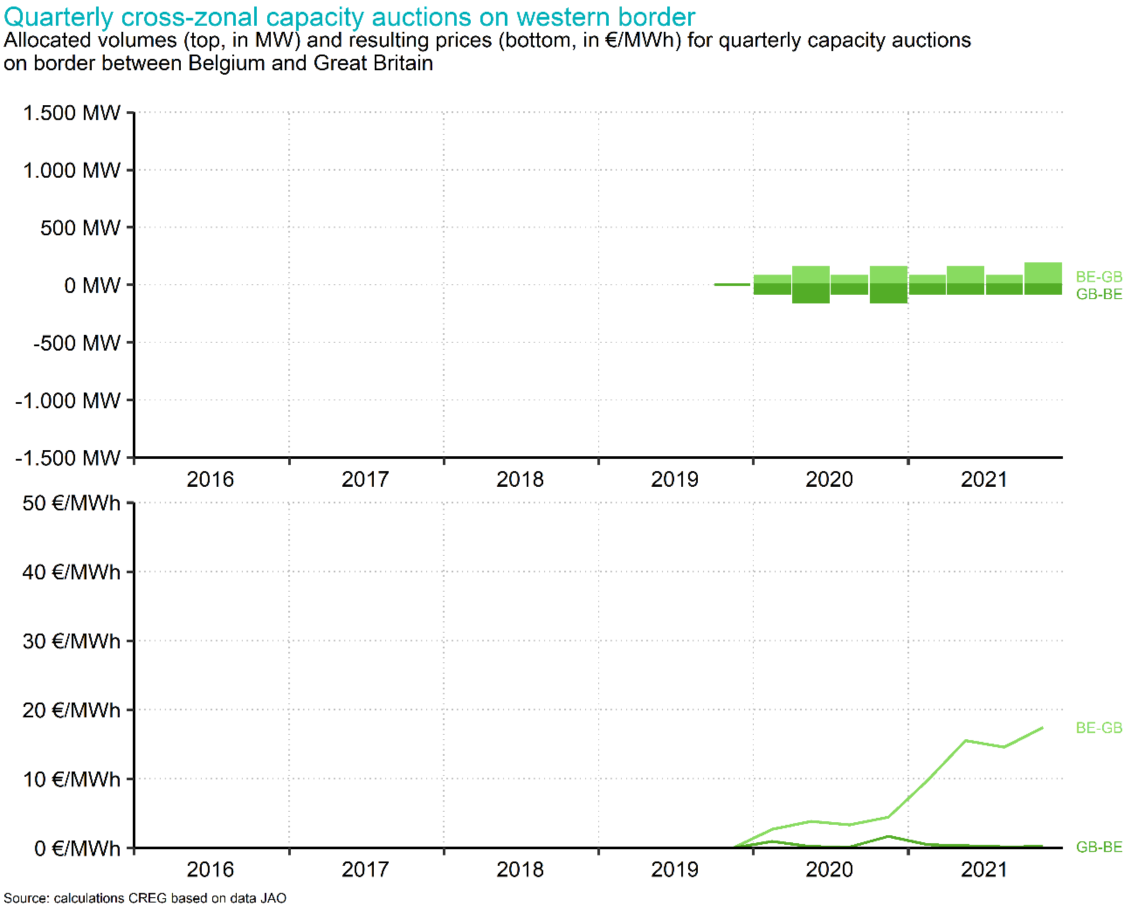


Figure 4-13 Quarterly cross-zonal capacity auctions on western border

4.2.4. Requested cross-zonal capacities

75. Figure 4-14 shows, for each border and direction, the difference between the average allocated and requested capacities from yearly, quarterly and monthly auctions, for delivery in 2021. Generally, market participants desire to acquire much more capacity than the volumes offered by Elia. Depending on the considered border, direction and timeframe, the requested capacities are about 10 to 15 times higher than what is made available.

This is the result of the practice where, based on its availability planning, Elia calculates the offered long-term cross-zonal capacity well in advance of the delivery period. The supply of cross-zonal capacity is therefore independent of its price: supply may be seen as completely inelastic and the capacity price is determined at the intersection with the demand curve, constructed by ordering the market participants' bids for capacity by decreasing price.

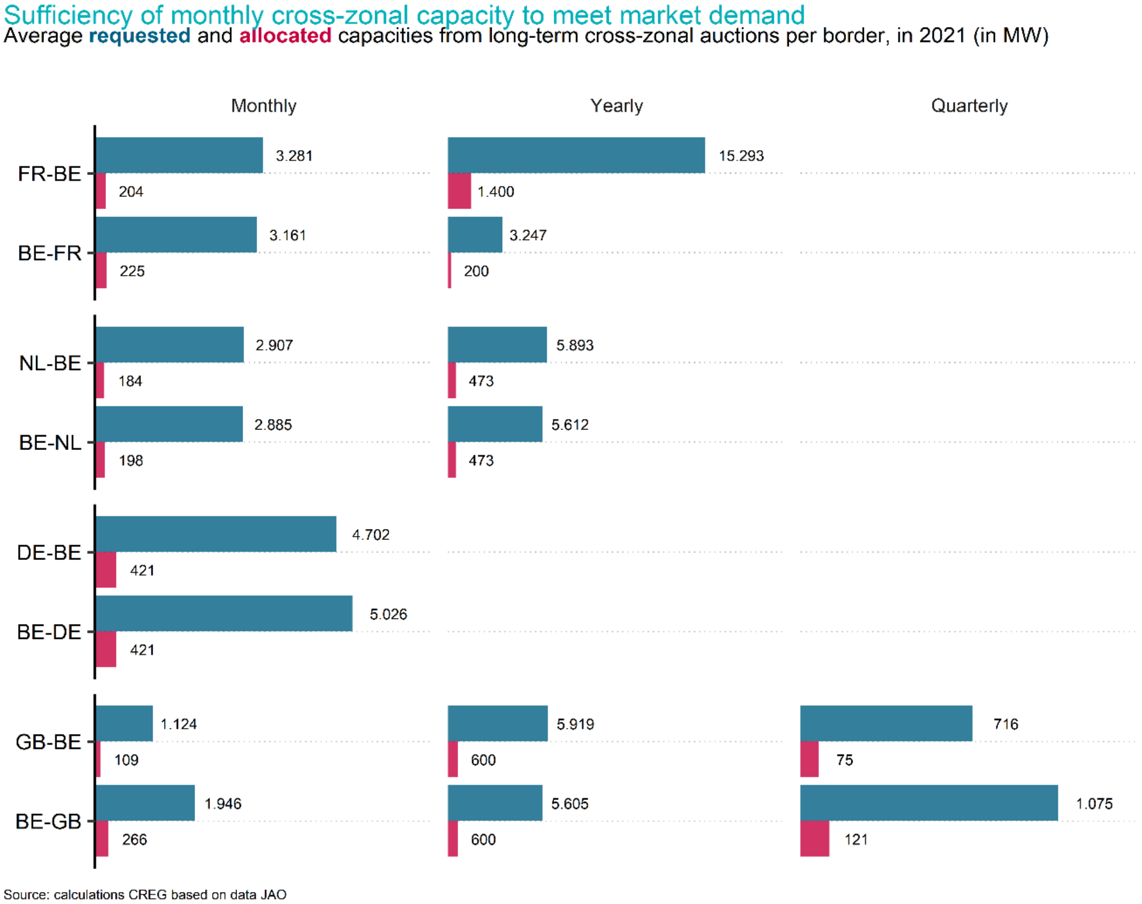


Figure 4-14 Sufficiency of monthly cross-zonal capacity to meet market demand

4.2.5. PTR nomination rates

76. Long-term cross-zonal capacities (for any of the relevant timeframes) are usually sold as transmission rights. Basically, two types exist in Belgium. On the borders with the Netherlands, France and Germany, "Financial Transmission Rights – Options" ("FTR-Options") are sold. The holder of these rights are remunerated for their entire capacity in case of a positive price spread between the two relevant bidding zones. Hence, there is no need for these FTR-Option holders to nominate their energy exchanges, as they are fully hedged against the price spread. On the border with Great Britain, however, "Physical Transmission Rights with Use-It-Or-Sell-It principle" (PTR-UIOSI) are used to allocate capacity. The holders of these rights have the choice of either to nominate their transmission rights before the long-term nomination closing gate (typically shortly before the start of the day-ahead market) or decide to return their rights to the Explicit Day-Ahead auction and get remunerated the clearing price. Note: this PTR-UIOSI principle was also in place on the other Belgian borders until …..

77. As we will see in the following chapter, the trading regime in the day-ahead timeframe changed significantly since the Brexit. In short, the day-ahead implicit market coupling was replaced with an explicit mechanism. At the same time, the remuneration of these long-term transmission rights no longer reflected the day-ahead price spread between both countries (as these were no longer implicitly coupled) but the clearing price of the day-ahead explicit capacity auction. Assuming that a market participant can accurately predict the direction of the day-ahead market spread, it is in general more profitable to nominate the electricity exchange for PTR-UIOSI holders under these new trading arrangements as the clearing price of the DA Explicit auction is on average lower than the loss adjusted market spread. Before the Brexit, there was no real incentive for PTR-UIOSI holders to nominate their exchanges, as their remuneration was, in any case, linked to the day-ahead market spread, even for non-nominated volumes.

78. This is reflected in the evolution of the nomination rate in Figure 4-15. Before 2021, long-term rights were never nominated. Since 1 January 2021 (i.e. the effective Brexit date), the nominations of long-term export rights increased significantly, reaching about 600 MWh/h (or about 60% of the total capacity) on average in most months.

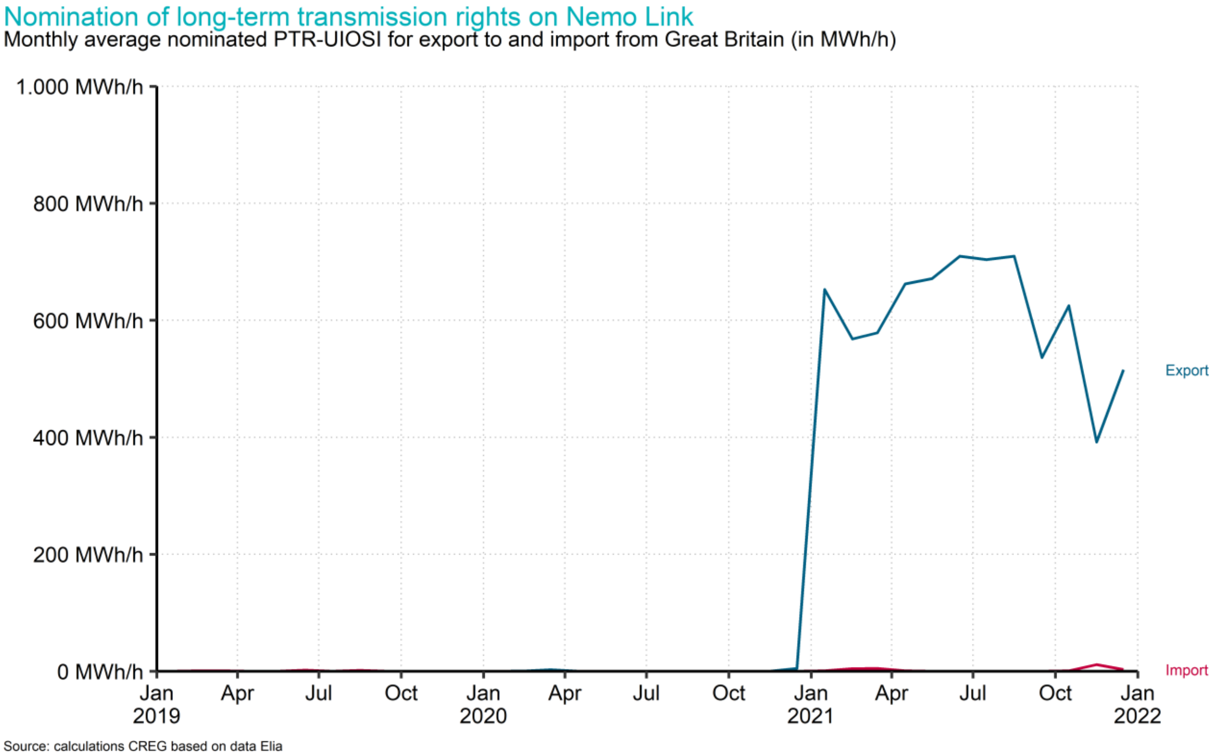


Figure 4-15 Nomination of long-term transmission rights on Nemo Link

5. DAY-AHEAD MARKETS

79. In Belgium, trading in the short-term (day-ahead) timeframe takes place in a market coupled with other European countries (bidding zones). The *Single Day-Ahead Coupling* (SDAC) is a single, pan-European market where transmission capacity is allocated through an implicit coupling mechanism. This mechanism, using the algorithm *Euphemia*, calculates prices and net positions of all the participating bidding zones in a single optimization round.

80. In July 2019, the *Multi-NEMO Arrangements* (MNA) were launched, allowing competition between the Nominated Electricity Market Operators (NEMOs). Since then, market participants in Belgium have the choice to participate to the SDAC through one of the two designated NEMOs in Belgium: EPEX SPOT (the historical incumbent power exchange) and Nord Pool (the new entrant since the MNA go-live). For the first time, this section of the yearly Monitoring Report compares the data from both exchanges, in order to provide as complete a view as possible on the functioning of the Belgian day-ahead markets.

81. In the day-ahead timeframe, cross-zonal capacities are calculated and allocated in two ways, depending on the considered borders:

- Through the Central-West Europe Flow-Based Market Coupling (CWE FBMC), where capacities are calculated and allocated in an explicit manner (as part of the SDAC) between Belgium, France, the Netherlands, Germany/Luxembourg and Austria.[15]
- Through an explicit mechanism, whereby capacities on the Nemo Link interconnector are calculated via a (coordinated) Net Transfer Capacity approach. Market participants may purchase transmission rights on this border, giving them the right to nominate their energy exchanges. This mechanism replaces the implicit coupling under the SDAC since the departure of the United Kingdom form the European Union and the Internal Energy Market.

Both market coupling arrangements are analyzed in the remainder of this chapter.

5.1. EXCHANGED VOLUMES

5.1.1. Belgian order books

82. In the Belgian day-ahead market, two NEMOs are active. Market participants submit their bids for buying or selling electricity, after which both NEMOs aggregate their order books and match the supply and demand curve, taking into account cross-border transmission capacity in order to allow for the import and export of electricity with other coupled bidding zones in the CWE FBMC. At the intersection of these curves, the exchanged volumes and corresponding prices are determined.

83. Figure 5-1 shows the evolution of the monthly total exchanged volumes.[16] These volumes vary, typically, between 1.000 and 2.000 GWh, with relatively high volumes observed in the second half of 2018. Since 2020, data is available for Nord Pool volumes as well, these are added in blue to the graph. The volumes exchanged through the Nord Pool trading platform increased from early 2020 (around

[15] From the second quarter of 2022 onwards, the CWE FBMC will cease to operate after the go-live of the Core FBMC, coupling the former CWE bidding zones with the bidding zones of Slovakia, Slovenia, Croatia, Hungary, Czech Republic, Poland and Romania.

[16] Calculated as the highest of the buy and sell volumes, per NEMO.

100 MWh per month) to the end of 2021 (about 200 MWh per month), with temporary peaks to 275 MWh per month at the start of 2021.

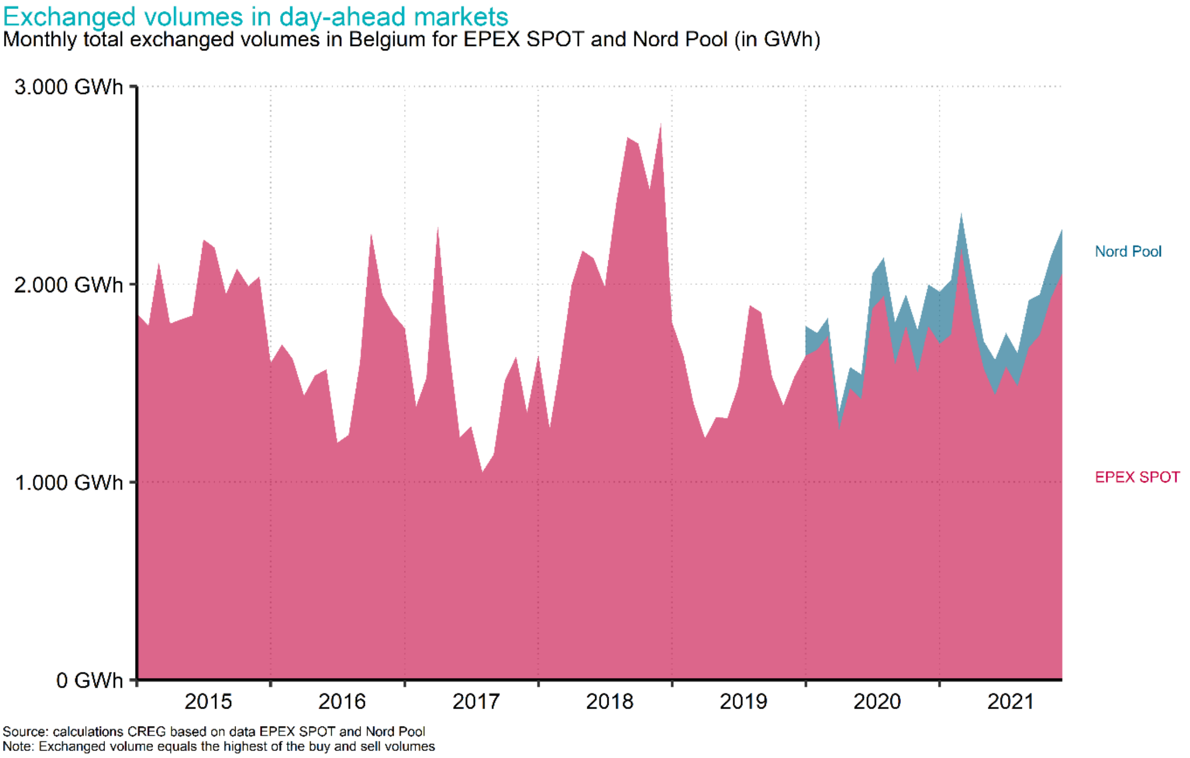


Figure 5-1 Exchanged volumes in day-ahead markets

84. In general, the market share of the incumbent NEMO, EPEX SPOT, remains much higher than the one of the new entrant, Nord Pool (89,3% versus 10,7% in 2021). Market shares of both exchanges have converged slightly between 2020 and 2021. Table 5-1 shows the total traded volumes in the Belgian day-ahead markets, per NEMO. In 2021, this volume amounted to 23,4 TWh which is slightly more than a quarter (27,7%) of the Belgian total demand for electricity (84,4 TWh in 2021, see chapter 1).

(in TWh)	2015	2016	2017	2018	2019	2020	2021
Nord Pool						1,8	2,5
EPEX SPOT	23,7	19,6	17,9	25,9	18,4	19,8	20,9

Source: calculations CREG based on data EPEX SPOT and Nord Pool

Table 5-1 Yearly exchanged volumes in day-ahead markets

5.1.2. Cross-border net positions

85. The net position of a bidding zone is determined by the market coupling process through the *Euphemia* algorithm. The evolution of this net position is shown, for Belgium, in Figure 5-2. The observed monthly averages as well as the highest and lowest observed net positions were, in 2021, in line with the observations in 2020. The single exception is September 2021, where on average 1.468 MW was imported to Belgium in the day-ahead timeframe. This was largely due to the high prices in Belgium compared to other CWE bidding zones during that monthly, as will be explored further in this chapter.

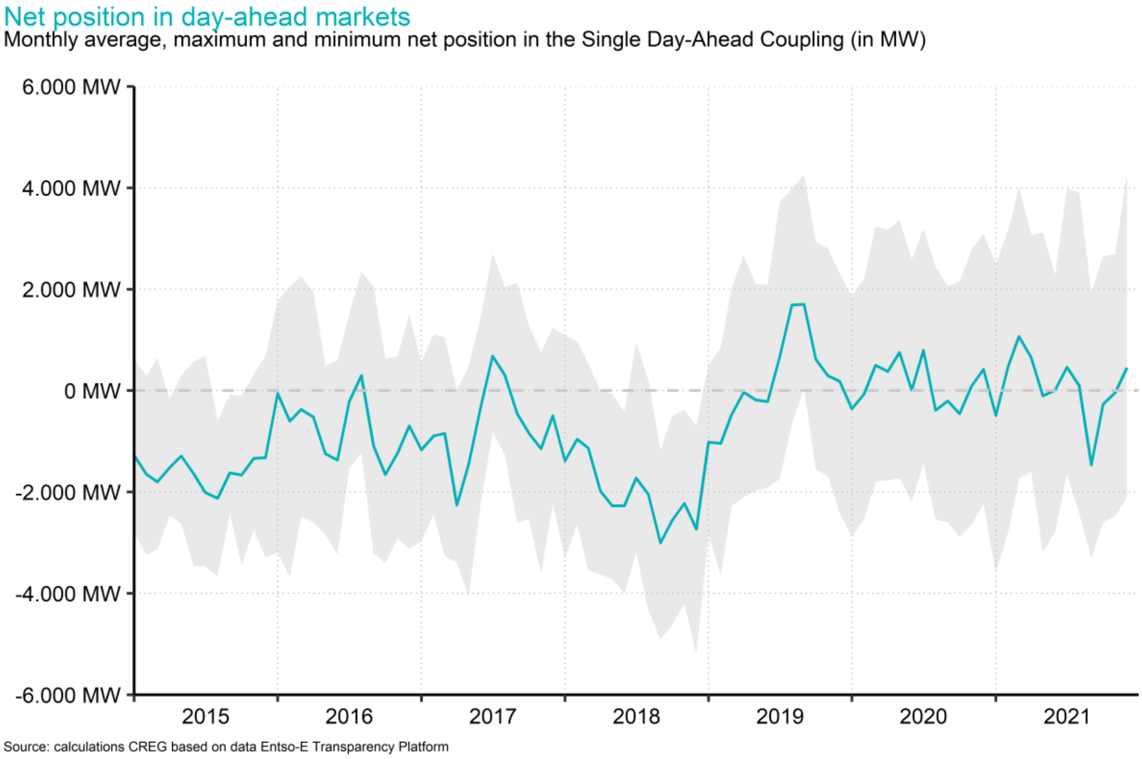


Figure 5-2 Net position in day-ahead markets

86. Globally, Belgium remained a net exporter in the SDAC in 2021, just as in 2019 and 2020, as may be observed in Table 5-2. A record-high net exporting position was achieved in December 2021, reaching 4.289 MW. These numbers follow the long-term trend since 2015, were after years of importing very big volumes in the day-ahead timeframe (reaching a peak of 2.030 MW on average in 2018), Belgium became a structurally exporting country.

(in MWh/h)	2015	2016	2017	2018	2019	2020	2021
Average net position	-1.607	-728	-736	-2.030	189	123	70
Maximum net position	683	2.348	2.702	1.084	4.262	3.357	4.289
Minimum net position	-3.656	-3.668	-4.069	-5.196	-3.630	-2.892	-3.581

Source: calculations CREG based on data Entso-E Transparency Platform

Table 5-2 Evolution of yearly average, maximum and minimum net position of Belgium in SDAC

87. The fact that the numbers for 2021 are similar to those of 2019 and 2020 is remarkable, as the United Kingdom left the Internal Energy Market on 1 January 2021, hence it is no longer included in the SDAC. As we will see later on, significant volumes were exchanged with the bidding zone of Great-Britain, mostly in the export direction in 2021. These volumes are no longer included and need to be added to the net position of Belgium. In doing so, the hourly average net exporting position increases from 70 MW (SDAC-only) to 959 MW (including the average exports over Nemo Link, which reached 889 MW).

5.1.3. Post-Brexit trading arrangements with the United Kingdom

88. The withdrawal of the United Kingdom from the European Union has already been mentioned in the previous sections. Following the conclusions of the agreements between both parties, the United Kingdom no longer participates, since 1 January 2021, to the SDAC (and SIDC) in specific and the IEM in general.[17] As a result, capacities on the Nemo Link interconnector (between the Belgian and Great Britain bidding zones) are no longer allocated in an implicit manner. Instead, market participants who wish to trade electricity between both bidding zones need to conclude the steps in the following explicit allocation process[18]:

i. Purchase physical day-ahead transmission capacity rights via the Joint Allocation Office;

ii. Buy or sell energy in one of the two day-ahead electricity auctions (accommodated by EPEX SPOT or Nord Pool) for delivery in Great Britain; and

iii. Buy or sell energy in the SDAC auctions (accommodated by EPEX SPOT or Nord Pool) for delivery in Belgium (or other coupled bidding zones).

iv. Nominate physical day-ahead transmission capacity rights on the Regional Nomination Platform ("RNP").

89. As this process completely differs from and adds many complexities to the implicit coupling procedures in the SDAC, it may increase significant inefficiencies. This is, in particular, the case when market participants exchange energy against the market spread, as a result from a wrong forecast of the relative price levels in Belgium and Great Britain. These adverse flows historically did not occur often in the SDAC,[19] as there a socio-economic welfare optimization is done by a coupling algorithm that considers at the same time the interconnector capacities and the order books of the power exchanges.

90. The occurrence of such inefficiencies following the introduction of the explicit allocation mechanism is explored in Figure 5-3. Adverse flows may be observed in the upper right and lower left quadrant, as there the flows go from the higher-priced to the lower-priced zone. It is obvious that such hours were rather rare in 2019 and 2020, when Great Britain was still coupled under the SDAC. Since 2021 however, we notice a significant share of observations in these quadrants (mostly when traders export electricity even though prices in Belgium exceeded prices in Great Britain). These inefficiencies seem to increase when price spread levels are getting smaller, prices get less easy to forecast (e.g. due to high variability on commodity prices) or when within day flow reversals occur (more difficult to profile).

[17] This is the case even though Northern Ireland remains coupled in the SDAC and SIDC through the I-SEM (Integrated Single Electricity Market) between Northern Ireland and Ireland. Hence, it is more appropriate to refer to Great-Britain (the bidding zone) no longer participating to the SDAC / SIDC.

[18] While step ii and iii are done through EPEX SPOT or Nord Pool in the listed procedure, it could also be done over-the-counter (OTC) through a bilateral agreement between buyers and sellers, outside of organized marketplaces.

[19] Even though, in the CWE, the shift from so-called "flow-based intuitive" to "flow-based plain" introduced the possibility that counter-intuitive flows result from the SDAC. Counter-intuitive flows are not the same as adverse flows, though, as the former increase socio-economic welfare while the latter decrease it.

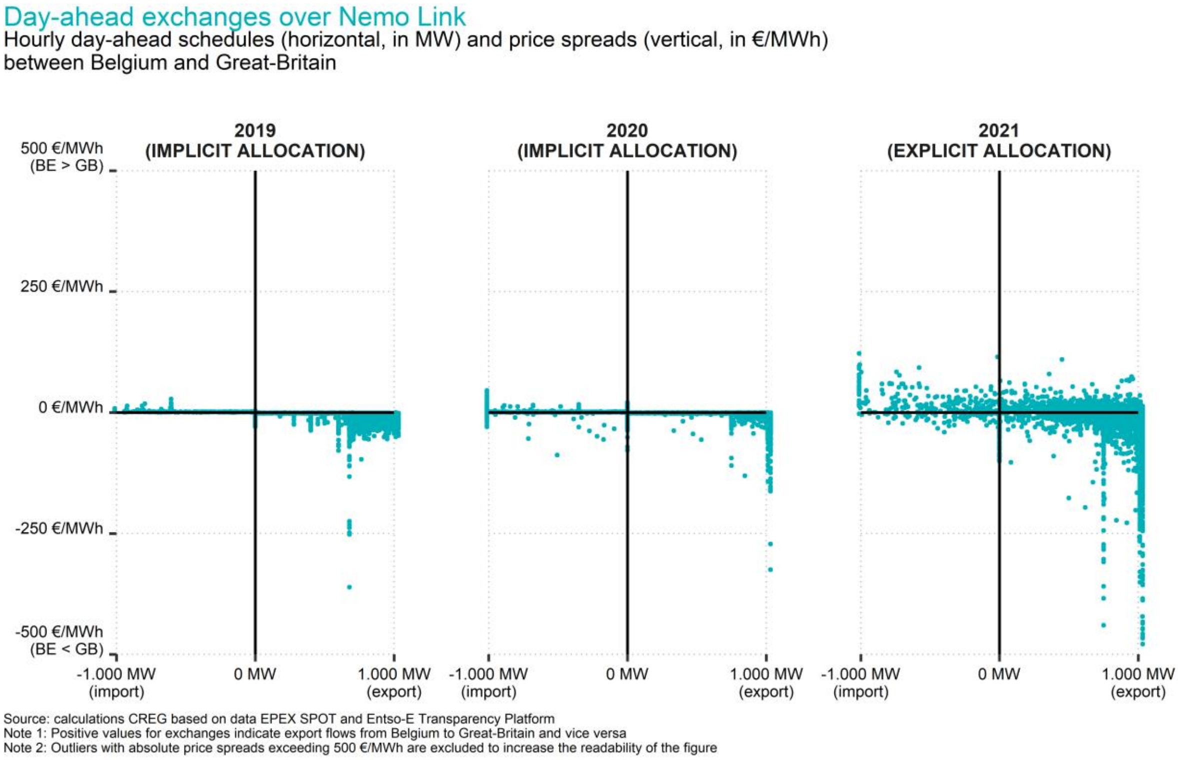


Figure 5-3 Day-ahead exchanges over Nemo Link

91. The value of these flows is calculated in Table 5-3 as the product of the exchanged volume (i.e. the day-ahead commercial schedule) and the price spread between both markets.[20] As was shown in the previous Figure 5-3, the number of hours with counter-intuitive flows increased strongly in 2021, from near zero to 11,2% of all hours. The resulting value increased even more strongly, to 5,6 M€. This increase partly results from the increase in hours with adverse flows, yet also partly due to the increased price convergence.

	2019	2020	2021
% of hours with exchanges against the day-ahead market spread	0,0%	0,5%	11,2%
Value of exchanges against the market spread *(exchange * price spread)*	9€	392.653€	5.633.362€
Value of exchanges with the market spread *absolute value of (exchange * price spread)*	62.791.307 €	72.070.772 €	301.275.236 €

Source: calculations CREG based on data Entso-E Transparency Platform

Table 5-3 Occurrence and value of exchanges against the market spread on Nemo Link

92. This sum clearly constitutes a welfare loss, introduced by the inefficiency of the explicit trading mechanism compared to the implicit mechanism, despite the best efforts of the involved parties (mainly Nemo Link) to allow for more efficient trading opportunities for market participants. It is difficult to estimate the net effect of a possible future reduction of the spreads between both day-ahead markets: on the one hand this increases the likelihood that market participants wrongly predict the direction in which they need to trade. On the other hand, the impact of such forecasting errors in welfare destruction decreases as the price spreads are lower. In any case, the efficiency of the explicit

[20] As no reference price exists, the GB prices are obtained from EPEX SPOT (and hence these prices exclude the volumes traded in Nord Pool's day-ahead auction).

trading mechanism remains a topic of continuous interest and effort for the CREG and the TSOs involved.

5.2. PRICES

93. The day-ahead electricity prices have been the topic of many studies, debates and policy initiatives in 2021. This section presents the evolution and distribution of the observed prices in Belgium and its neighboring countries, as well as some reflections on the increase in the occurrence in negative prices.

5.2.1. Price evolution

94. Figure 5-4 shows the evolution of the monthly average day-ahead prices in Belgium and its neighboring bidding zones (Great Britain and other CWE bidding zones). Following the all-time low values in 2020 as a result of the measures against the worldwide COVID-19 pandemic, prices in all considered bidding zones started picking up towards the end of 2020.

95. Fueled by drastically changing market fundamentals, in particular the strong increases in prices of natural gas, coal and CO_2 allowances, prices started reaching historically high levels. This effect was most pronounced from the second half of 2021 onwards and continues to this day. The CREG published, in October 2021, a study on the increase in electricity (and gas) prices in Belgium, where the movements of the electricity and gas prices as well as underlying commodities are presented.[21]

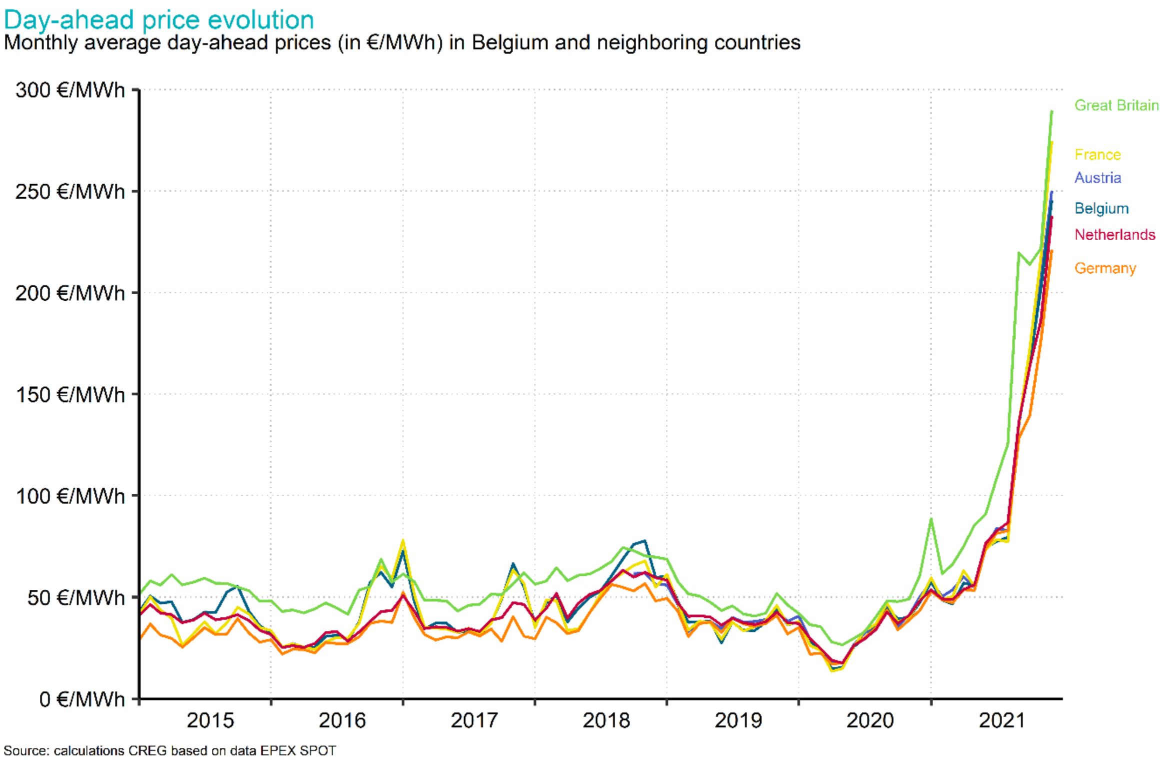


Figure 5-4 Day-ahead price evolution

[21] Study (F) 2289 on the increase in electricity and gas prices in Belgium

96. The average price across all hours of 2021 reached 104,1 €/MWh in Belgium, more than three times higher than the 31,9 €/MWh in 2020. Compared to a more historically robust average, from 2015 to 2021, prices increased with 147,5% or with a factor of nearly 2,5. This increase is significantly below the values for other countries, as shown in Table 5-4, yet this is also partly due to the relative position of the historical prices in Belgium over other countries (42,1 €/MWh, which is higher than all other bidding zones except Great Britain).

(in €/MWh)	Historical price (avg. 2015 – 2020)	Current price (avg. 2021)	Increase
Austria	39,2	106,9	+172,5%
Belgium	42,1	104,1	+147,6%
France	40,3	109,2	+170,7%
Germany	34,6	96,8	+180,2%
Great Britain	51,7	137,7	+166,4%
Netherlands	39,6	103,0	+160,1%

Source: calculations CREG based on data Entso-E Transparency Platform

Table 5-4 Increase of yearly average day-ahead prices compared to historical

97. Despite the very strong increases in the general price level, prices tend to follow the same up- and downward movements between different bidding zones. With the exception of Great Britain, average prices generally converge between Belgium and its neighboring countries. This is reflected in the increased convergence levels (explored further in section 5.3). This also follows from Table 5-4: average prices in 2021 are closer than was historically the case between 2015 and 2020, at least when considered relative to the general price level.

5.2.2. Price distribution

98. Monthly or yearly average prices do not provide the required granularity to efficiently steer investments in a liberalized markets. It is therefore of particular interest to have a look at absolute, mean, maximum and minimum prices that are observed on the day-ahead markets.

99. The yearly distribution of the observed day-ahead prices in Belgium and its neighboring countries is shown in Figure 5-5.[22] It is clear that for Belgium, but similarly for other bidding zones, the density curves shift to the left in 2019 and 2020 in comparison to previous years, in particular 2018 where relatively high prices were observed. This indicates that prices tended to decrease: both the average values as well as the observed minimum, maximum and mean prices were generally on the low side in 2019 and (especially) 2020.[23] This trend has come to an abrupt end in 2021: the occurrence of low and negative prices still persists but the occurrence of high and very high prices (from 100 €/MWh onwards) increased sharply.

[22] At least those within the range between -50 and 300 €/MWh. Higher (and lower) prices were, very rarely, observed, yet are not included in order to increase the readability of the figure.

[23] Average prices are shown, in Figure 5-5, as the black dots at the bottom of the density curves.

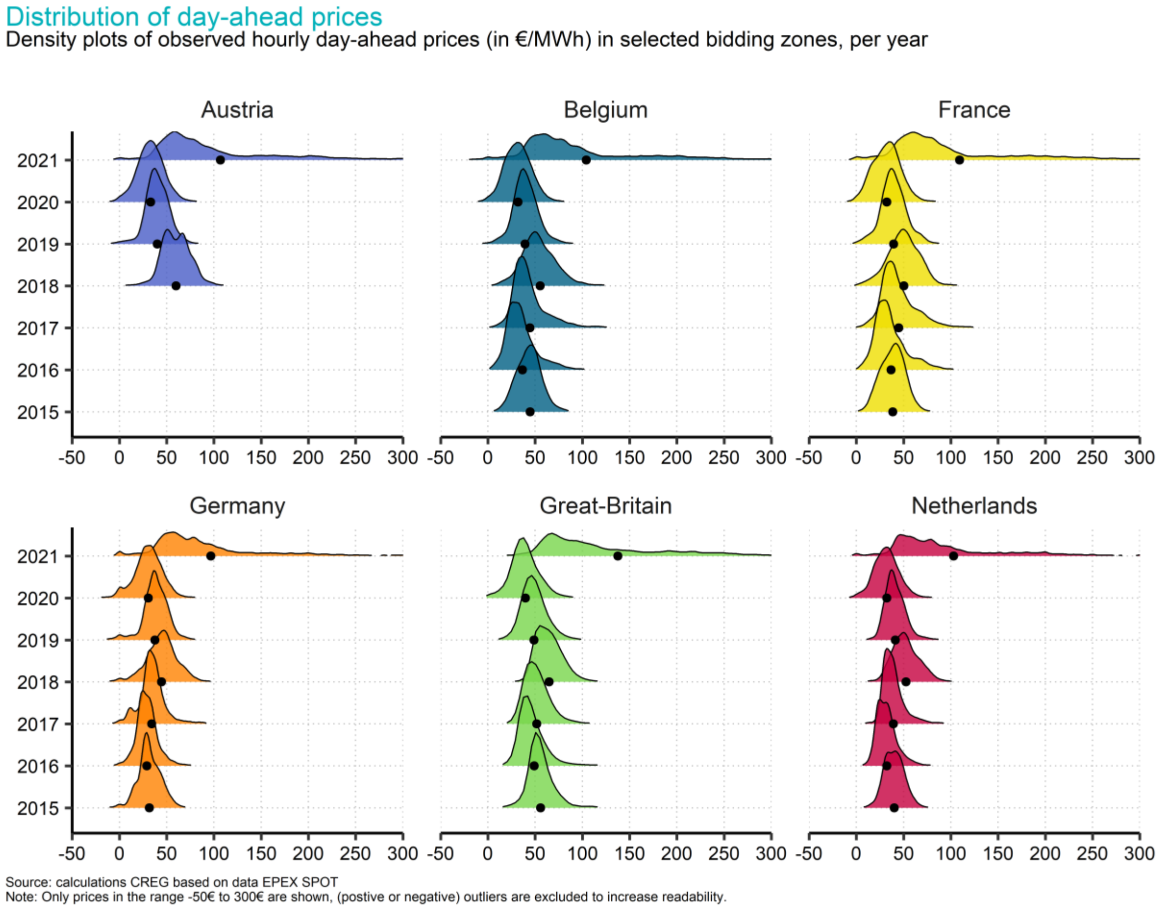


Figure 5-5 Distribution of day-ahead prices

5.2.3. Negative prices

100. Of all of its surrounding countries (and, more generally, of all European bidding zones), Belgium has known most hours with negative prices in 2021. During 159 hours (or 1,8% of the time), day-ahead prices were below zero. Belgium is, also, the only country where this number increased compared to 2020. Somewhat counter-intuitively, this increase in number of hours with negative prices was observed in parallel to the general observation of the extreme price increases in 2021, as explored in the previous section. Figure 5-6 shows, for Belgium and its surrounding bidding zones, the evolution of the number of hours with negative prices between 2015 and 2012.

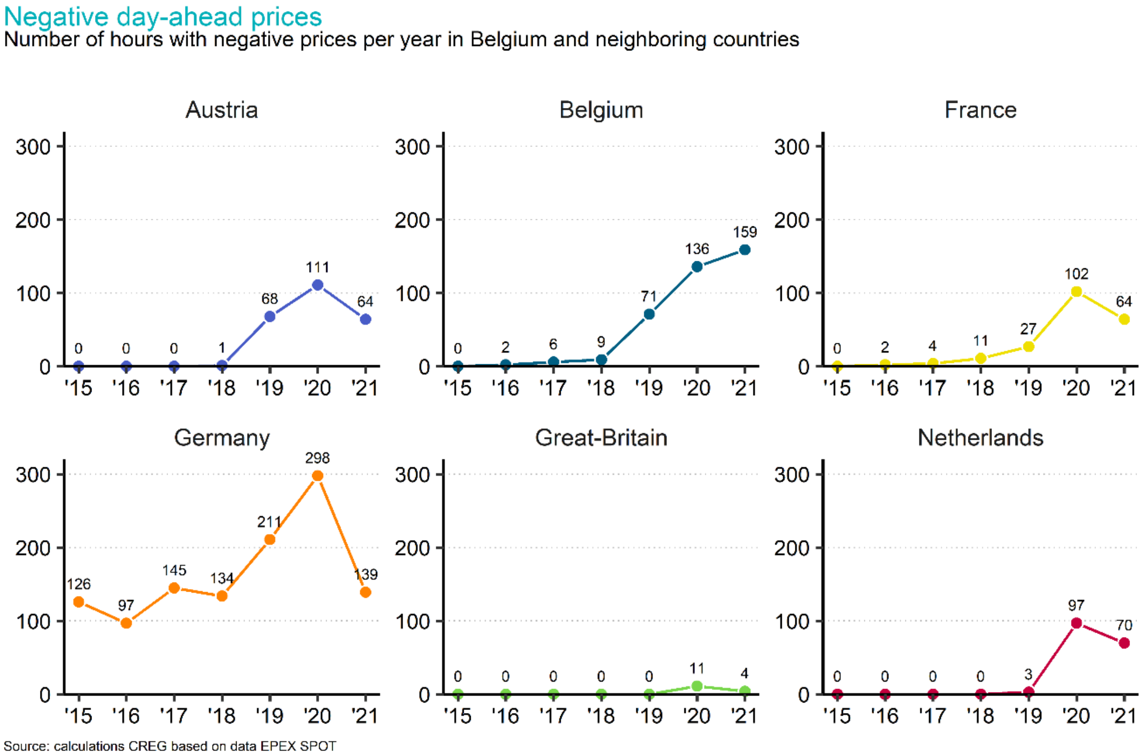


Figure 5-6 Negative day-ahead prices

101. Day-ahead prices become negative as an extreme manifestation of the marginal pricing principle, under circumstances where a bidding zones share of low-cost production capacity (such as wind, solar and nuclear installations) are sufficient to meet the (generally very low) demand in a given hour. Electricity producers bid into the day-ahead market at negative prices, in order to ensure that they are selected by the market coupling algorithm. Depending on the type of production unit, several reasons may apply for bidding at negative prices:

- Electricity producers may have technical constraints preventing them from flexibly lowering their production levels, hence lowering the supply of electricity. This is notably the case for nuclear power plants in Belgium.
- Electricity producers may have sold (significant) shares of their electricity through futures markets and hence are no longer exposed to the negative day-ahead prices – they just lose out on the extra profit of buying electricity at negative prices instead of producing it themselves.
- Electricity producers may benefit from financial support schemes, granted in order to attract investment (mostly into renewable energy sources). Bids may be introduced at negative levels up until the point where they exceed, in absolute value, the profit from the support mechanism.

102. In order to test the validity of these hypotheses, the link between occurrence of negative prices and the output of wind and nuclear power plants (i.e. the main contributing factors) is explored in Figure 5-7. On the y-axis, the share of electricity generated from renewable energy sources (wind on- and offshore as well as solar) and nuclear units, expressed as a percentage of the hourly total load, is shown. The x-as groups all hours according to whether or not negative prices are observed. It is clear that, during hours with negative prices, the share of RES generation is significantly higher (47,7% of total load compared to 18,7% during hours with positive prices). The same holds, yet to a smaller extent, for nuclear generation: during hours with negative prices the share of generation in the total load rises to 65,5% (compared to 57,6% when prices are positive). Generally, during hours with negative prices, the combined generation from renewables and nuclear units amounted to 113,2% of the total load (indicating that excess generation is exported), while this is only 76,3% during hours with positive prices. As there is clearly an excess of generated energy, about 24,0% of the total consumption is exported to neighboring bidding zones, during hours with negative prices.

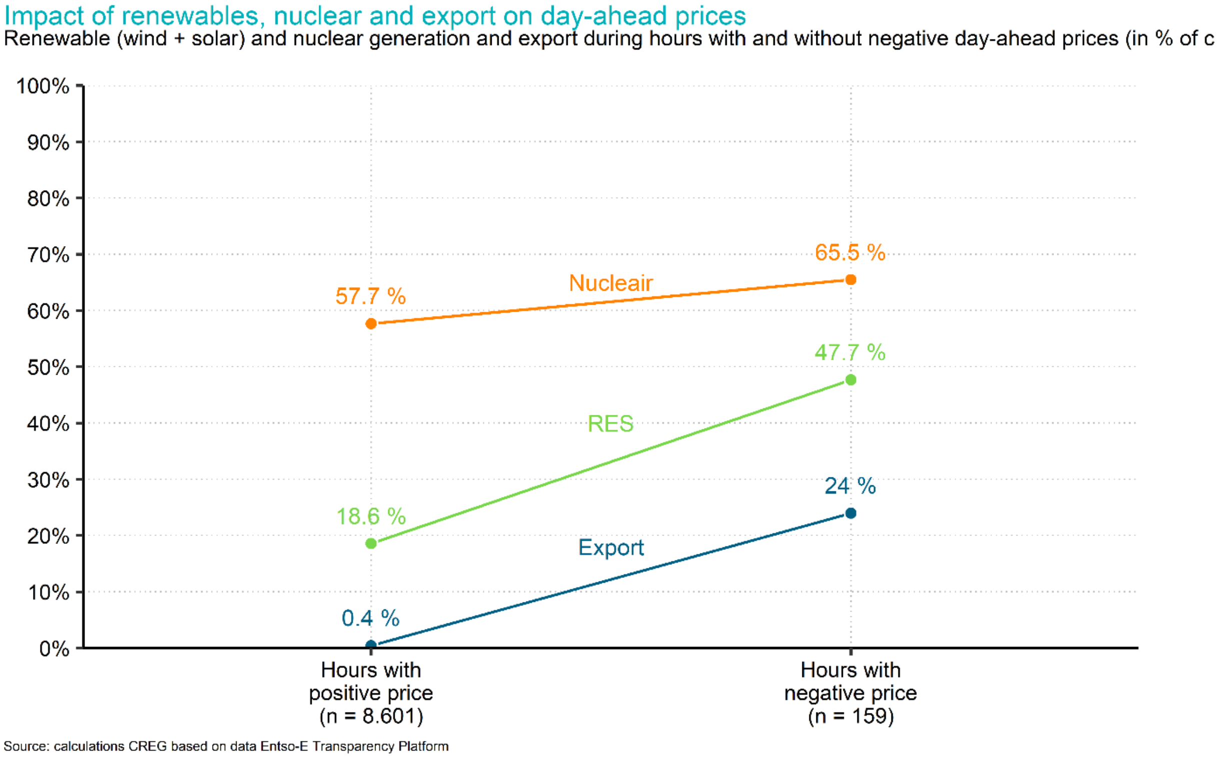


Figure 5-7 Impact of renewables, nuclear and export on day-ahead electricity prices

5.3. PRICE CONVERGENCE AND PRICE SPREADS

103. When the transmission network is capable of accommodating all request for cross-zonal capacity between bidding zones, prices converge because import and export are directing flows from low-priced areas to high-priced areas. This is called price convergence and is used as a measure of market integration.

104. The historical evolution of monthly levels of price convergence (expressed as a percentage of hours in that month) is shown in Figure 5-8. Following the introduction of CWE FBMC in May 2015, the time series show a seasonal cycle with more convergence in summer than in winter. Convergence levels started increasing in 2019 and 2020. This upwards trend was confirmed in 2021, even though price convergence levels decreased to about 30% in the last three months of the year, probably due to low nuclear availability in France (leading to very high export levels from Belgium) and a generally

tense situation in the CWE markets following large relative differences between price levels in those bidding zones.

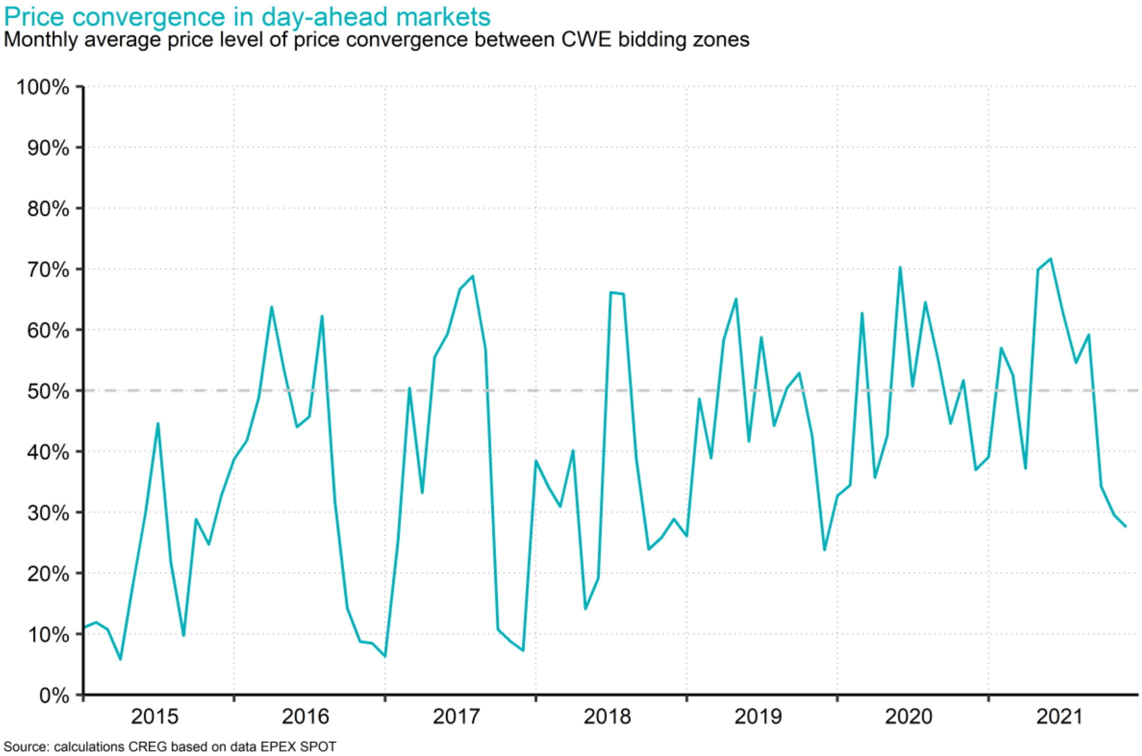


Figure 5-8 Price convergence in day-ahead markets

105. Table 5-5 shows the yearly percentages of hours with price convergence, either between Belgium and one neighboring bidding zones, or with all CWE bidding zones in total. Even though on a bilateral basis, convergence levels dropped since 2020, full CWE compliance was achieved in slightly more hours (49,5% in 2021, compared to 48,5% in 2020). This indicates that, in 2021, price differences on multiple borders at the same time, were more common than in 2020.

	2015	2016	2017	2018	2019	2020	2021
BE = FR	51,0%	63,3%	54,0%	49,5%	60,5%	65,4%	59,9%
BE = NL	52,2%	51,1%	52,7%	51,6%	58,0%	65,5%	58,1%
BE = DE	22,4%	44,0%	41,8%	39,8%	52,8%	58,2%	56,0%
CWE	**20,9%**	**38,5%**	**37,5%**	**35,6%**	**45,9%**	**48,5%**	**49,5%**

Source: calculations CREG based on data Entso-E Transparency Platform

Table 5-5 Yearly full and partial convergence levels

106. When prices do not converge, the difference between the highest and lowest price (defined as the price spread in Figure 5-9) are generally (in 50,0% of all hours[24]) below 5 €/MWh. Even though price spreads occur most often in the range between 5 and 10 €/MWh, higher price spreads are observed as well. At the far right side of the histogram, it may be observed that price spreads exceeding 100 €/MWh occur in 1,2% of all hours between 2015 and 2021 (a total of 793 hours, mostly observed in 2021).

[24] Including 39,5% with full price convergence, not shown in the histogram (price spread is between 0 and 1 €/MWh)

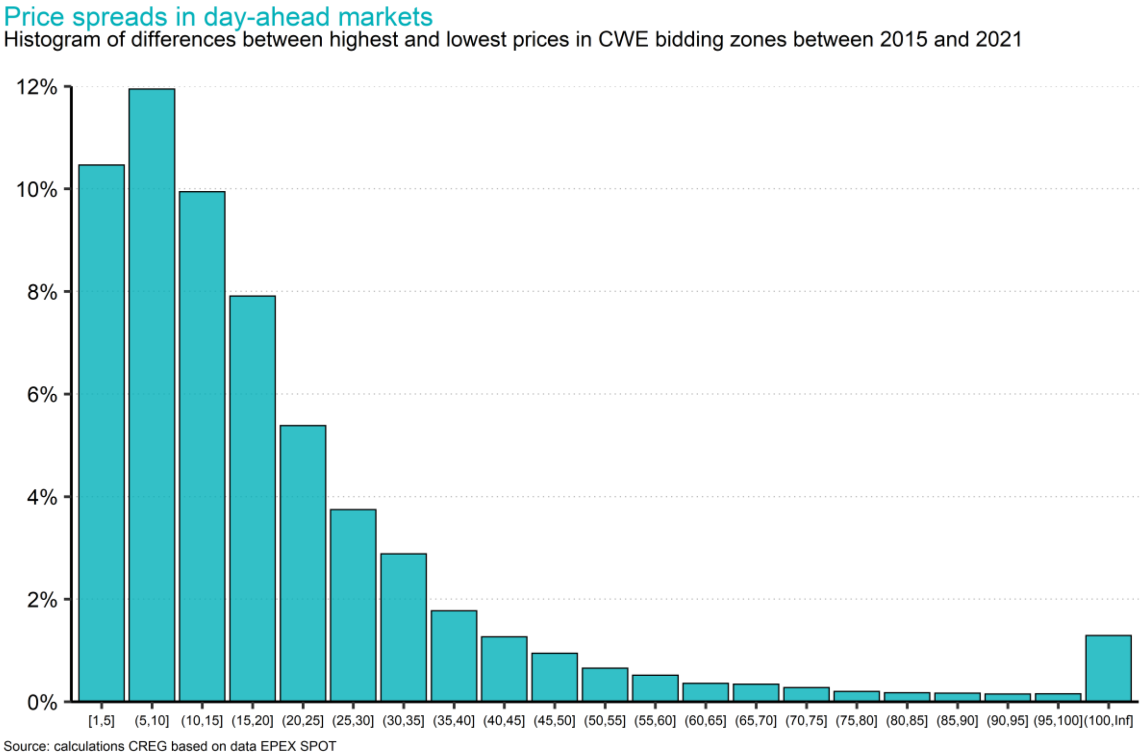


Figure 5-9 Price spreads in day-ahead markets

107. In the CWE FBMC, congestion is caused by the inability of the transmission network to accommodate all cross-zonal trade which is desirable from a welfare-maximization point of view. Technically speaking, there are "active constraints" which limit the market outcome. Figure 5-10 shows the locational distribution of these network elements and their allocation to the responsible TSO. In 2021, Elia had most active CBCOs of all CWE TSOs (2.489), followed by Amprion (1.919). This represents an increase from 2020, when this number was only 1.578.

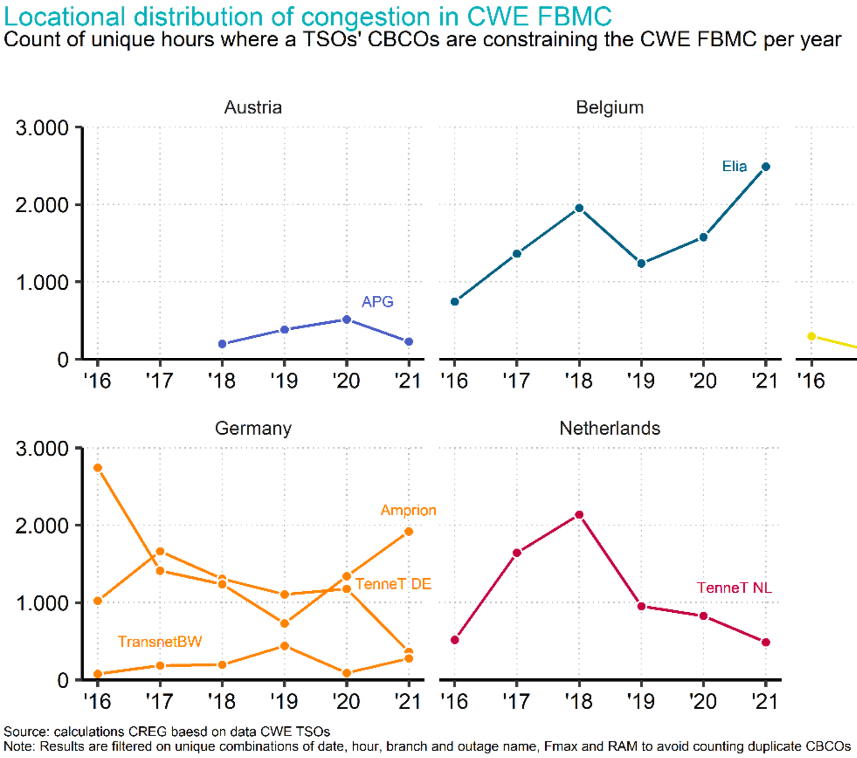


Figure 5-10 Locational distribution of congestion in CWE FBMC

108. The average available margins on the network elements which limit the market outcome (active CBCOs) is shown in Figure 5-11 below. There is a clear difference with regards to the average available margins on active constraints between the TSOs in the CWE FBMC. On its active CBCOs, Elia has offered an average margin of 66,3% throughout 2021.

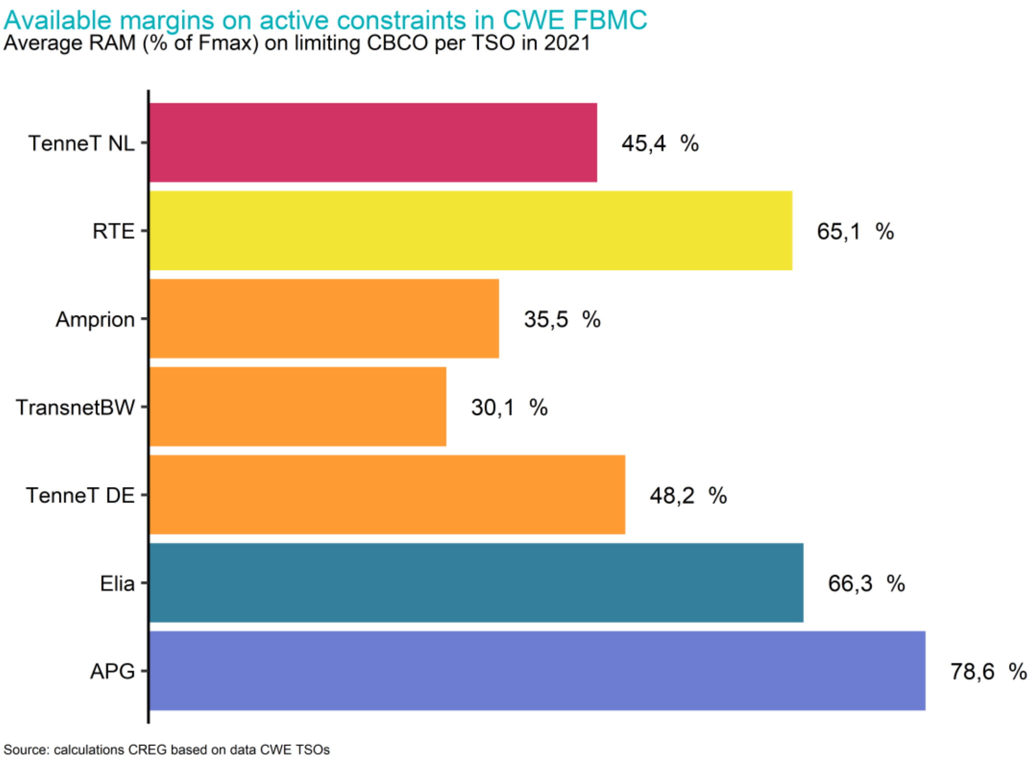


Figure 5-11 Available margins on active constraints in CWE FBMC

5.4. CROSS-BORDER CAPACITIES

5.4.1. Minimum and maximum net positions

109. The maximum export and import positions of a bidding zone in the CWE FBMC framework give an indication of the transmission capacity which is available for cross-zonal trade from the Belgian to other bidding zones. Figure 5-12 shows the average monthly values as well as the monthly ranges (minimum and maximum, i.e. the grey shaded areas). Until mid-2018, the maximum Belgian import was restricted to 4.500 MW through the application of an external constraint, related to maintaining the dynamic voltage stability of the network. This external constraint increased to 5.500 MW for the 2nd half of 2018 and even further to 6.500 from 2019 onwards. Today, the dynamic voltage stability constraint is implemented as an allocation constraint, hence maximum import capacity levels exceeding 7.500 MW (the current value) are reported, even though the *Euphemia* algorithm does not allow that these values are allocated (shown by the red line in Figure 5-12).

110. In 2021, the maximum import positions reached similar levels as in 2020, while they increased strongly in the export direction. On average, the maximum export position in 2021 reached 5.963 MW compared to 5.732 in the import direction: both are all-time high levels since the go-live of the CWE FBMC.

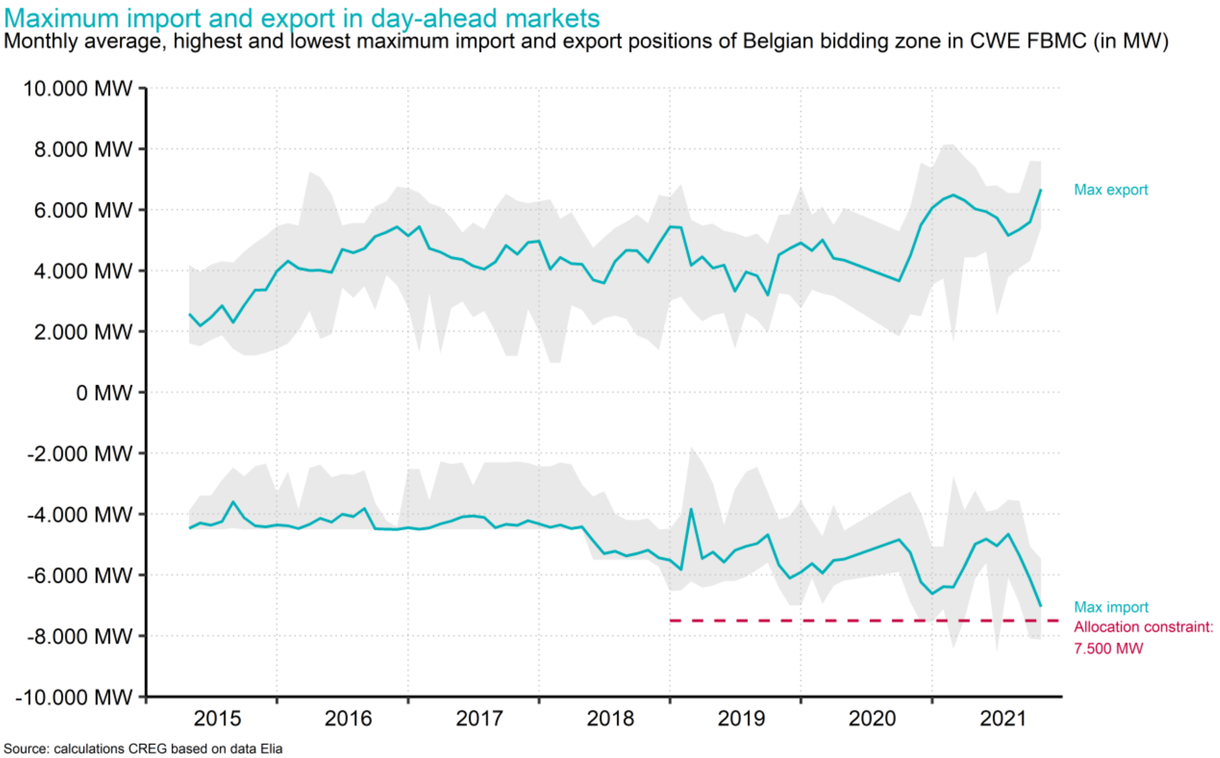


Figure 5-12 Maximum import and export in day-ahead markets

5.4.2. CEP compliance

111. Elia has, just like other European TSOs, a legal obligation (embedded in several legal and regulatory instruments) to maximize the available cross-zonal transmission capacities. In particular, the *Clean Energy Package* (specifically the Electricity Regulation (EU) 2019/943) imposes that at least 70% of the transmission capacity on network elements is offered to the market for cross-zonal exchanges. In 2021, Elia complied with the legal provisions related to the 70% threshold, adjusted for

a derogation for excessive loop flows, during 62,2% of all hours and on 99,2% of all network elements. This is a step back from the compliance, at least when measured in number of hours, from 2020, where 81,3% of all hours were marked as compliant.

112. The calculated results per type of network element (either cross-border, internal or PST) is shown in Table 5-6. A more thorough analyses of the results shown below, including the context under which these margins were observed, has been published by the CREG in the yearly "MACZT compliance reports".[25]

	2020		2021	
	All network elements	Per hour	All network elements	Per hour
Cross-border	99,8%	95,0%	99,7%	90,9%
Internal	98,8%	77,2%	99,0%	50,6%
PST	99,7%	97,0%	99,6%	86,9%
GLOBAL COMPLIANCE	**99,2%**	**81,3%**	**99,2%**	**62,2%**

Source: calculations CREG based on data Elia

Table 5-6 Compliance with minimum margin requirements in the Electricity Regulation

113. The impact of loop flows on network elements, which is a crucial parameter in the calculation of the compliance by Elia with the minimum margin requirements, is explored further in section 5.6. This impact is explained by the derogation which the CREG approved, for the year 2021, from the 70% requirement when specific circumstances linked to excessive loop flows prevent Elia from offering 70% of the capacity on all network elements.

5.5. CONGESTION INCOME

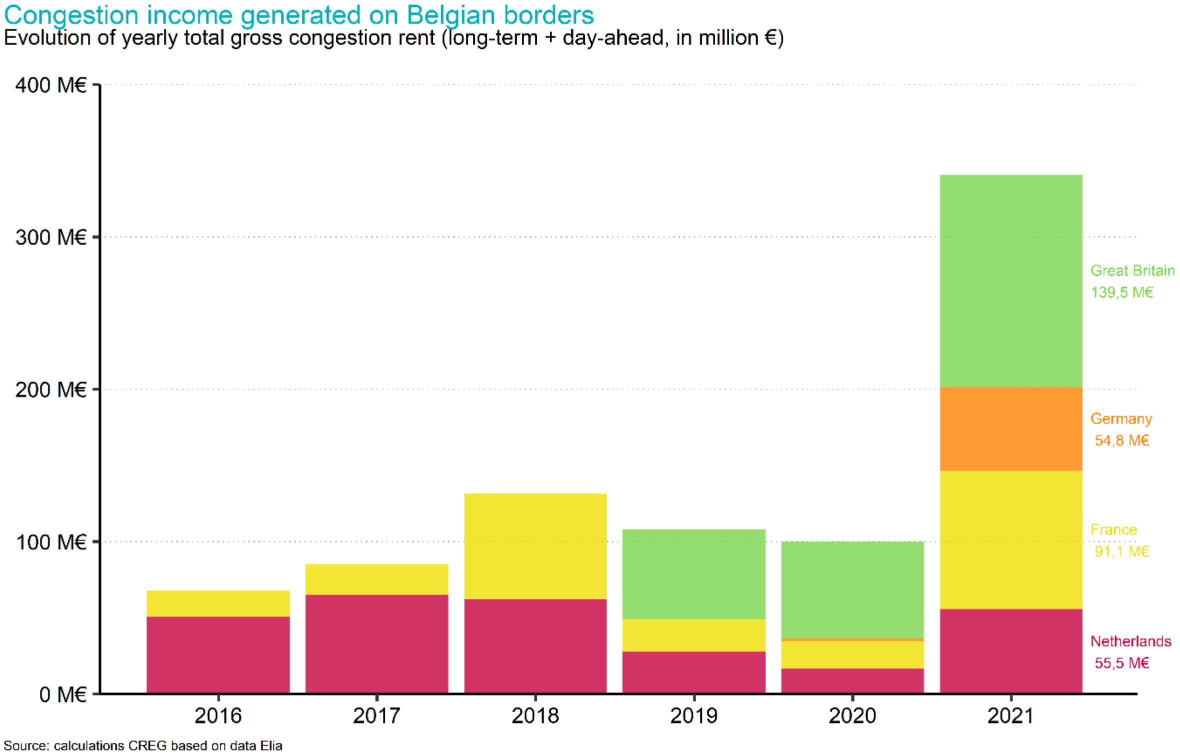
114. When the transmission network is not able to accommodate all requests for cross-zonal capacity in the implicit day-ahead market coupling (due to internal or cross-zonal congestion), price differences can be observed between two bidding zones and congestion income is generated. This congestion income equals the commercial flow (from the relevant timeframe, in this case the day-ahead) multiplied by the price spread.[26]

115. In Belgium, congestion income generated on Belgian orders more than tripled in 2021 compared to 2020, rising from 100,1 M€ (of which 36,5 M€ was generated on Belgium's CWE borders) to 340,8 M€ (with 201,4 M€ on CWE borders). This is remarkable, especially in light of the observation that price convergence (expressed as a fraction of observed hours) remained stable over both years. This implies that, during hours where prices diverged, price spreads increased significantly. This is definitely the case on the border with the bidding zone Great Britain (see also Figure 5-3) but also on CWE

[25] Study (F) 2183 on the compliance of ELIA TRANSMISSION BELGIUM SA with the requirements related to the transmission capacity made available for cross-zonal trade in 2020, *and*
Study (F) 2350 on the compliance of ELIA TRANSMISSION BELGIUM SA with the requirements related to the transmission capacity made available for cross-zonal trade in 2021

[26] Congestion income originates from price differences between bidding zones: it reflects the value of the interconnection capacity and represents an income to TSOs. According to European legislation, it shall be used to invest in additional interconnection capacity or be returned to consumers through a reduction of the transmission tariffs.

borders. The evolution of gross generated congestion income is shown in



116. Figure **5-13**. In other words, even though Elia's performance to further integrate the markets by increasing cross-zonal capacity has been successful if measured from the convergence levels, the cost of non-convergence (and hence the cost of congestion) for producers and consumers have increased.

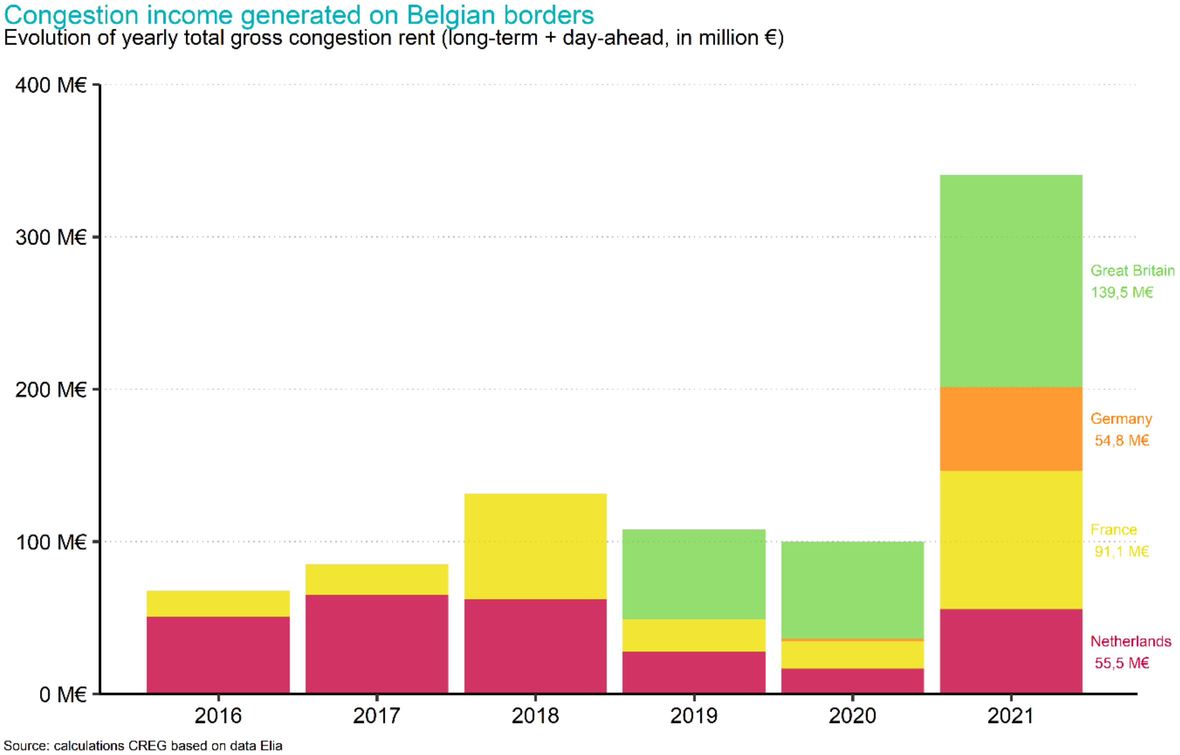


Figure 5-13 Congestion income generated on Belgian borders

117. The gross congestion income generated on CWE borders differs from the net congestion income received by Elia and which are included in the Belgian grid tariffs. These gross congestion income

represents the revenues generated by the day-ahead market coupling on Belgian borders, i.e. before the remuneration of long-term transmission right holders and the sharing of the so-called *"external pot"* between CWE TSOs. The net congestion income is calculated by subtracting these two aspects from the gross income. The comparison between both is shown in Table 5-7: while the sharing of the external pot may have a positive or negative effect, the remuneration of LT TR holders is always negative. This explains the fact that even though gross congestion income for Elia in the CWE region has increased from 36,5 M€ to 201,3 M€, the net income remained relatively stable from 2,9 M€ to 3,3M€ in 2021. A very significant volume of LT TRs needed to be reimbursed at the day-ahead market spread (for an overview of allocated long-term rights, see also section 4.2.

(in M€)	Gross day-ahead congestion income	Net day-ahead congestion income
2016	67,6	8,3
2017	85,2	14,8
2018	131,3	12,8
2019	48,9	7,5
2020	36,5	2,9
2021	201,3	3,3

Source: calculations CREG based on data CWE TSOs

Table 5-7 Difference between gross and net congestion income for Elia on its CWE borders

5.6. LOOP FLOWS

118. Loop flows are observed on network elements within or between bidding zones, yet arise from exchanges within another bidding zone. Hence, they are not within the immediate control of a TSO.[27] Since 2017, Elia publishes the loop flows present in the day-ahead capacity calculation process.

119. In the Belgian transmission network, loop flows historically follow a structural north-to-south direction. They result mostly from exchanges within the German bidding zone, which is relatively speaking much larger than the Belgian bidding zone. In 2021, average monthly loop flows ranged between 204 MW (in May) and 679 MW (in January). This is a consistent decrease from historical levels (observed mostly in 2018 and 2019), both in terms of average as well as in terms of maximum loop flows. Given that loop flows have priority access to the grid and thus-limit cross-zonal trade, the decrease of loop flows is a positive evolution for the CWE FBM (or for the day-ahead cross-zonal exchanges to and from Belgium). The evolution since 2017 is shown in Figure 5-14.

120. The distribution of observed loop flows between 2017 and 2021 confirms this observation about the structural direction in which these flows occur: in a large majority of hours loop flows go from north to south. The evolution of this parameter from 2917 to 2021 is shown Table 5-8. Here it is shown that in 11,3% of all hours of 2021, loop flows went from south to north, or the opposite direction. This factor increased from only 3,2% in 2017.

[27] Even though topological measure, such as the setting of PSTs, exist to *"push back"* loop flows to a certain extent, coordinated between TSOs.

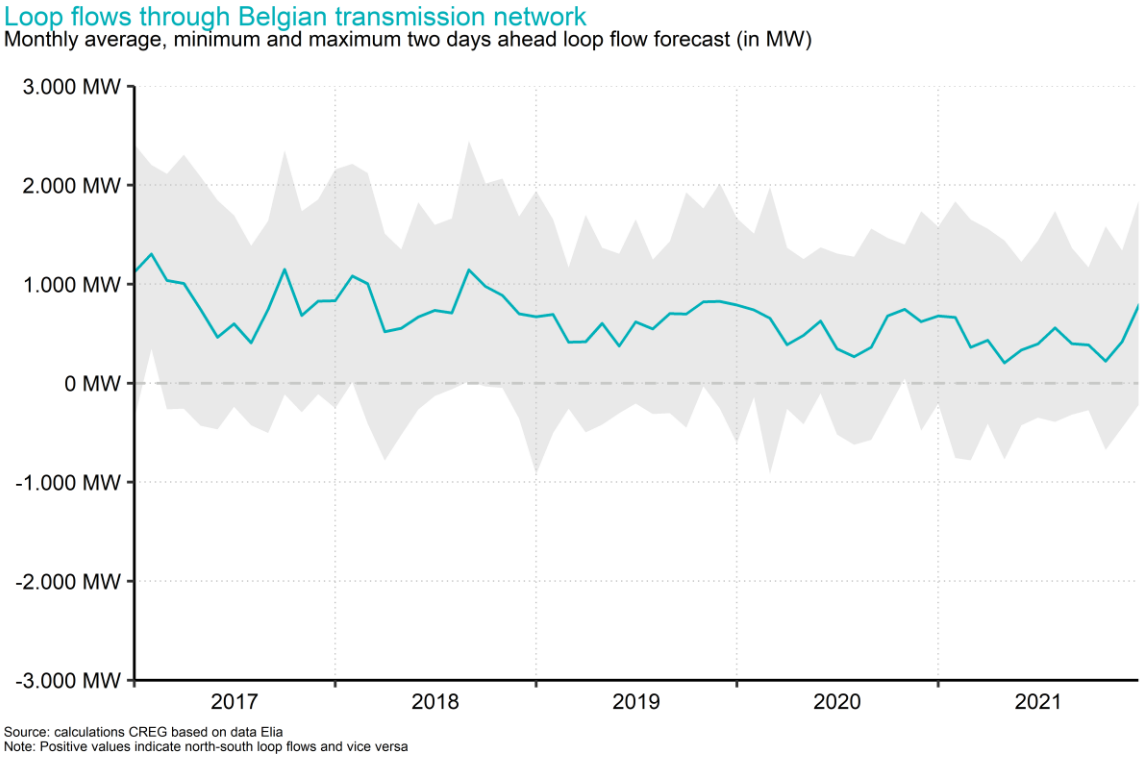


Figure 5-14 Loop flows through Belgian transmission network

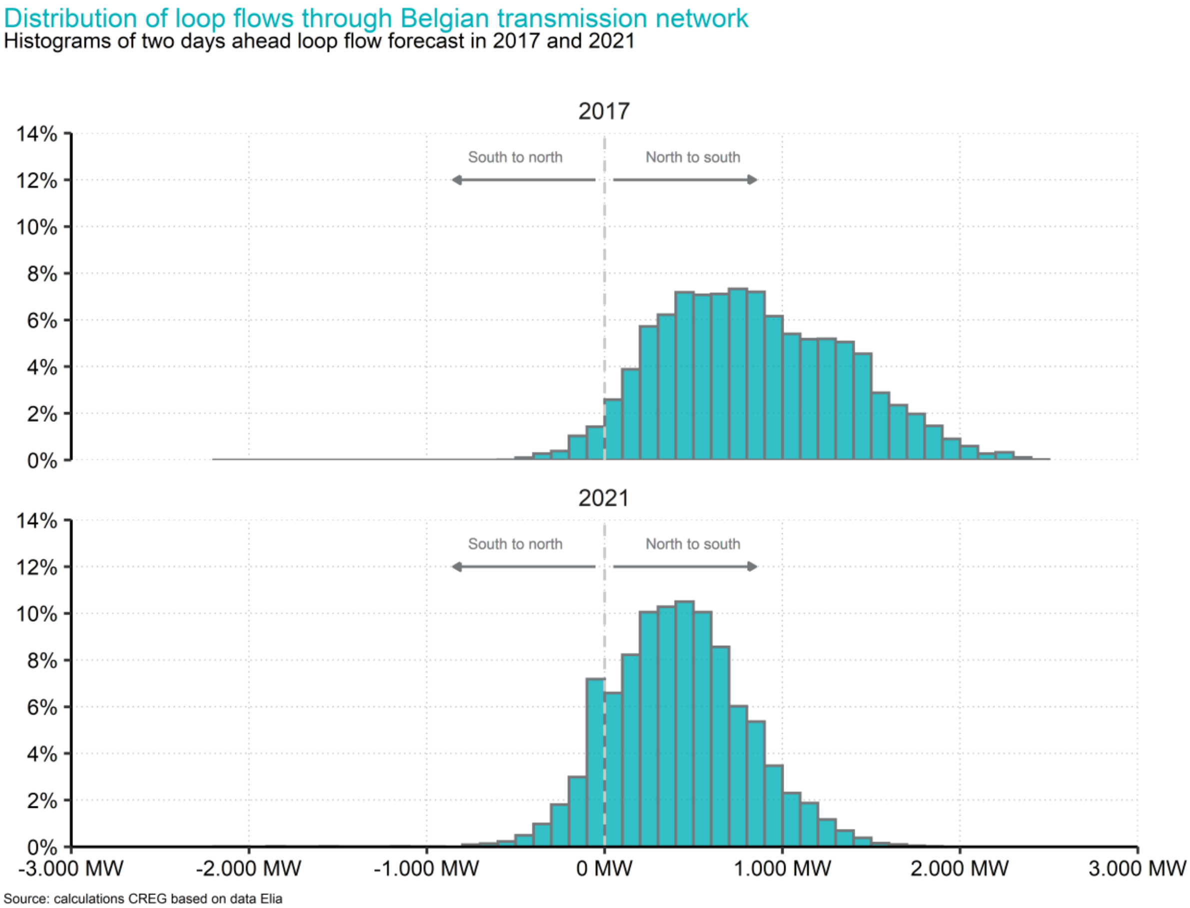


Figure 5-15 Distribution of loop flows through Belgian transmission network

	2017	2018	2019	2020	2021

North to south	96,8%	97,0%	95,7%	94,0%	88,7%
South to north	3,2%	3,0%	4,3%	6,0%	11,3%

Source: calculations CREG based on data Elia

Table 5-8 Percentage of hours with loop flows in a certain direction

6. INTRADAY MARKETS

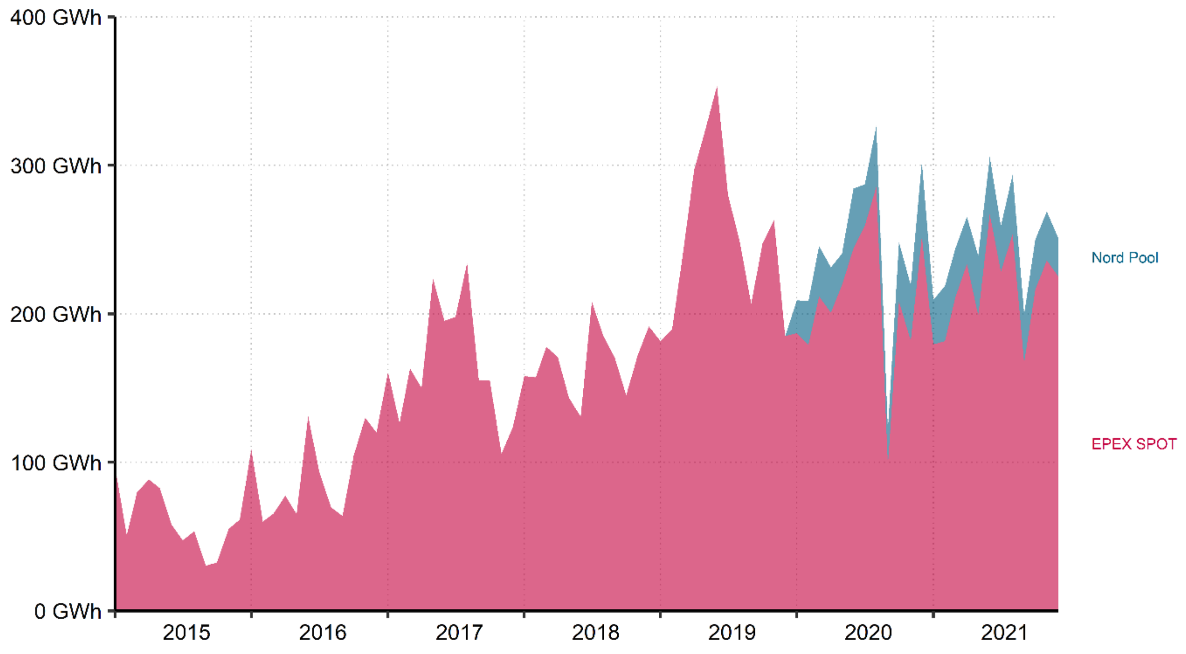
121. Beyond the day-ahead timeframe and before the real time, market participants trade electricity in local or coupled intraday markets. The Belgian continuous, cross-zonal intraday market is coupled in the SIDC (*"Single Intraday Coupling"*) to the markets of 23 other European countries. This continuous market allows for market participants to trade with each other, irrespective of their bidding zone, as long as intraday cross-zonal capacity is available.

122. After the gate closure time of the cross-zonal intraday market, volumes can still be traded on the local intraday markets (organized by either EPEX SPOT or Nord Pool) until 5 minutes before real-time. This chapter focuses on the cross-zonal markets, as these are most liquid and represent the largest share of executed trades. In the following sections, the volumes, reference prices and available cross-zonal capacities are presented.

6.1. EXCHANGED VOLUMES

123. The traded volumes in the Belgian cross-border intraday markets, operated by Nord Pool and EPEX SPOT (coupled withing XBID) increased slightly from 2020 to 2021, from 2,9 TWh to 3,0 TWh. Compared to the day-ahead traded volumes (23,4 TWh, see also section 5.1) this volume represented only 12,8%.

Exchanged volumes in intraday markets
Monthly total exchanged volumes in Belgium for EPEX SPOT and Nord Pool (in GWh)



Source: calculations CREG based on data EPEX SPOT and Nord Pool
Note: Exchanged volume equals the highest of the buy and sell volumes per NEMO

Figure 6-1 Exchanged volumes in intraday markets

124. As in the day-ahead market, the market shares of the incumbent EPEX SPOT remains much higher since the go-live of the multi-NEMO arrangements in the CWE region in 2021: 86,5% against only 13,5% for the new entrant, Nord Pool. This number has remained stable between 2020 and 2021.

(in GWh)	2015	2016	2017	2018	2019	2020	2021
EPEX SPOT	737,8	1090,7	1992,1	2011,3	3015,4	2527,4	2598,9
Nord Pool	0,0	0,0	0,0	0,0	0,0	398,2	406,6

Source: calculations CREG based on data EPEX SPOT and Nord Pool

Table 6-1 Exchanged volumes in intraday markets

125. The number of trades performed through the XBID platform steadily increased since its go-live on 12 June 2018. On average, the quarter-to-quarter increase of the matched trades reached 13,7% with numbers as high as 28,6% (from Q3 to Q4 2019). This maximum increase coincides with the launch of the 2nd wave of XBID in November 2019, when 7 Central and Eastern European countries joined the SIDC. The only recorded decrease took place between Q2 and Q3 2019.

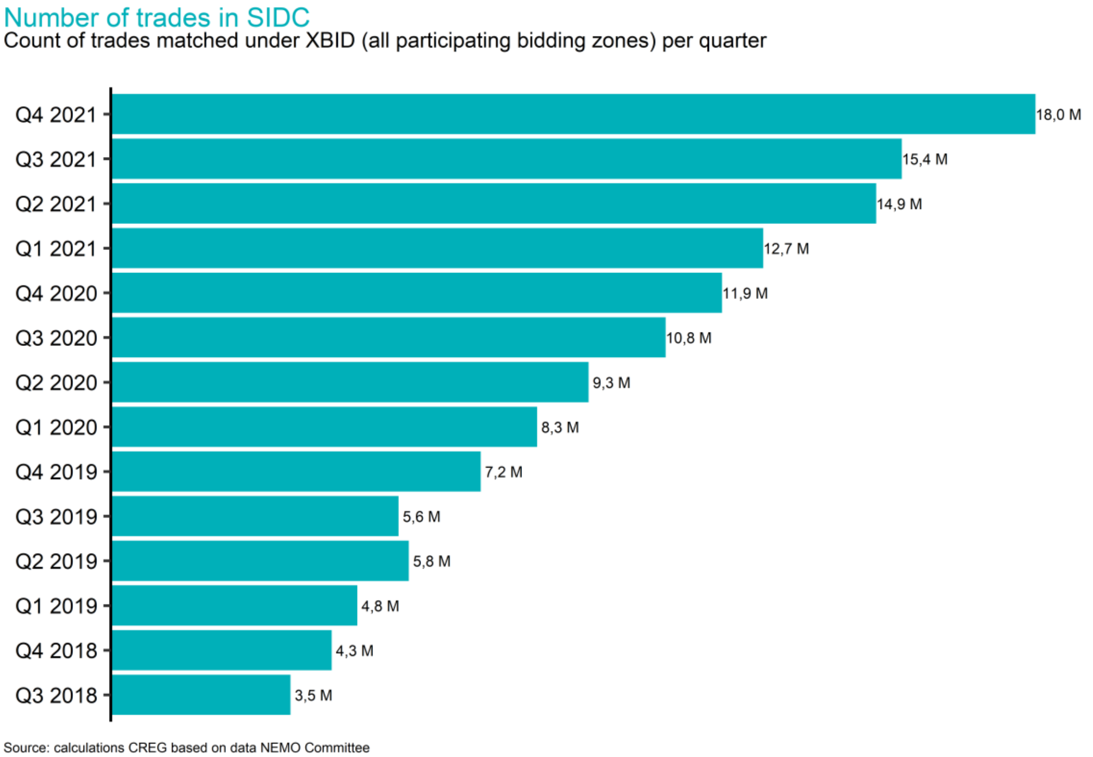


Figure 6-2 Number of trades in SIDC

6.2. PRICES

126. The average intraday reference prices[28] have increased significantly in 2021 compared to the previous years, despite a strong – yet temporary – decrease in 2020. The annual average prices in the intraday timeframe are closely aligned to the day-ahead market, as shown in Table 3-1.

Reference prices (€ / MWh)	2015	2016	2017	2018	2019	2020	2021
Intraday	44,0	37,9	45,7	56,3	40,2	31,2	103,9
Day-ahead	44,7	36,6	44,6	55,3	39,4	31,9	104,1

Source: calculations CREG based on data EPEX SPOT

Table 6-2 Reference price in the intraday versus the day-ahead timeframe

127. While the yearly average prices, as shown in Table 6-2, rarely deviate more than 1 €/MWh between the day-ahead and intraday timeframe, the differential between the two metrics is much larger with an hourly granularity. Between 2016 and 2019, the difference between the intraday and day-ahead prices were between -20 and 20 €/MWh in around 80% of all the hours of the year. This started changing in 2020 but more abruptly in 2021: last year, only about 40% of the hours has seen price differentials in the same -20 to 20 €/MWh range. Figure 6-3 shows the yearly histograms with the observations (insofar as they fall within the -100 to 100 €/MWh range).

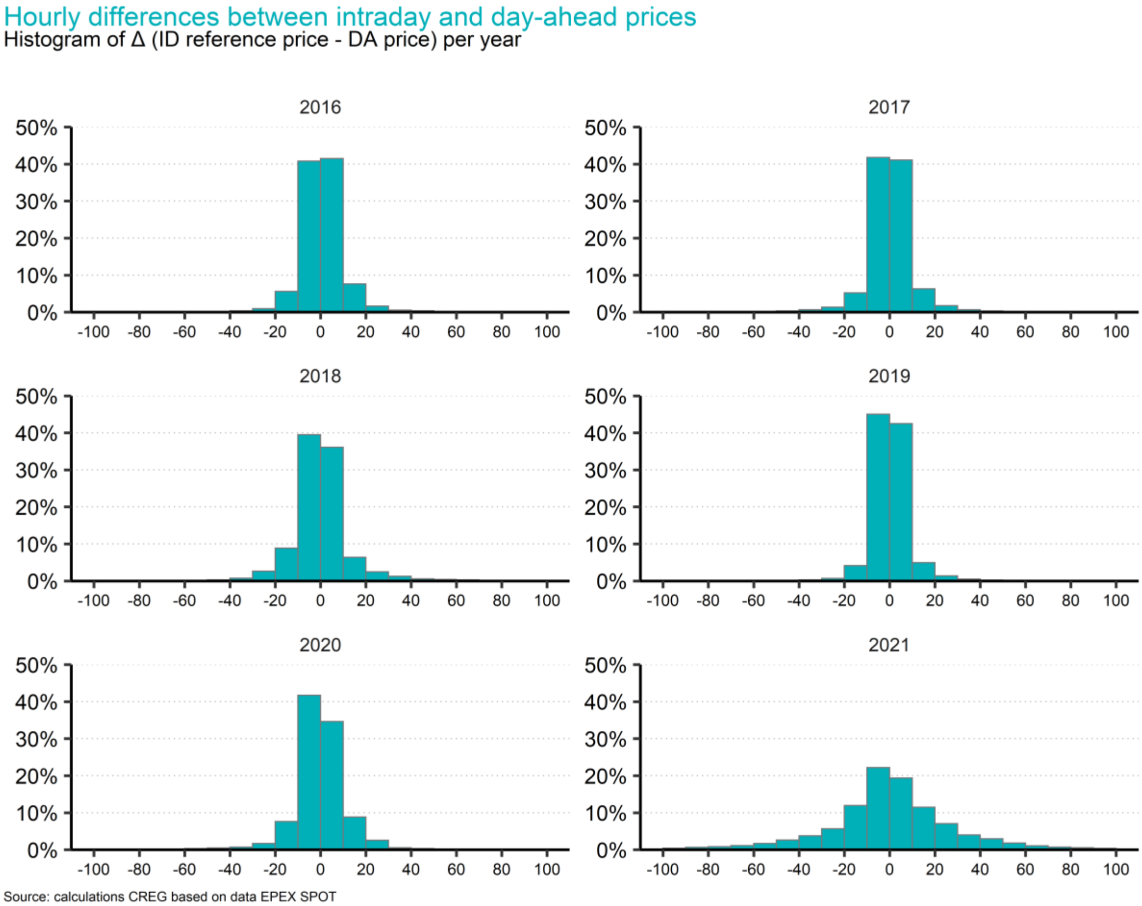


Figure 6-3 Hourly differences between intraday and day-ahead prices

[28] The intraday reference price is calculated as a volume-weighted average of the matched trades on the Belgian EPEX SPOT market.

128. Minimum values for the intraday reference prices have gone below -100 €/MWh for the first time since 2019. As in the day-ahead timeframe, negative prices occur increasingly as well. In 2021, these negative prices have been seen in 293 hours, a (slight) decrease since the previous year (305 in 2020). The maximum observed reference price in the intraday markets reached 604,2 €/MWh in 2021.

Reference prices (€ / MWh)	2015	2016	2017	2018	2019	2020	2021
Min	-9,3	-90,0	-44,1	-51,0	-150,0	-127,2	-184,4
Max	420,0	572,9	426,6	590,0	276,5	612,2	604,2

Source: calculations CREG based on data EPEX SPOT

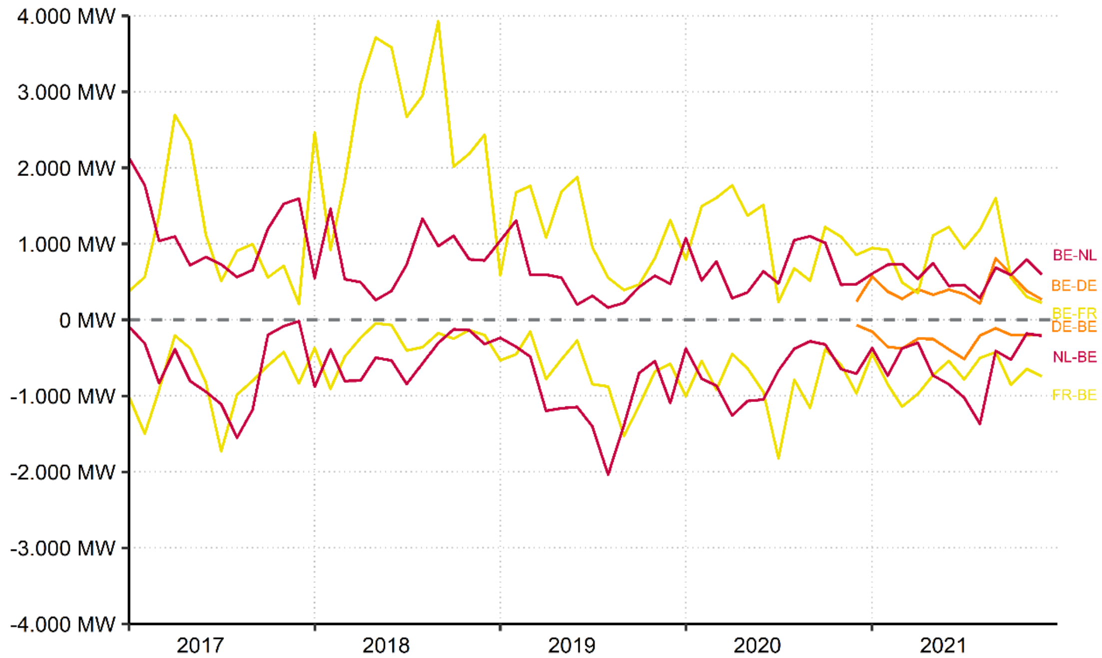
Table 6-3 Minimum and maximum intraday reference prices

6.3. CROSS-BORDER CAPACITIES

129. In the intraday timeframe, Elia and the other European TSOs make capacity available for cross-zonal trade. Today, the capacity calculation is performed in the framework of the CWE region, meaning that there is a coordination between Elia and the TSOs of the Dutch, French, German and Austrian bidding zones.

130. Initially, at the opening of the intraday cross-zonal market, the *leftover* capacity from the day-ahead timeframe is given to the market. This is done by extracting the bilateral trade possibilities (a so-called ATC-extraction) from the day-ahead flow-based domain corrected of the day-ahead allocated capacities. In a second step, after the initial ATC computation, TSOs have the possibility to re-assess the new capacities, leading to *"increase"* or *"decrease"* requests. The results of this process, i.e. the bilateral ATCs on the coupled borders, are shown in Figure 6-4.

Average intraday import and export capacities
Evolution of monthly average import and export ATCs (DA leftover + accepted increase/decrease requests) (in MW)



Source: calculations CREG based on data CWE TSOs

Figure 6-4 Average intraday import and export capacities

131. Relatively high average capacity values appear in the time series: for example during 2018 from Belgium to France, or in the first half of 2019 from the Netherlands to Belgium. These could be explained by the fact that often these capacities are against the market direction (against the day-ahead price differential): used capacity in one direction (in the day-ahead timeframe) is then netted in the other direction for the intraday timeframe.[29]

132. Despite the relatively high ATC values in the analyses above, the extraction of the left-over domains after the day-ahead market coupling often results in zero ATC values, meaning that no capacity is available on a certain border for cross-zonal intraday trades. Hence, without the increase / decrease process, no cross-zonal exchanges would be possible during about 40% of the hours in 2021 (see Figure 6-5).

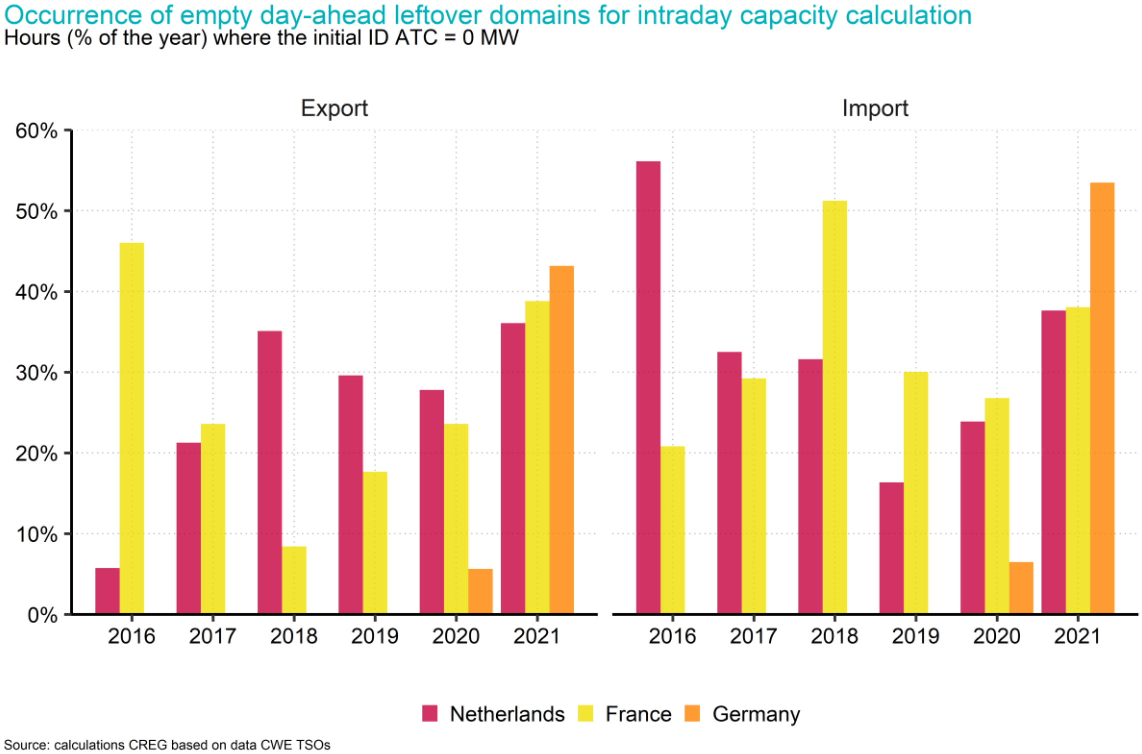


Figure 6-5 Occurrence of empty day-ahead leftover domains for intraday capacity calculation

133. After the extraction of the day-ahead leftover initial intraday ATC values, TSOs have the possibility to re-assess the new capacities, leading to *"increase"* or *"decrease"* requests. The occurrence of such accepted requests (in % of observed hours per year) is shown in Table 6-4 below. These summary statistics show that, since 2017, the number of (accepted) increase requests on the northern and southern borders have decreased steadily, with (slight) improvements in 2020 (except BE-NL). It is also worth noting that decrease requests are only applied on the ALEGrO interconnector (the BE-DE and DE-BE borders).

[29] Through the principle of netting, capacity allocated to one trade (or a set of trades, as the outcome of the day-ahead market coupling process) is deducted from the available capacity in that direction and added to the capacity in the opposite direction.

	INCREASE						DECREASE					
	BE-NL	BE-FR	BE-DE	NL-BE	FR-BE	DE-BE	BE-NL	BE-FR	BE-DE	NL-BE	FR-BE	DE-BE
2017	21,9%	42,8%		16,4%	22,0%		0,0%	0,0%		0,0%	0,0%	
2018	16,8%	18,0%		14,7%	13,0%		0,0%	0,0%		0,0%	0,0%	
2019	6,4%	8,5%		5,4%	11,8%		0,0%	0,0%		0,0%	0,0%	
2020	4,2%	8,9%	0,0%	12,3%	17,3%	0,0%	0,0%	0,0%	21,5%	0,0%	0,0%	12,4%
2021	7,7%	8,6%	22,2%	4,7%	11,4%	18,6%	0,0%	0,0%	7,5%	0,0%	0,0%	3,1%

Source: calculations CREG based on data Elia

Table 6-4 Yearly percentage of hours with accepted increase/decrease request per border

134. In addition, Table 6-5 shows – for hours where accepted increase/decrease requests are found – the average volumes. These are, on most borders, between 200 and 300 MW, except when they are downward (i.e. decrease requests) on the ALEGrO interconnector.

	INCREASE						DECREASE					
	BE-NL	BE-FR	BE-DE	NL-BE	FR-BE	DE-BE	BE-NL	BE-FR	BE-DE	NL-BE	FR-BE	DE-BE
2017	217	215		221	216							
2018	217	230		211	225							
2019	249	267		253	256							
2020	218	257		266	256				-560			-386
2021	244	251	232	252	249	232			-516			-364

Source: calculations CREG based on data Elia

Table 6-5 Yearly average volume of the accepted increase/decrease requests per border

7. BALANCING MARKETS

135. This chapter summarizes the developments on the Belgian balancing (capacity and energy) markets. In a first section, the procurement of balancing capacity through different product types is described. Secondly, the activations of these capacities is discussed and in a final section, the imbalances (on a system- and individual level) and imbalance prices are described.

7.1. BALANCING CAPACITY

136. During the last years, measures have been taken to reduce barriers to entering the balancing capacity market in Belgium. After a steep increase in aFRR and mFRR procurement costs observed in 2018 (especially caused by overall higher prices in the electricity markets in the last quarter of the year due adequacy concerns), cost have decreased in subsequent years. However, the total procurement cost of balancing capacity in 2021 steeply increased in 2021 to 182,4 M€; this is 147% of the total cost in 2018 and 234% of the cost observed in 2020. The steep increase is attributed to the increase of the gas price, especially since the outbreak of the war in Ukraine.

Total capacity cost (M€)	2015	2016	2017	2018	2019	2020	2021
FCR	22,1	11,7	10,3	9,6	6,7	7,1	24,2
aFRR	28,8	33,5	34,7	43,3	25,7	27,1	121,0
mFRR	18,9	21,5	23,9	71,1	48,5	43,7	37,2
Total	69,8	66,7	69,1	124,0	80,8	78,0	182,4

Source: calculations CREG based on data Elia

Table 7-1 Procurement costs for each of the balancing reserve types procured in the LFC Area of Elia

7.1.1. FCR capacity

137. The full opening of the FCR market to new market entrants already occurred in 2016 after some design changes that reduced substantial entry barriers (by shortening contracting periods and facilitating cross-border procurement). This lead to a decrease in the procurement costs for FCR capacity mainly due to a decreasing average procurement cost per MW/h. The most recent changes in the design of FCR procurement include:

- As of July 2019, the procurement of FCR capacity in the FCR Cooperation was organized via daily auctions. About 70% of the total Belgian demand for FCR capacity was procured in the FCR Cooperation while the remaining capacity was still procured locally in weekly auctions.
- As of 1 July 2020, the total Belgian demand for FCR capacity was completely procured in the FCR Cooperation based on 4-hour blocks to enable the participation of new entrants.

138. The year 2021 is the first full year of procuring FCR completely on the FCR Cooperation. Evolutions in 2021 caused the FCR procurement costs to increase significantly. While no units dependent on natural gas are structurally providing the FCR-service, opportunity costs set by gas-fired power plants in subsequent markets (e.g. the aFRR and/or day-ahead market) have pushed up the FCR market prices for delivery in Belgium.

FCR capacity	2015	2016	2017	2018	2019	2020	2021
Need (MW)	83	68	68	81	81	78	87
Average cost (€/MW/h)	30,5	18,3	17,0	14,7	9,2	9,0 (i) 16,6 (ii)	31,7

(i) Average FCR capacity price until June 2020 (procurement via local and regional platform)
(ii) Average FCR capacity price as of July 2020 (FCR entirely procured via the regional platform)
Source: calculations CREG based on data Elia

Table 7-2 Capacity needs and procurement costs for FCR capacity procured in the LFC Area of Elia

7.1.2. aFRR capacity

139. Substantial changes in the procurement of aFRR capacity were implemented at the end of September 2020. Since then the aFRR capacity for the contracting periods of day D is procured in two short-term auctions: one organized on day D - 2 and one on day D - 1. These changes aim to attract new types of flexibility providing the aFRR service to increase the competitiveness of the aFRR market. In the long run such changes also support the evolution towards a climate-neutral market. The aFRR capacity to be procured has, however, remained fixed at 145 MW. Unlike for mFRR capacity, there is no daily dimensioning of aFRR capacity needs yet.

140. The total aFRR capacity costs have been decreasing since 2018. Similarly as for FCR, total costs increased significantly in 2021 due to the increase in gas prices and the high reliance on gas-fired power plants to deliver the aFRR service. The design change of the aFRR capacity market mentioned above attracted volumes from balancing resources not dependent on natural gas, however the volumes are insufficiently large to offset gas dependency.

141. In 2021, an update of the aFRR balancing capacity market design was concluded in cooperation with market participants. The update was needed because of an inefficient allocation of volumes between the symmetric daily product and the asymmetric 4-hour products. The new design is planned to enter into force in April 2022.The detailed analysis regarding the different prices between the different products and between the different directions will be conducted in a next version of the monitoring report. Preliminary results show that aFRR balancing capacity prices for asymmetric products are generally lower, and that prices for negative capacity are lower than for positive capacity.

aFRR capacity	2015	2016	2017	2018	2019	2020	2021
Need (MW)	140	140	142	139	145	145	145
Average cost symmetric product (€/MW/h)	23,5	27,3	28,0	35,5	19,9	16,7 (i) 34,5 (ii)	95,3

(i) Average aFRR capacity price before the introduction of daily procurement.
(ii) Average aFRR capacity price after the introduction of daily procurement.
Source: calculations CREG based on data Elia

Table 7-3 Capacity needs and procurement costs for aFRR capacity procured in the LFC Area of Elia

7.1.3. mFRR capacity

142. Several changes in the opening of the mFRR capacity market occurred with the latest main change in February 2020: since then, mFRR capacity is no longer procured on a monthly basis but on a daily basis. Each day at 10:00, an auction is organized for each of the 6 contracting periods of 4 hours

[30] The average cost for a symmetric product is

of the next day. The volume to be procured is determined based on daily dimensioning, including rules on minimum share of mFRR Standard capacity. The minimum volume of mFRR Standard capacity[31] in 2021 remained at 640 MW, as it was from July 1st 2020 onward.

mFRR capacity	2015	2016	2017	2018	2019	2020	2021
Need (MW)	661	770	780	830	844	844 (i) 840 (ii)	857 643(*)
Average cost (€/MW/h)	3,2	3,6	3,4	9,9	6,6	4,9 (i) 6,0 (ii)	6,6

(i) Before the introduction of daily procurement (fixed value for the mFRR need)
(ii) After the introduction of daily dimensioning and daily procurement of mFRR capacity
Source: calculations CREG based on data Elia
(*) As of 6 January 2021 the mFRR capacity procured for the next day decreased substantially due to an increased share of inter-TSO reserves considered in the dimensioning.

Table 7-4 Capacity needs and procurement costs for mFRR capacity procured in the LFC Area of Elia

7.2. BALANCING ENERGY

143. If BRPs as an aggregate fail to be in balance, a system imbalance is observed by Elia. The system imbalance must be compensated with FRR balancing energy within 15 minutes. In order to achieve this objective, multiple resources are activated.

144. The first resource activated is imbalance netting. LFC Blocks with a positive system imbalance exchange their oversupply towards LFC Blocks with negative system imbalance. Such exchange lowers the system imbalance in both LFC Blocks in real time as long as interconnection capacity is available. The second resource activated is aFRR which reacts automatically based on the remaining area control error and is fully activated within 7,5 minutes. Both imbalance netting as the activation of aFRR balancing energy is remunerated on 4 second basis because of their real-time and near-real-time contribution to the compensation of the system imbalance. The third resource activated is mFRR which reacts at the request of Elia and is used to desaturate the aFRR balancing energy in case of long lasting area control errors. Besides reserve sharing with other TSOs as another resource to active balancing energy from abroad to compensate system imbalances in Belgium, other, more exceptional procedures exist, such as the activation of slow starting units, to contribute to the compensation of the system imbalance.

145. The use of balancing resources to compensate system imbalances attained 1,2 TWh in 2021. Compared with an estimated Belgian consumption of 84,4 TWh in 2021, compensating the system imbalance accounts for 1,4% of the energy consumed. In 2021, 42,0% of the balancing needs are compensated by imbalance netting. This share has decreased slightly with respect to 2020 (43,9%).

The use of imbalance netting and aFRR to compensate negative system imbalances has increased with respect to 2020 (+18,4%). The use of imbalance netting and aFRR to compensate positive system imbalances has decreased again year over year in 2021 (-11,0%) and in 2019 (-5,2%).

The use of positive mFRR increased with 47,8% year over year in 2021. The use of mFRR is volatile: the year-over-year change was +36,1% in 2020 and -14,0% in 2019.

Reserve sharing was used in 2021: 400 MWh was activated in the positive direction, and 1350 MWh in the negative direction.

[31] Assuming the total mFRR capacity to be procured is larger.

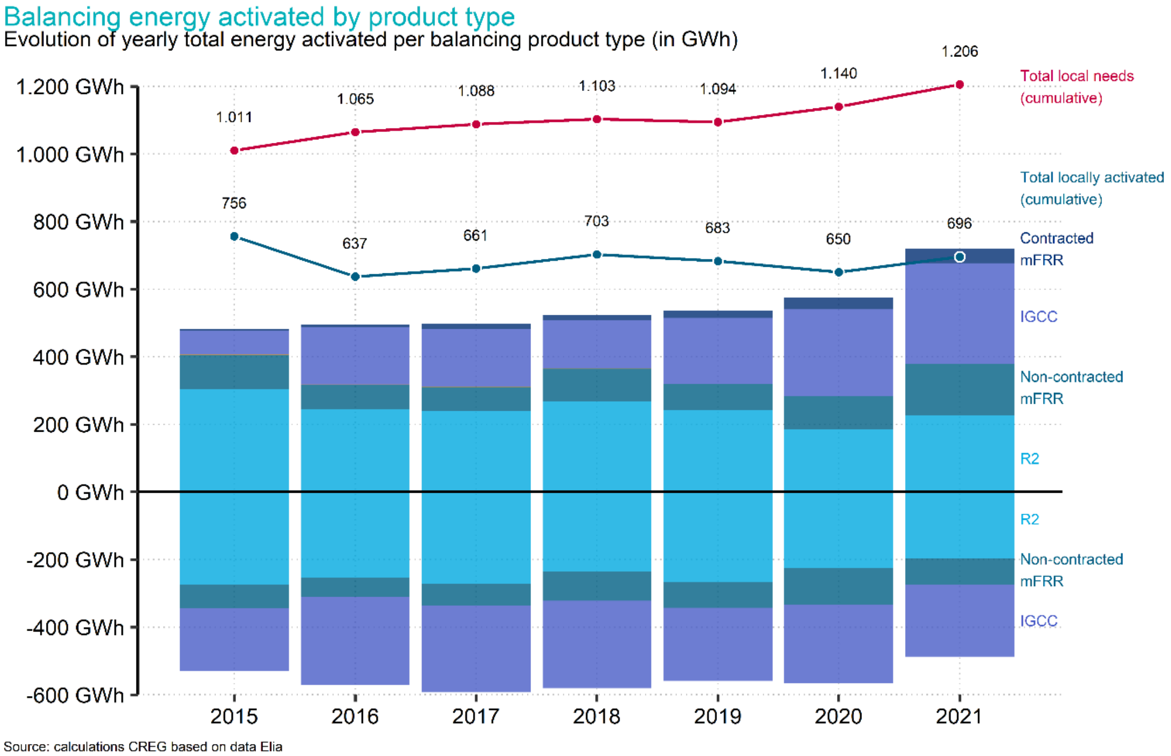


Figure 7-1 Balancing energy activated per product type

7.3. IMBALANCES

146. Each Balance Responsible Party ("BRP") is required to contribute to a balanced power system, either by maintaining a balanced portfolio or by holding an imbalanced position in the direction that helps the power system as a whole. Each BRP's imbalance is settled at the imbalance price. Table 7-5 shows the financial flows of BRP settlement, depending on the sign of the imbalance prices (columns, horizontally) and the imbalance in the perimeter of the BRP (rows, vertically).

	Imbalance price positive	Imbalance price negative
Positive imbalance	Payment from TSO to BRP	Payment from BRP to TSO
Negative imbalance	Payment from BRP to TSO	Payment from TSO to BRP

Source: Regulation (EU) 2017/2195 (Electricity Balancing Guidelines), article 55

Table 7-5 Flow of payments of imbalance prices

147. BRP imbalance settlement is based on a single marginal pricing method. Per quarter-hour, the imbalance price reflects the marginal price paid for activating balancing energy (via imbalance netting, aFRR or mFRR) in the direction most required based on the net system imbalance, adjusted with an alpha component. The imbalance price creates an opportunity cost for the BRPs aggravating the system imbalance and an opportunity profit for those BRPs helping the system be balanced.

148. Assuming positive imbalance prices, when the system is short, a BRP with a positive imbalance receives the marginal price for upward regulation ("MIP") plus the alpha component. A BRP with a negative imbalance must pay the same imbalance price.

149. When the system is long, a BRP with a positive imbalance receives the marginal price for downward regulation ("MDP") minus the alpha component. A BRP with a negative imbalance must pay the same imbalance price.

150. At the start of 2020 a new imbalance tariff methodology was introduced, changing the composition of the imbalance price compared to the previous tariff period. The determination of the alpha component was modified in order to provide quicker and larger incentives for the BRPs to take actions in favor of the system. The alpha component obtains a value larger than zero if the system imbalance for the quarter-hour is larger than 150 MW (in positive or negative direction).

7.3.1. System imbalance

151. The distribution of the system imbalance follows a similar pattern each year, as shown in Figure 7-2, however a shift towards increasingly negative system imbalances is visible. In 2016-2017 42-44% of the quarter-hours measured a negative system imbalance. The number of quarter-hours with positive and quarter-hours with negative system imbalances was quasi the same within a year in 2018-2022 (48-52 %).. In 2021 the share of quarter-hours with negative system imbalances, however, rose to 57%.

152. The size of the imbalances in 2021 also shifted. On average in the period 2016-2020 during 72% of the quarter-hours per year, the system imbalance was between – 150 MW and + 150 MW (the range in which the alpha component in the imbalance price remains 0 €/MWh, according to the methodology implemented since 2020). In 2021 this share decrease to 67%. The darker areas in Figure 7-2 show the range for each year for the 15th and 85th percentile (i.e., the middle 70% of the observations): for 2021, the darkest area shifts left up to a system imbalance of -192MW.

153. During nearly all quarter-hours the system imbalance remains below 500 MW (in positive or negative direction). System imbalances above 1000 MW occur rarely (see Table 7-6). Such large imbalances did occur more in 2019, with extremes of +1342 MW and -1602 MW. In 2021 there was also a relatively high occurrence of large system imbalance with 11 quarter-hours showing a negative system imbalance of more than 1000MW.

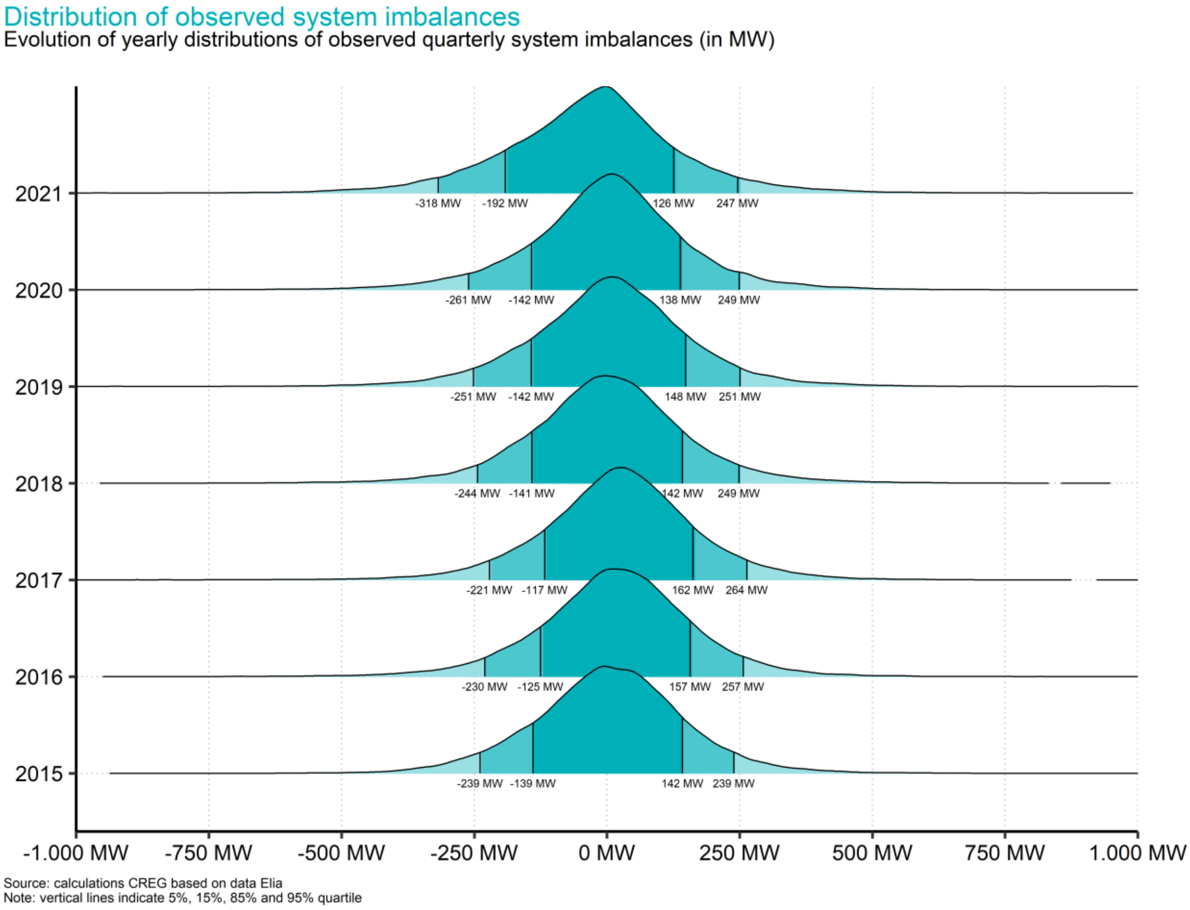


Figure 7-2 Distribution of observed system imbalances

Number of quarter-hours	OFF-CHART OBSERVATIONS										
	[-1.700 - -1.600]	[-1.600 - -1.500]	[-1.500 - -1.400]	[-1.400 - -1.300]	[-1.300 - -1.200]	[-1.200 - -1.100]	[-1.100 - -1.000]	[1.000 - 1.100]	[1.100 - 1.200]	[1.200 - 1.300]	[1.300 - 1.400]
2015	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	1	0	0	0	0
2017	1	0	0	0	2	0	3	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0
2019	1	0	1	1	1	2	2	1	4	1	1
2020	0	0	0	0	0	0	1	1	0	0	0
2021	0	0	1	0	0	5	5	2	0	0	0

Table 7-6 Distribution of observed system imbalances: outliers

154. In 4% of the time (about 1400 quarter-hours, slightly increasing to 1600 quarter-hours in 2021), the system imbalance changes direction towards an (absolute) value of more than 150 MW from one quarter-hour to the next. This number does not fluctuate much from one year to another.

155. Each year, more than 75% of the occurrences of system imbalance of more than 150 MW (in positive or negative direction) lasted one or two quarter-hours.

156. In 2021, on 121 occasions a large system imbalance of 150 MW (in positive or negative direction) lasted more than 2 hours, of which 8 times longer than 5 hours. The longest period in 2021 lasted 28 consecutive quarter-hours: an negative system imbalance ranging between - 232MW and -540 MW occurred on January 31st from 00:00 until 07:00.

7.3.2. Imbalance prices

157. After a decreasing trend between 2018-2020, the imbalance price in 2021 rose strongly to an average of 100€/MWh. The increase is especially visible for quarter-hours with negative imbalance in which the imbalance price is set by the "MIP" (i.e., the marginal incremental price or the highest price for activated upward aFRR energy or imbalance netting or activated upward mFRR energy) showing an average of 172€/MWh. This observation is in line with observations on system imbalances and offered balancing energy prices. In comparison to previous years, offered balancing energy prices are higher for the same volumes activated. In addition, more and particularly larger system imbalances push the marginal price for incremental activations up as energy further up the merit order of positive balancing energy is being activated.

158. For quarter-hours for which the imbalance price is based on the "MDP" (i.e., the marginal decremental price or the lowest price for activated downward aFRR energy or imbalance netting or activated downward mFRR energy), the average value in 2021 was around 6€/MWh. Although on average this value is positive, during more than 3700 quarter-hours (more than 10% of the time) of positive system imbalance the imbalance price was negative, especially in the period February to August.

(€/ MWh)	Average imbalance price		
	Overall	**If based on MIP**	**If based on MDP**
2015	43,6	78,1	11,3
2016	35,0	62,8	10,6
2017	42,3	82,0	9,4
2018	53,8	98,5	12,1
2019	39,6	76,6	5,3
2020	33,8	70,3	-0,9
2021	100,3	171,7	5,7

Source: calculations CREG based on data Elia

Table 7-7 Yearly average imbalance prices

159. The imbalance price is reaching more extreme values in the last years. Since 2019, the imbalance price if based on the MIP has reached values of more than 2.000 €/MWh. The maximum in 2021 is even 3.200 €/MWh.

160. The imbalance price if based on the MDP has reached values lower than - 320 €/MWh in 2019 and 2020 and even -565 €/MWh in 2021.

(€/MWh)	Maximum imbalance price	
	If based on MIP	If based on MDP
2015	822,9	-314,0
2016	1.510,3	-303,8
2017	652,8	-232,3
2018	901,5	-203,5
2019	2.163,5	-323,9
2020	2.297,4	-378,5
2021	3.199,9	-565,0

Source: calculations CREG based on data Elia

Table 7-8 Yearly maximum imbalance prices

161. The impact of the new determination of the alpha component starting from January 2020 is visible. The average alpha value is well above 1 €/MWh and the maximum alpha value of 200 €/MWh has been reached in both 2020 and 2021, both in case of positive and negative imbalances.

162. In 2021, the average alpha value in case the imbalance price is based on the MDP, was 4,6 €/MWh (even 16,1 €/MWh when only taking into account the quarter-hours during which the alpha is larger than zero).

(€/MWh)	Alpha component if imbalance price is based on MDP		
	Average	Average (Alpha =/= 0) (i)	Maximum
2015	0,7	2,4	39,7
2016	0,9	2,7	35,4
2017	0,9	2,5	20,7
2018	0,8	2,7	28,5
2019	0,8	2,7	71,7
2020	3,4	12,9	199,8
2021	4,6	16,1	200,0

(i) This column shows the average value for the quarter-hours during which the alpha component is not 0 € / MWh

Source: calculations CREG based on data Elia

Table 7-9 Alpha component if imbalance price is based on MDP

163. In 2021, the average alpha value in case the imbalance price is based on the MIP, was 6,7 €/MWh (even 18,4 €/MWh when only taking into account the quarter-hours during which the alpha is larger than zero).

(€/MWh)	Alpha component if imbalance price is based on MIP		
	Average	Average (Alpha =/= 0) (i)	Maximum
2015	0,7	2,2	24,1
2016	0,7	2,7	30,1
2017	0,8	3,0	86,7
2018	0,8	2,7	27,9
2019	0,9	2,8	70,5
2020	4,4	15,3	199,9
2021	6,7	18,4	200,0

(i) This column shows the average value for the quarter-hours during which the alpha component is not 0 € / MWh

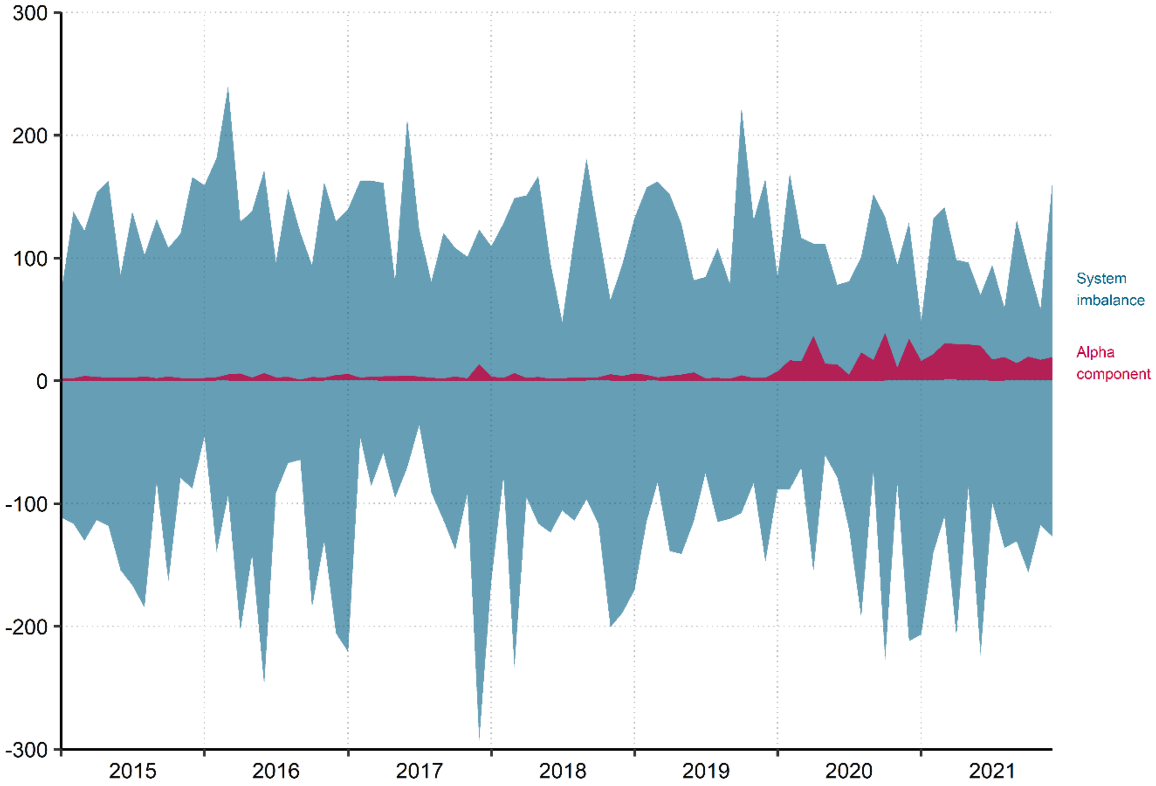
Source: calculations CREG based on data Elia

Table 7-10 Alpha component if imbalance price is based on MIP

164. Figure 7-3depicts the evolution of the system imbalance and the alpha component per quarter-hour from 2015 to 2021. The impact of the new design of the alpha component as of the 1st of January 2020 is clearly visible. However, the new alpha design did not help to decrease the system imbalance compared to levels in the previous years. Consequently the CREG is analysing whether the alpha can still be considered as an efficient price signal.

System imbalances and alpha components

Evolution of maximum and minimum values per month for daily average system imbalance (in MW) and alpha component (in €/MWh)



Source: calculations CREG based on data Elia

Figure 7-3 System imbalance and alpha components

8. NON-BALANCING ANCILLARY SERVICES

165. The security of the system also relies on the non-balancing ancillary services for voltage services (via the change in reactive power production or absorption) and for restoration in case of a blackout (black-start ancillary services).

166. The ancillary services for reactive power management went through a substantial product change between 2015 and 2016. Since then, reservation costs for contracting the ancillary service are no longer foreseen except in exceptional cases (for instance investments or tariffs costs). The reservation cost for voltage services in 2021 were nonetheless substantially higher than in the previous years, at a level of 2,3 M€: this was for a large part due to the reimbursement of the *"tariff for the power put at disposal"* (in case the delivery of voltage services caused the provider to be confronted with this tariff).

167. Providers of voltage services are mainly remunerated for the activation of reactive power, meaning a change towards more reactive power production (or less absorption) in case of low voltage levels and a change towards more reactive power absorption (or less production) in case of high voltage levels. The activation costs have decreased since the introduction of the new design in 2016 reaching their lowest point so far in 2018. In 2021 the activation costs have increased with 7% compared to 2020 to a total of 14M€.

(k€)	2015	2016	2017	2018	2019	2020	2021
Contracting	7.046	635	501	233	477	241	2.268
Activation	0	17.414	12.281	10.985	13.834	13.084	13.940
TOTAL	7.046	18.049	12.781	11.218	14.311	13.325	16.208

Source: calculations CREG based on data Elia

Table 8-1 Reactive power costs

168. Providers of black-start restoration services receive a remuneration for the daily availability of each black-start unit. The reservation of black-start ancillary services further decreased slightly to 6.9 M€, its lowest level in the last six years.

(k€)	2015	2016	2017	2018	2019	2020	2021
TOTAL	6.262	7.192	7.274	7.279	7.323	7.041	6.854

Source: calculations CREG based on data Elia

Table 8-2 Black start costs

169. The (reservation) cost for the black start service (as for balancing capacity) is supported equally by a withdrawal and an injection charge, subject to a cap on the injection charge. This cap is determined according to an EU benchmark on injection charges. The activation and reservation costs for contracting reactive power reserve are fully covered by consumers.

9. CONCLUSIE

In this study, the CREG analyzed the state and the functioning of the Belgian wholesale electricity markets. Historical evolutions are presented as a background to the recent trends, with a focus on 2021.

The CREG presented the evolution of the Belgian total load and electricity consumption in chapter 1. Chapter 2 focused on the installed capacity, generated energy, availability and carbon intensity of the production units. In chapter 3, the physical import and export of electricity from and to neighboring countries was presented.

In the subsequent chapters, linking to previous chapters, the sequence of electricity markets were presented, starting with the long-term timeframe (chapter 4) over the day-ahead (chapter 5) and intraday markets (chapter 6) to the balancing timeframe (chapter 7). Finally, an overview of some non-balancing ancillary services were presented in chapter 8

The Board of Directors of the CREG approved this study at its meeting of 12 May 2022.

For the Commission of Electricity and Gas Regulation:

Andreas TIREZ
Director

Koen LOCQUET
Acting President of the Board of Directors

LIST OF FIGURES

LIST OF TABLES

REFERENCES

Works referred to in this study include:

- Study (F) 2229v on the functioning and the price evolution of the Belgian wholesale electricity market – Monitoring Report 2020
- Study (F) 2289 on the increase in electricity and gas prices in Belgium
- Study (F) 2183 on the compliance of ELIA TRANSMISSION BELGIUM SA with the requirements related to the transmission capacity made available for cross-zonal trade in 2020
- Study (F) 2350 on the compliance of ELIA TRANSMISSION BELGIUM with the requirements related to the transmission capacity made available for cross-zonal trade in 2021

Figures in this study were designed with ggplot2, an open source data visualization package for the R programming language:

- Wickham H. (2016). Ggplot2: Elegant Graphics for Data Analysis. Springer-Verlag New York. ISBN 978-3-319-24277-4, https://ggplot2.tidyverse.org

Other R packages used for this study include:

- *"tidyverse"*: Wickham et al., (2019). Welcome to the tidyverse. Journal of Open Source Software, 4(43), 1686, https://doi.org/10.21105/joss.01686
- *"ggridges"*: https://cran.r-project.org/web/packages/ggridges/index.html
- *"treemapify"*: https://cran.r-project.org/web/packages/treemapify/index.html
- *"patchwork"*: https://cran.r-project.org/web/packages/patchwork/index.html