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 2020

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

The focus of this study is the evolution of the Belgian electricity markets in 2019 and 2020, yet observations are presented in light of historical and more recent evolutions. Where available, historic data dating back to 2010 are presented and where relevant, more recent observations (in 2021) are included in order to present the most complete overview possible.

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 market;
- the sixth chapter covers the intraday markets;
- the seventh chapter deals with the balancing timeframe; and
- the eighth 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 a glossary, a list of abbreviations, a list of tables and a list of figures used throughout the study.

The Board of Directors of the CREG approved this study at its meeting held on 21 October 2021.

EXECUTIVE SUMMARY

In 2020, the total **load of the Belgian electricity network** reached 81,2 TWh. This represents a significant 4,5% decrease compared to the preceding year and can – for a large part – be attributed to the decrease in electricity consumption in light of measures against the COVID-19 pandemic. Nevertheless, the decreasing trend in the load of the Belgian electricity network has, as in other countries, been witnessed since a number of years, therefore suggesting a more structural decrease: the total load in Belgium has decreased by 10,2% since 2010 (90,4 TWh) and by 6,9% since 2015 (87,2 TWh).

The evolution of the peak load reflects this downward trend: the highest observed load of the network per year reached only 13.117 MW in 2020, only 7 MW higher than the lowest peak load (13.110 MW in 2014) in the observed 10-year period and significantly below the values seen in previous years. The baseload of the Belgian network (i.e. the lowest observed hourly load) remained relatively stable at 6.287 MW.

Seasonal and meteorological conditions strongly affect these load values: also for 2019 and 2020 the load of the network tends to increase in case of lower daily temperatures, in line with observations based on historical data.

Similarly to the decrease of the total load, consumption from the distribution network has shown a steady decrease in the last three years, reaching an all-time low total of 48,7 TWh in 2020. The decrease since 2019 is most pronounced in the Brussels region, nevertheless also Flanders and Wallonia experienced strong reductions of the electricity consumption.

At the same time, the combined capacity of all **electricity generation** units has expanded greatly in the previous years, resulting in a net increase of 4,6 GW between 2014 and 2020. This increase can be attributed mainly to the steady deployment of additional wind (+ 2.835 MW) and solar generation units (+1.069 MW). At the same time, nuclear and hydroelectric capacity remained at stable levels, while capacity based on fossil fuels slightly increased (+701 MW).

The increase in generation capacity does not translate into an increase in the generated electricity. While total generation varies strongly from one year to another (with the highest output since 2011 even in 2019 at a value of 78,8 TWh), we observe a general trend towards lower levels of electricity generation in Belgium,.

Focusing on the electricity generated per fuel type, we witness a strong decrease between 2010 and 2020 of electricity produced from nuclear and gas-fired generation units, while production from wind turbines and solar panels mark strong increases. In relative and absolute terms, however, the production levels from nuclear and gas-fired units remain very high; these make up respectively 44,3% and 28,6% of the total electricity generated in Belgium in 2020.

The difference between the electricity generated and the installed capacity can be explained mainly by two reasons. Firstly generation units are not always available due to planned and unplanned outages. Secondly, generation depends on electricity demand, which is decreasing : not all generation capacity is necessary at all times and depending on the relative position of each unit in the merit order, different generation units (or different technologies or fuel types) have a lower or higher utilization rate or capacity factor .

The composition of the yearly total output of the Belgian production park determines the carbon intensity of the electricity mix ; its evolution can be analysed in light of the climate ambitions of Belgium and its neighbouring countries. In 1990, the carbon intensity of Belgium's electricity generation was at 358 grammes of CO2;eq per kWh. A steady decrease over the years led to 174 gCO2;eq/kWh in 2019

(-48,6%). The carbon intensity was nonetheless higher during specific years (in 2015 and 2018) when more electricity from fossil fuel sources had to compensate the reductions in nuclear generation due to a lower availability of these latter units.

Through its interconnections with the Netherlands, France, Luxembourg, Germany and the United Kingdom, Belgium can export its surplus of electricity (when generation exceeds demand) and import (when demand exceeds generation). Since 2015, Belgium has been structurally importing electricity most of the time (with some short, temporary exceptions). From 2019 onwards however, as a result of lower demand and higher self-generation of electricity, Belgium has become a net exporter.

This observation is linked to the entry into operation of the Nemo Link connector in the beginning of 2019, consisting of a 1.000 MW cable to (most often) export electricity to the higher-priced Great-Britain. At the same time, electricity load has decreased and the generation in the Belgian zone has increased in 2019 (and to a lesser extend 2020) compared to 2015.

The evolution towards higher values for the import and export of electricity has been made possible by the increased efficiency of the allocation of transmission capacity (in the different timeframes) and the investments in the transmission network (most notably through the Nemo Link and ALEGrO interconnectors). Belgium has 13,5 GW of installed capacity on the borders with the aforementioned countries.

Prices for electricity observed on the **futures markets for yearly, quarterly and monthly products** tend to follow similar general patterns as the day-ahead price. The extremely low day-ahead prices in the first months of 2020 following the lockdown measures during the COVID-19 pandemic have, nevertheless, only been reflected to a certain extent in month-ahead and quarter-ahead prices, yet not in the year-ahead prices. In general, prices for long-term products were higher in 2019 and 2020 than their day-ahead reference, indicating anticipated price increases.

When analysing the contracts by looking at their delivery period, it is clear that for the years 2019 and 2020, purchasing electricity on the spot markets was cheaper than doing so through yearly, quarterly and monthly contracts. Contrarily, selling electricity through the available futures contracts was more interesting than on the spot markets.

From 2021 onwards, the increases observed in the spot prices for electricity and its underlying commodities have been reflected – yet with some delay and to varying extents – in the prices for futures contracts. Notably for delivery in 2022, buyers of electricity have to pay historically high prices, exceeding 120 € / MWh through one year-ahead contracts.

Elia sells, in the yearly and monthly timeframes, its interconnection capacity to serve as a hedging instrument against price differentials between bidding zones for market participants. Historically, relatively stable volumes have been allocated on the Dutch and French border, and recently on the border with Great-Britain as well. This does not imply stable prices for this capacity: the price for a MWh/h of interconnection capacity not only depends on the available and requested volume, or the concentration of demand for it, but also crucially on the value as a hedging instrument – reflected in the anticipation of the price differential between two bidding zones by a market participant. In general, these markets are relatively competitive and little demand-side concentration is observed. Nevertheless, it is clear that the desire for market participants to obtain interconnection capacity in the long-term timeframe clearly exceeds, by a factor 10 to 15 depending on the observed border and direction, the capacity that is actually sold by Elia.

The aforementioned observations related to the physical net position of Belgium in real time are mainly driven by the evolutions of Belgium's net position in the day-ahead timeframe as a result of the Single Day-Ahead Coupling processes. Since 2015, Belgium's day-ahead net position has shifted from a structural net importing to a net exporting position in 2019, 2020 and in the first half of 2021.

The observed **day-ahead prices**, resulting from the market coupling processes between Belgium and its neighbouring countries, have shown remarkable movements in the last years. Prices dropped in 2019 from their – at the context of the time – high levels at the end of 2018 and reached, in light of the COVID-19 pandemic, all-time low values in the second quarter of 2020. Since then, day-ahead prices have shown a steady increase in Belgium and its neighbouring countries, reaching the average historic levels towards the end of 2020 and rising further in the first half of 2021. Since August and September 2021, the observed prices reached all-time high values, averaging well above 100 €/MWh on a monthly basis. Compared to the period between 2015 and 2018, the market coupling resulted more often in negative prices in 2019, 2020 and 2021 in Belgium and most of the observed countries – indicating an increased variability of the price signal.

At the same time, despite the pronounced movements – in both directions – of these prices, **price convergence** has strongly improved since 2015 and the start of the CWE flow-based market coupling. Several factors have, in CREG's assessment, led to the remarkable increase in price convergence, among which the introduction of the 20% minRAM patch, the split of the German/Luxembourgish and Austrian bidding zone and the entry into force of the 70% requirement from the Clean Energy Package. In general, it seems that the continued efforts of the CWE NRAs and TSOs to improve the functioning of the CWE FBMC have resulted in these improvements of the market coupling results.

The introduction of the 70% requirement in the Clean Energy Package, obliging Elia (as well as other European TSOs) to increase the minimum levels of cross-zonal capacity to be made available to cross-zonal exchange, has been monitored duly by the CREG. In 2020, Elia complied with these legal provisions during 81,3% of all hours and on 99,2% of all observed network elements.

These elements have not only impacted the occurrence of price convergence, but also the levels of **interconnection capacity** available to the day-ahead cross-zonal markets. Market participants have been able to access historically high levels of cross-zonal capacity, both in the import and export direction as well as in absolute and average terms. Towards the end of 2020, some hours recorded maximum import and export opportunities reaching not less than 7.500 MW.

Loop flows through the Belgian network have historically had a significant impact on the ability of Elia to provide cross-zonal capacity for importing (and to a lesser extent, exporting) electricity to Belgium. In recent years, the impact of these loop flows has decreased. The average trend as well as the distribution of the loop flows changed, not drastically but at the same time unmistakably. Still, they tend to follow the same structural north-to-south direction: electricity flows coming in on the Dutch border and going out on the French border.

In the **intraday timeframe**, Belgium is coupled to other European countries through XBID under the Single Intraday Coupling project. The liquidity of this market has improved strongly, reaching growth levels between 10 and 15% of the number of matched trades on a quarter-to-quarter basis since the go-live of the XBID solution in June 2018.

While no single intraday price exists under a continuous trading mechanism such as XBID, (volume-weighted) reference prices can be calculated. These reference prices show, on average, a remarkably close alignment to the day-ahead price. Nevertheless, high price differentials can be observed during some hours, even though the mean and median values of these differentials are very close to zero.

In terms of available capacity, CWE TSOs initially provide the left-over capacity from the day-ahead timeframe. Elia, as well as their CWE colleagues, may then propose to increase or (less often) decrease the capacities for bilateral exchanges on their borders, after which these proposals are accepted or rejected by all CWE TSOs. The analyses show that Elia's increase requests – while issued in nearly 100% of all hours – are only fully accepted by all TSOs in 15,1% of the time. A the same time, Elia rejects capacity increase requests of other TSOs very often (40,8% of the time) but even more often they reject their own request, after having assessed them jointly with other TSOs' requests (45,1% of the time).

In recent years, the designs for **balancing capacity markets** – including FCR, aFRR and mFRR – have been modified to open up these markets to different technologies. Changes in both demand and the design for the supply of balancing capacity have resulted in a rather stable total yearly cost, apart from 2018 (when adequacy risks were identified at the end of the year). The end of 2020 shows the start of an increase of the average costs for FCR and aFRR capacity. Preliminary observations of the 2021 data so far confirm this trend, and will therefore be a point of attention for the CREG.

The cost of mFRR capacity has increased since 2015 and the reason for this is twofold: an increase in the need for mFRR capacity and an increase in the average price per MWh. Early 2021, the amount of mFRR capacity was again lowered by 200 MW. This is due to the change in the dimensioning, as a higher volume of reserve sharing with neighbouring countries is taken into account. The first observations for 2021 show that the average cost for mFRR has also decreased. The CREG will analyse the impact of this change more closely in the next report .

Yearly statistics of the **system imbalances** do not change much from one year to another (with the exception of the higher occurrences of imbalances larger than 1 GW in either direction in 2019). The design of the imbalance price formation serves to incentivise the BRPs to take action to avoid such situations. The occurrences of large (and in some cases, longer-lasting) system imbalances are an attention point for the CREG as the objective should remain a reduction of such events (in frequency and magnitude). Therefore, the question on whether to redesign the imbalance price is on the CREG's agenda in the short term.

The **imbalance price** has, on average, decreased since 2018. In 2020, the average imbalance price is at its lowest point since 2015. However, based on the observations in the first 9 months of 2021 this tendency has strongly reversed. The redesign of the alpha component entered into force as of January 2020 and has materialized in the statistics: the average alpha is 4 times higher in 2020 than in the preceding years. Whether this resulted in the targeted difference of behaviour of the BRP's cannot be concluded, as other influences might be in play.

A more detailed view of the imbalance price shows that extreme values are becoming even more extreme. This is a concern of the CREG, especially as the announced design changes for aFRR and mFRR (in the framework of the European PICASSO and MARI projects) will also affect the imbalance price. As previously mentioned, the design of the imbalance price is of high priority for further investigation.

Finally, the costs for non-balancing ancillary services are presented in the report. Costs for reactive power activation for voltage services have decreased until 2018 following the introduction of a new design in 2016. Nonetheless, these costs increased again to higher levels, reaching 13,1 M€ in 2020. The costs for black-start restoration services have been relatively stable between 2015 and 2020, at around 7M€ on an annual basis.

1. CONSUMPTION

1.1. TOTAL LOAD

1.1.1. At the European level

1. Figure 1 illustrates the evolution of the total electricity load in Belgium and neighbouring countries for the period 2010-2020 . At country level, electricity load fluctuates significantly over the considered period. The Netherlands and Great-Britain are countries with the most year-to-year variations while Belgium's electricity load has been relatively stable between 2010 and 2020.

2. For Germany, France and Belgium, the total load in 2019 was lower than 2010 level while the United Kingdom and the Netherlands are the only countries recording an increase in their total electricity load over that period.[1] In 2020, electricity load dropped significantly for all countries due to the COVID-19 crisis. However, Germany experienced a smaller reduction in its total load than any other selected country (see also Figure 3).

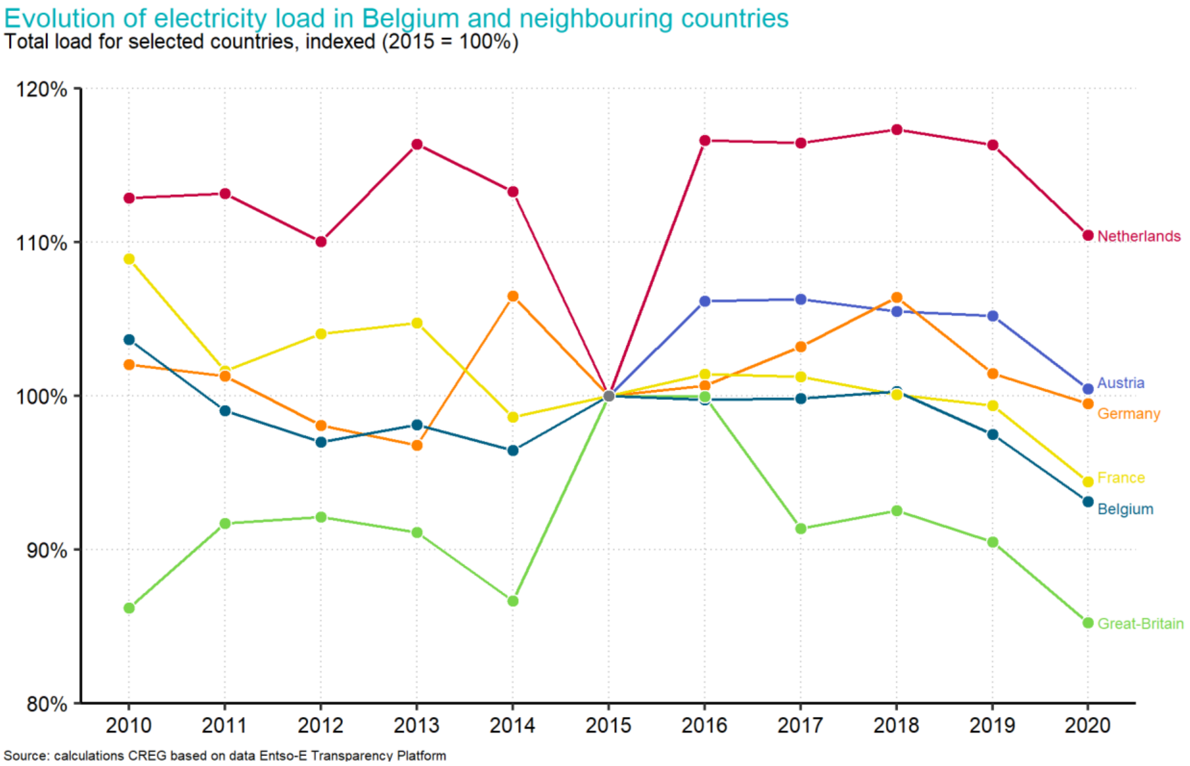


Figure 1 Evolution of electricity load in Belgium and neighbouring countries

3. As illustrated in Figure 2, Belgium's total electricity load in 2020 amounted to 81,2 TWh (-5% vs. 2019). As far as other selected countries are concerned, electricity consumption in 2020 amounted to 476,3 TWh in Germany (-2% vs. 2019), 443,7 TWh in France (-5% vs. 2019), 285,7 TWh in the United Kingdom (-6% vs. 2019), 108,1 TWh in the Netherlands (-5% vs. 2019) and 59,5 TWh in Austria (-4% vs. 2019).

[1] Data for Austria are only available from 2015 onwards.

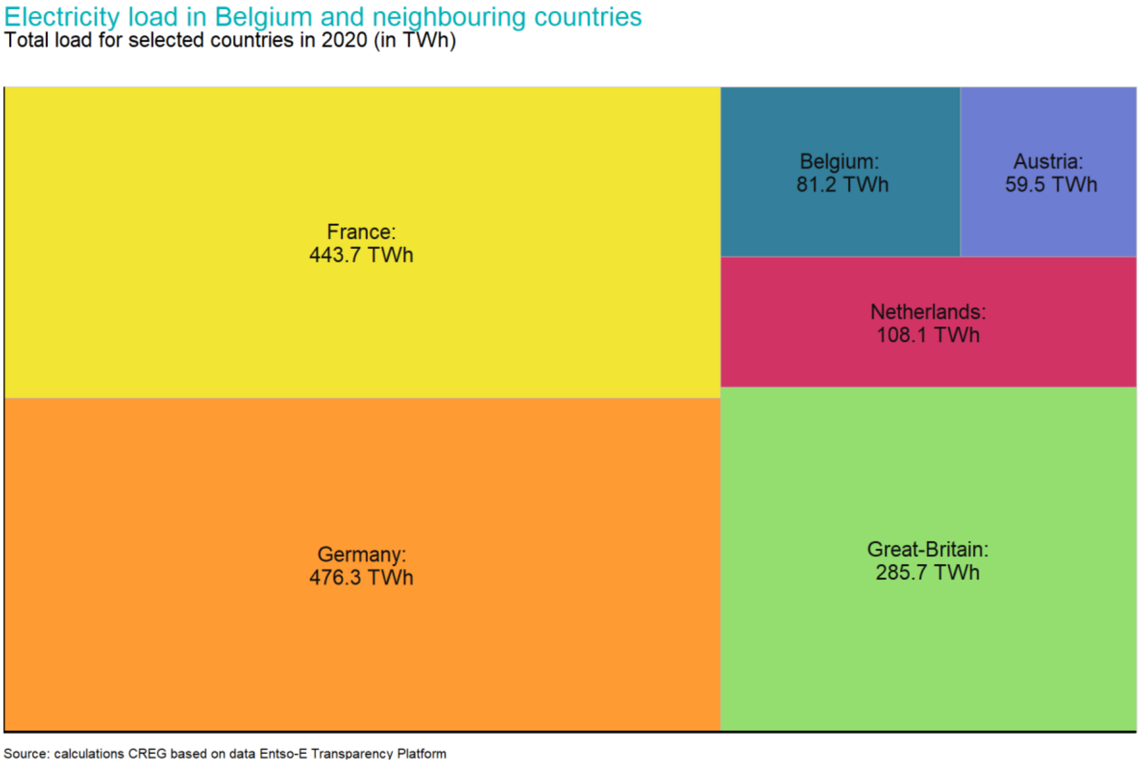


Figure 2 Electricity load in Belgium and neighbouring countries

4. Figure 3 illustrates the impact of the COVID-19 crisis on the total electricity load in the selected countries. Throughout Europe, factories and shops were forced to shut down while many people were working from home because of the confinement measures. As a consequence, the total electricity load dropped significantly in these countries. The impact was more limited in Germany where the total load decreased by only 2% compared to 2019. On the other hand, The United Kingdom was the most impacted country and recorded a reduced electricity consumption of about 6% compared to the previous year. In Belgium, the total load reached 81,2 TWh in 2020, representing a reduction of 5% compared to 2019.

5. Even though 2020 was an exceptional year due to the COVID-19 pandemic and strict confinement measures, the decrease in total electricity load seems to be of a structural nature. Indeed, as illustrated in Figure 1, electricity load in the Netherlands and the United Kingdom fluctuated significantly over the last decade while in Germany, France and Belgium, total electricity load was already lower in 2019 than in 2010.

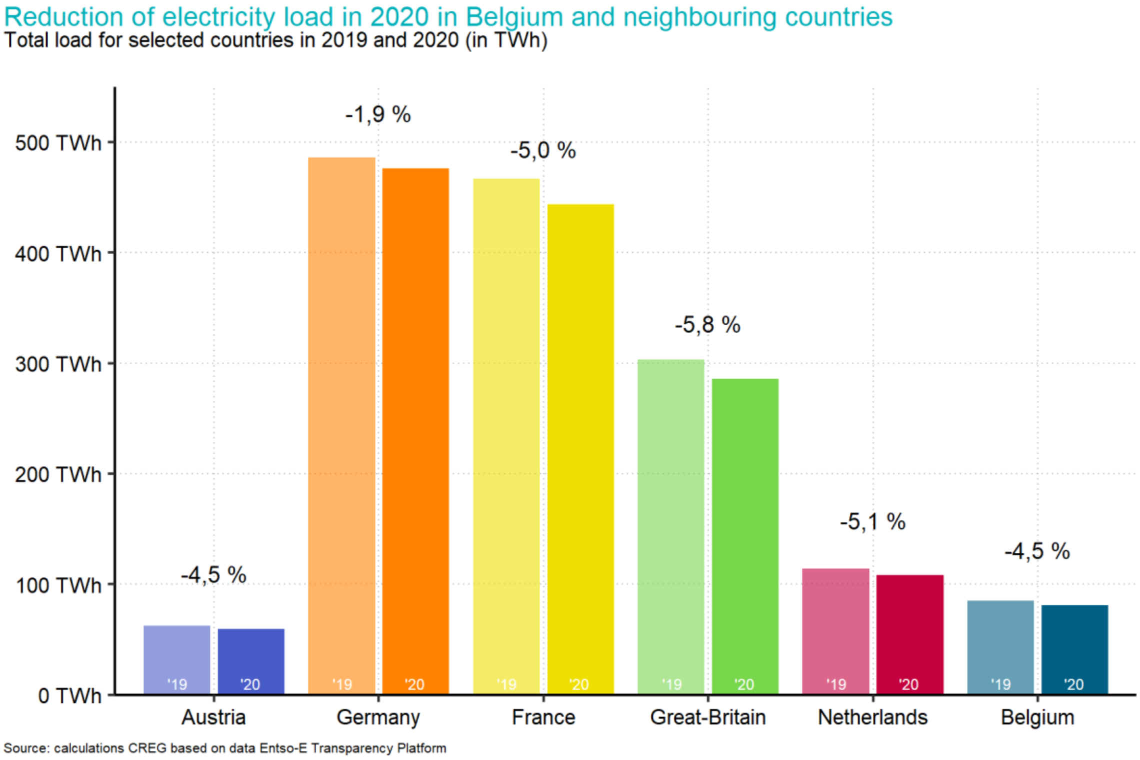


Figure 3 Reduction of electricity load in 2020 in Belgium and neighbouring countries

1.1.2. At the Belgian level

6. Figure 4 shows in detail the evolution of the electricity peak demand in Belgium over the past 10 years. 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 4.

7. The maximum load has been decreasing since 2010 and amounted to 13.117 MW in 2020 (-8% compared to 2010). This negative trend over the period 2010-2020 can also be observed for the load at hours 100, 200 and 400. This tendency has been stabilizing since 2015, with the exception of 2020 (and this might not be due to the COVID-19 crisis since peak load frequently occurs in January and February, meaning before the COVID-19 crisis started). The minimum load remained at the same level between 2010 and 2020 (about 6.300 MW) but it fluctuated considerably between 2013 and 2018 when it reached its maximum level (6.833 MW in 2018).

8. This overall decreasing trend shows that no additional generation capacity is needed in Belgium to accommodate the current load level.

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

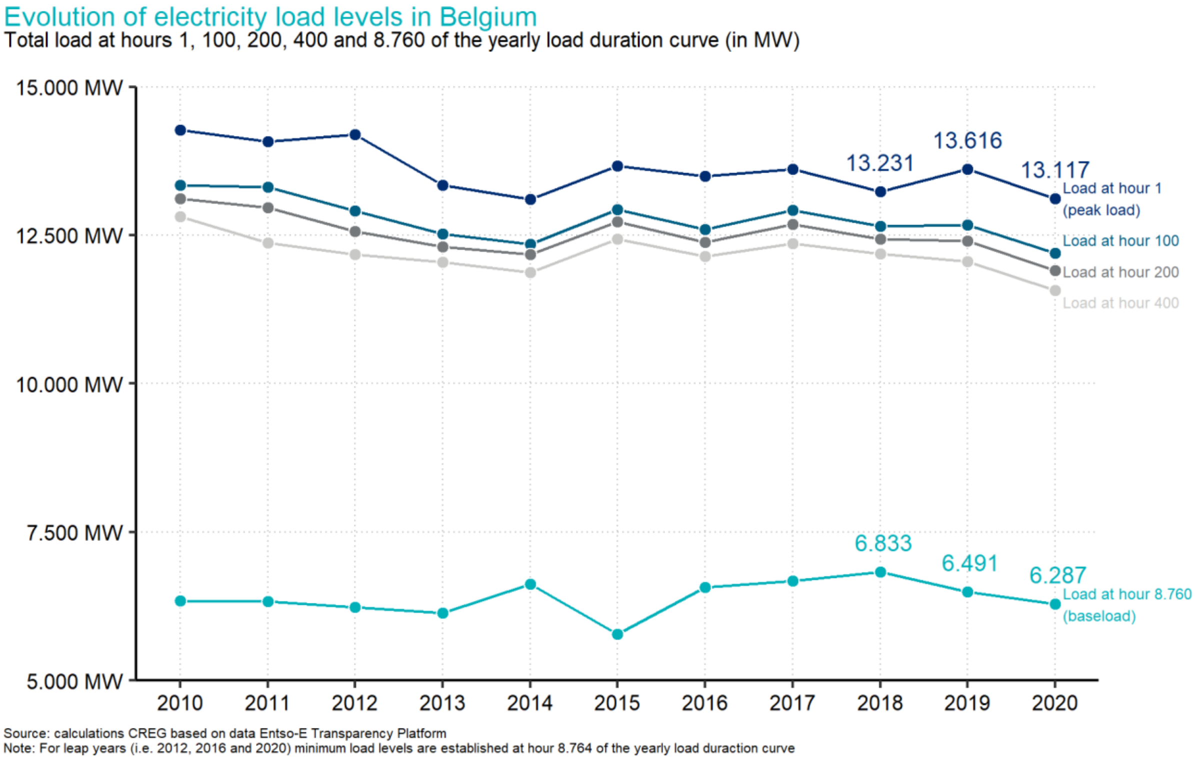


Figure 4 Evolution of electricity load levels in Belgium

1.2. TEMPERATURE SENSITIVITY OF ELECTRICITY CONSUMPTION

9. Figure 5 illustrates the monthly average total Belgian load for the period 2010-2020 (be aware that the Y-axis starts at 8.000 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 2.000 MW).

10. This figure also illustrates the impact of the COVID-19 crisis on Belgium's total electricity load. While the first two months of 2020 were rather warm (thus explaining an already low electricity load compared to previous years), electricity consumption dropped in March when the confinement measures entered into force. In April 2020, the monthly average total load reached its minimum value (8.220 MW) before rising from May as measures were progressively lifted. The only month in 2020 where the total load is situated at approximately the same level as in 2019 (and also significantly above the lowest of the 2010 – 2018 range) is August. In August 2020, a 12-day long heat wave has resulted in a strong surge in the demand for electricity.

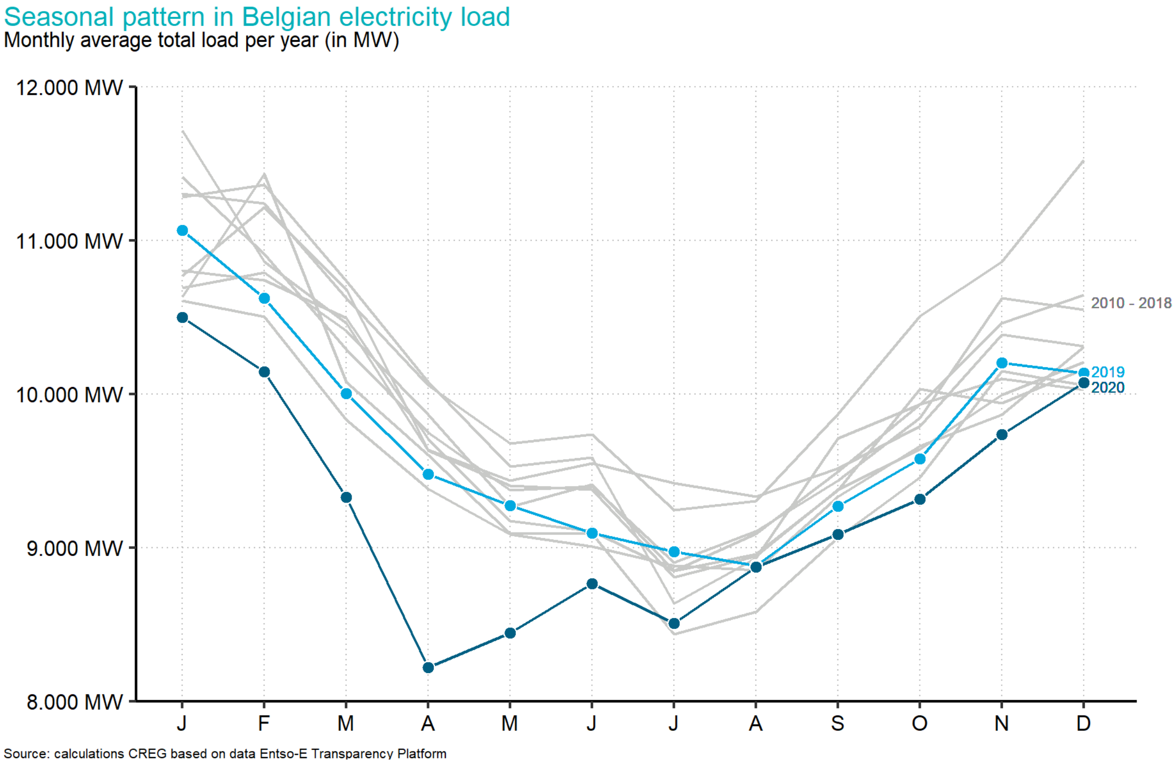


Figure 5 Seasonal pattern in Belgian electricity load

11. Figure 6 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 the summer months. The latter has already been observed clearly in August 2020.

12. The differences in the relationship between 2019 and 2020 can be explained by a rather warm winter in 2020 coupled with a low electricity consumption during the winter months at the end of 2020 as a consequence of the COVID-19 crisis.

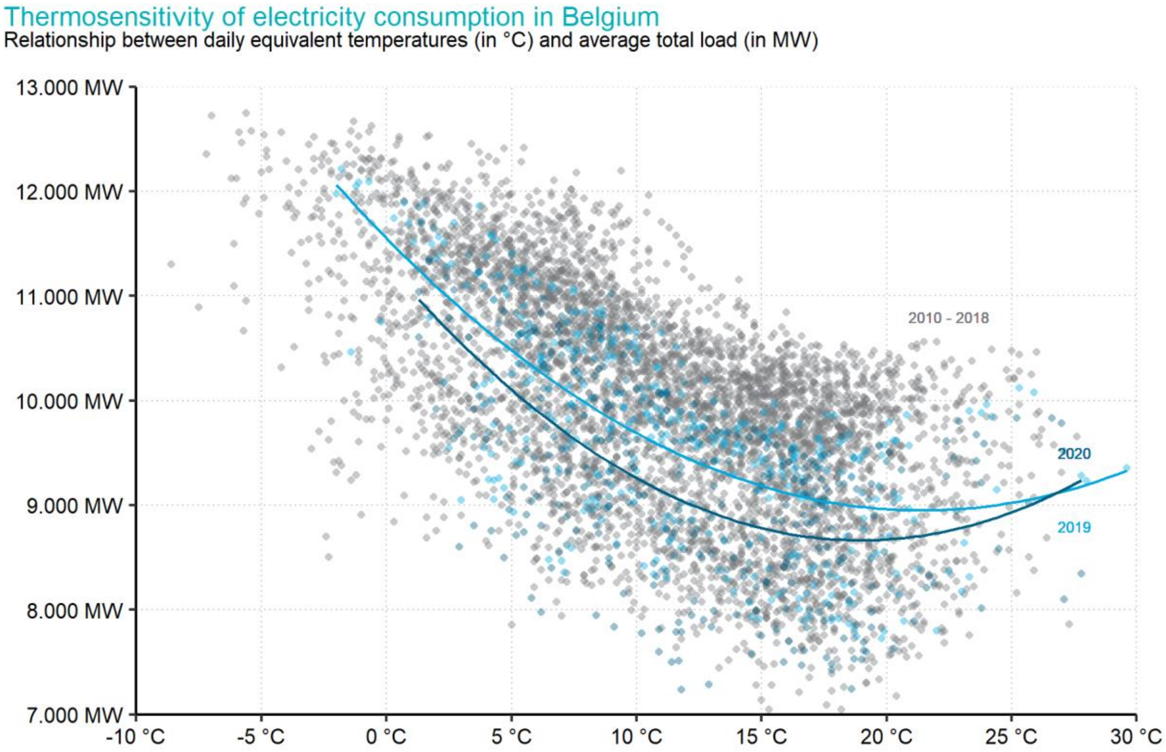


Figure 6 Thermosensitivity of electricity consumption in Belgium

1.3. INDUSTRY AND HOUSEHOLD CONSUMPTION

13. Figure 7 illustrates the evolution of electricity consumption at transmission and distribution levels in Belgium over the period 2010-2020. Households and small industries are connected at the distribution level while most industries in Belgium are connected at the transmission level of the Belgian grid.

14. Over the period 2010-2020, the electricity consumption of end-consumers connected to the transmission and distribution networks of the Belgian grid decreased continuously (from 84,2 TWh in 2010 to 75,1 TWh in 2020). Electricity consumption is twice as high at the distribution level than at the transmission.

15. The figure also shows that electricity consumption at the distribution level is more volatile than at the transmission level. In the past decade, electricity consumption of end-consumers connected to the transmission network stagnated around 27,3 TWh. In 2020, electricity consumption at the transmission level reached 26,4 TWh. On the other hand, electricity consumption at the distribution level decreased between 2010 and 2014 before stabilising around 52,2 TWh. From 2018, it started to decrease again and reached 48,7 TWh in 2020.

16. In 2020, the decrease in electricity consumption was slightly larger at the transmission level (-4,3% vs. 2019) than at the distribution level (-3,8% vs. 2019). This difference could be explained by the lockdown and confinement measures, which forced many factories to shut down or reduce their output.

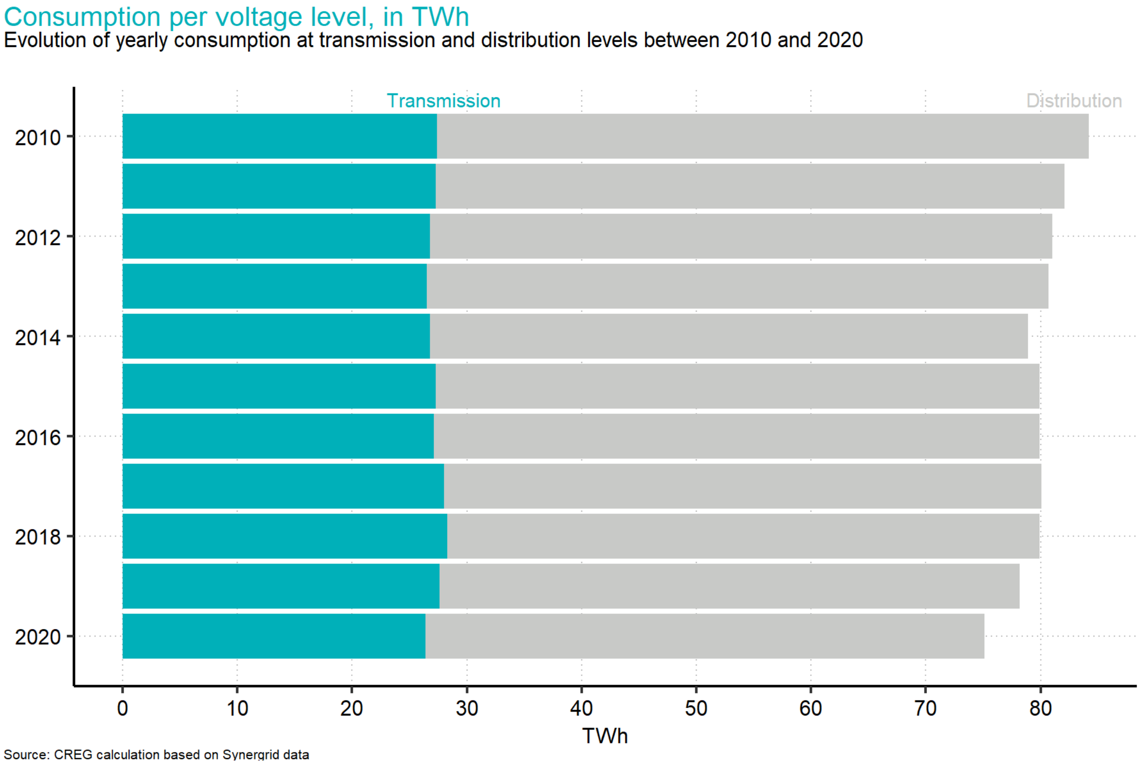


Figure 7 Consumption per voltage level

17. Figure 8 shows the evolution of electricity consumption at distribution level in the three Belgian regions between 2010 and 2020. 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 Brussels, electricity consumption decreased continuously between 2010 (5,2 TWh) and 2020 (3,9 TWh). In Wallonia, electricity consumption remained rather stable between 2010 and 2017 (around 15,4 TWh) before decreasing for three consecutive years. Wallonia's consumption at distribution level then reached 14,1 TWh in 2020. As far as Flanders is concerned, a continuous downward trend can be observed for the period 2010-2020 (35,4 TWh in 2010 vs. 30,7 TWh in 2020).

19. In 2020, Flanders and Wallonia recorded a reduced electricity consumption of respectively 2.2% and 3.8% compared to 2019. On the other hand, the impact of the COVID-19 crisis on electricity consumption was much more significant in the Brussels' area (-14.4% in 2020 compared to 2019). This could be notably explained by the offices being closed and public transports operating at reduced volume.

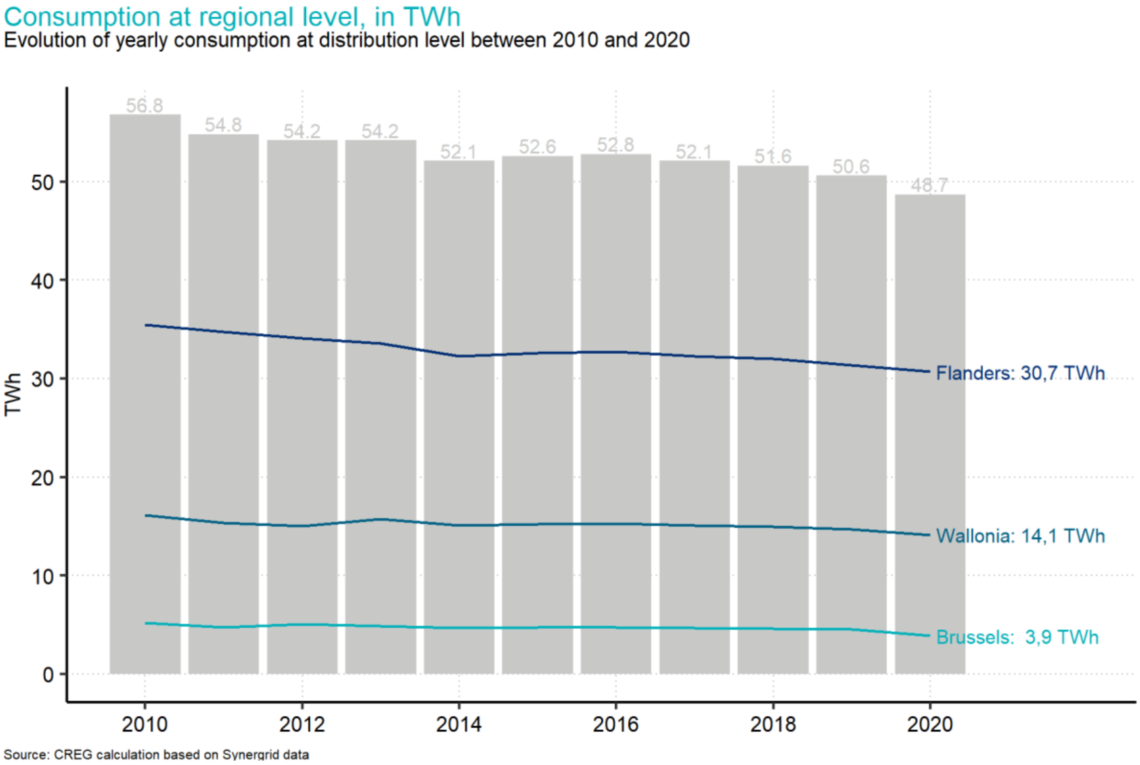


Figure 8 Consumption at regional level

2. GENERATION

2.1. INSTALLED CAPACITY

20. At the end of 2020, the total installed generation capacity[3] in Belgium amounted to 24 GW, compared to 22,5 GW in 2019. The installed generation capacity continuously increased over the 2014-2020 period (+4,6 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 2014 and 2020 while solar installed capacity increased by a factor of 1,4 over the same period. The nuclear and hydropower installed capacities remained stable between 2014 and 2020. On the other hand, installed capacity of fossil plants slightly increased by 700 MW.

21. 2020 was a record year with more than 1,5 GW installed in total: +870 MW in wind installed capacity, +520 MW for solar and +160 MW for fossils [4] (net numbers).

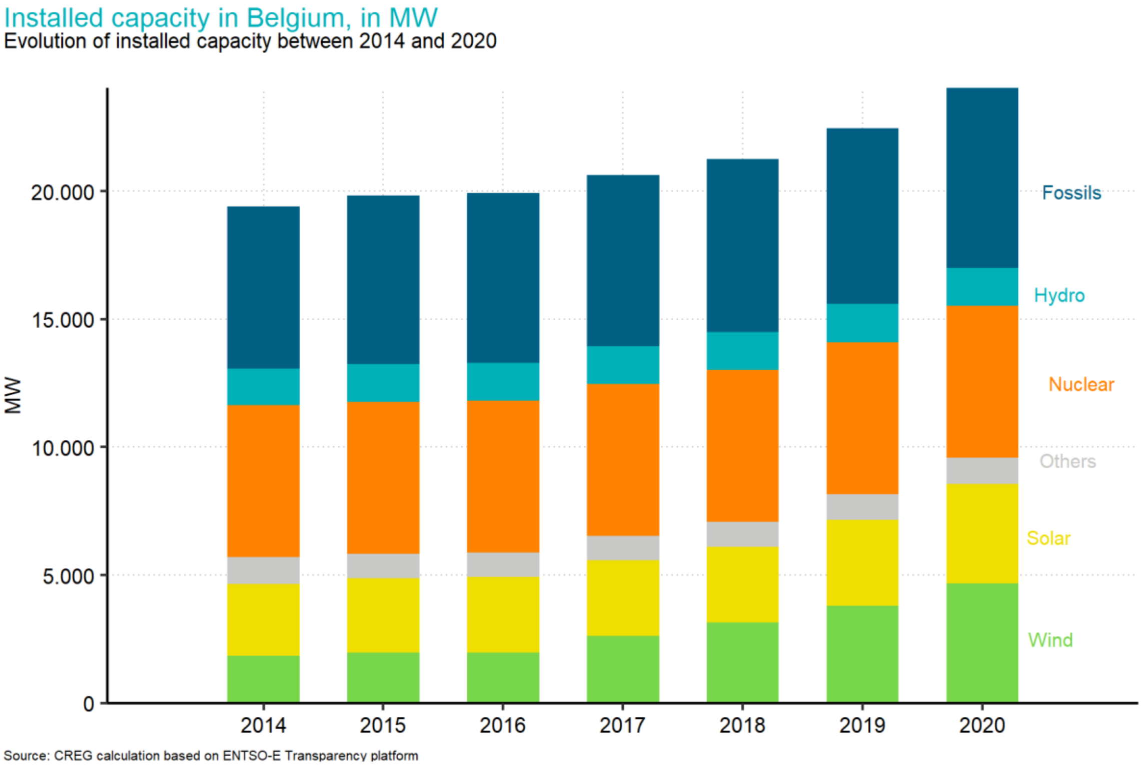


Figure 9 Evolution of installed capacity in Belgium

22. Wind is the technology which experienced the largest increase in installed capacity between 2014 and 2020. More specifically, onshore wind capacity more than doubled in 6 years (1.120 MW in 2014 vs. 2580 MW in 2020) while offshore wind capacity more than tripled over the same period (from 710 MW to 2.250 MW). 2017 was a record year for onshore wind with almost 500 MW installed in that year alone. 700 MW of offshore wind capacity were added in 2020.

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

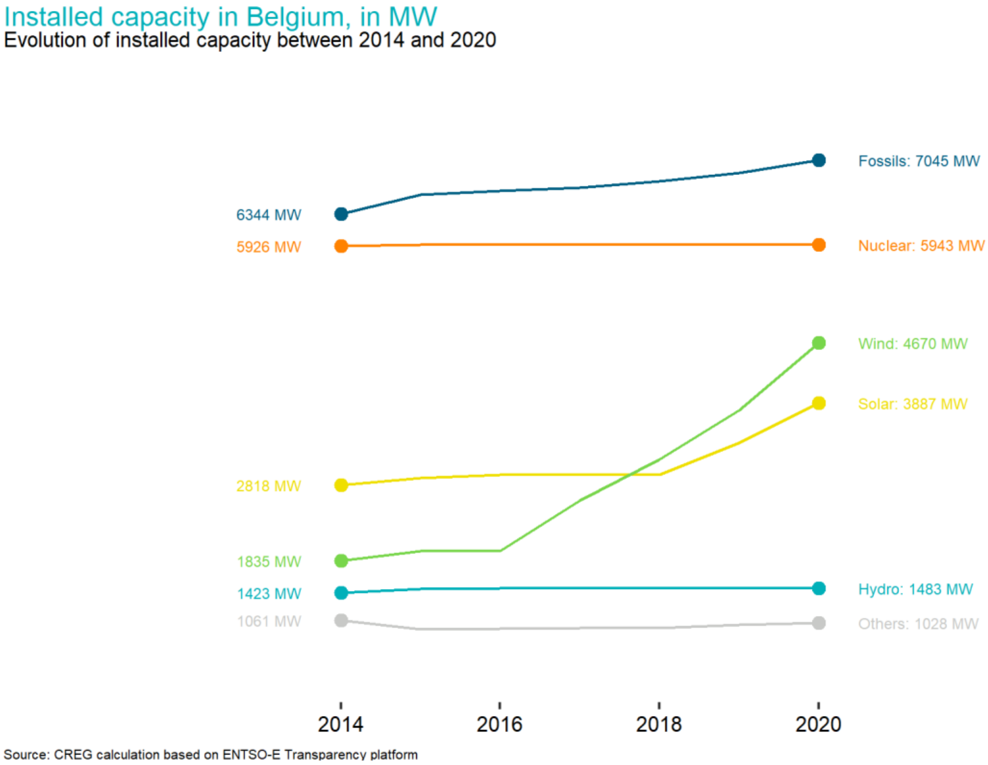


Figure 10 Evolution of installed capacity in Belgium

2.2. AVAILABILITY OF GENERATION ASSETS

23. Figure 11 illustrates the full availability rate of generation units by fuel type in 2020. 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 dot represents a generation unit, while the bigger dots represent the average full availability rate by fuel type.

24. In 2020, seven generation units were fully available for less than 50% of the time. In particular, the Schaerbeek Siomab ST3 unit was unavailable for the entire year because of planned overhaul. The Vilvoorde GT unit (natural gas unit) was fully available for only 18% of the time because of a planned outage from February to September and partial availability limited to some hours of the days for the rest of the year.

25. As far as nuclear units are concerned, the Tihange 1 reactor only produced electricity for a couple of days in 2020 because of a planned maintenance from December 2019 to December 2020. Doel 1 was fully available for only 28% of the time because of a planned maintenance from October 2019 to June 2020. Doel 2 was also under planned maintenance from September 2019 to May 2020, which mainly explains the full availability rate of 32% in 2020. On the other hand, Tihange 2, Doel 3 and Doel 4 were fully available for more than 75% of the time in 2020.

26. The availability rate of individual units or per fuel type do not necessarily reflect the utilization 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).

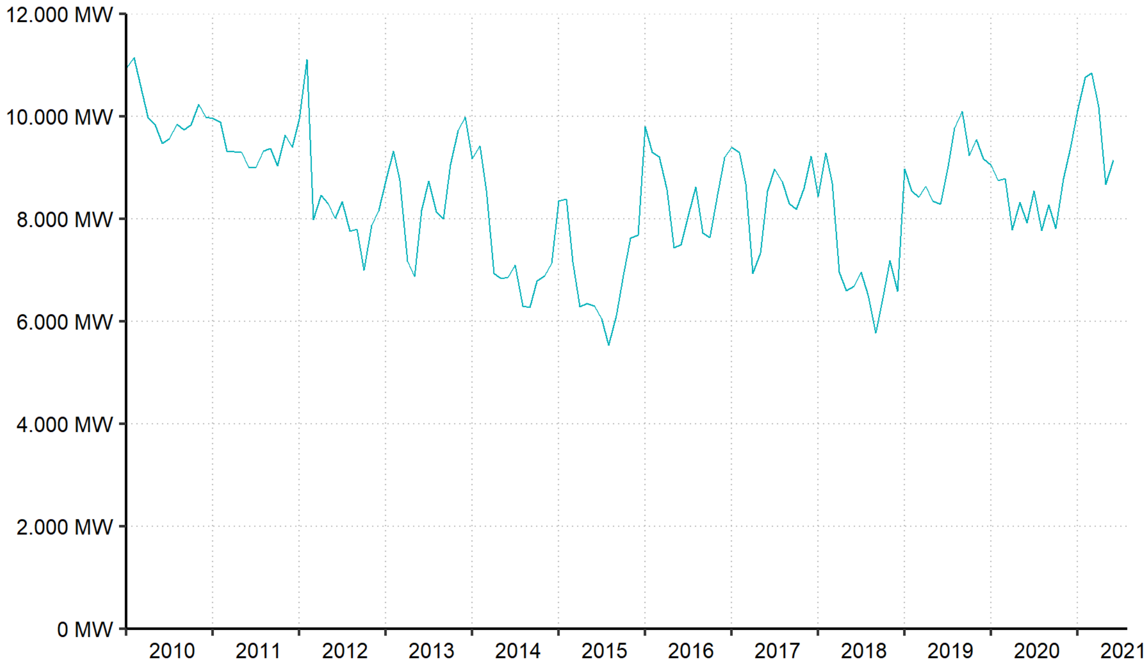
Figure 11 Full availability rate of generation units

2.3. GENERATED ENERGY

27. Figure 12 illustrates the evolution of electricity generation in Belgium between 2010 and the first half of 2021. One can clearly see that electricity generation decreased over the considered period and became much more fluctuating. In 2010 and 2011, the monthly average total generation ranged between 9.000 MW and 11.000 MW. From 2012, largest deltas in monthly average generation can be observed (up to 5.000 MW).

28. It should be noted that the COVID crisis seems to have had no notable impact on electricity generation in Belgium if one compares with the previous years. In the first six months of 2021 (and notably in the winter months), however, electricity generation reached higher levels than the previous years. Average values in January, February and March (respectively 10.111, 10.757 and 10.848 MW) haven't been observed since the winter of 2011-2012.

Evolution of electricity generation in Belgium
Monthly average total electricity generated in Belgium (in MW)

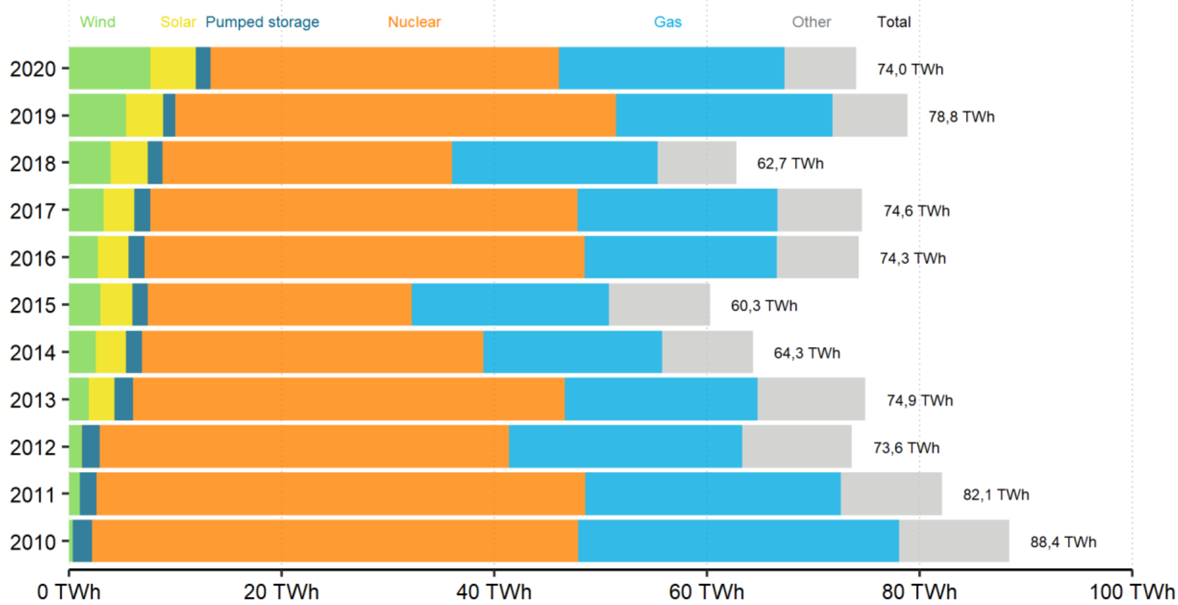


Source: calculations CREG based on data Elia

Figure 12 Evolution of electricity generation in Belgium

29. Between 2010 and 2020, total electricity generation in Belgium decreased by 14,4 TWh, as illustrated on Figure 13. From one year to another, significant changes can be observed between the total electricity generation and the generation mix, reflecting the availability of generation assets but also the increase in installed capacity of renewable energy sources (wind and solar, see also section 2.1 and Figure 10).

Composition of electricity generation in Belgium
Yearly total generation per fuel type (in TWh)



Source: calculations CREG based on data Elia

Figure 13 Composition of electricity generation in Belgium

30. Nuclear generation represents a major share of electricity generation in Belgium. Electricity generation by nuclear plants has shown large year-to-year variations due to planned and unplanned availabilities of several nuclear units. Nuclear generation in 2018 reached its lowest level of annual generation in the past decade (27,3 TWh). In 2020, 32,8 TWh of electricity were produced by nuclear plants, this is a 20% decrease compared to the previous year.

31. Gas fired electricity generation represents 29% of electricity generation in Belgium in 2020, behind nuclear generation. As illustrated in Figure 13 and Figure 14, electricity generated by gas units has been decreasing since 2010 when it represented about 34% of electricity generation in Belgium. In 2020, 21,2 TWh of electricity were produced by gas fired power plants. This is a small increase compared to 2019 (20,3 TWh).

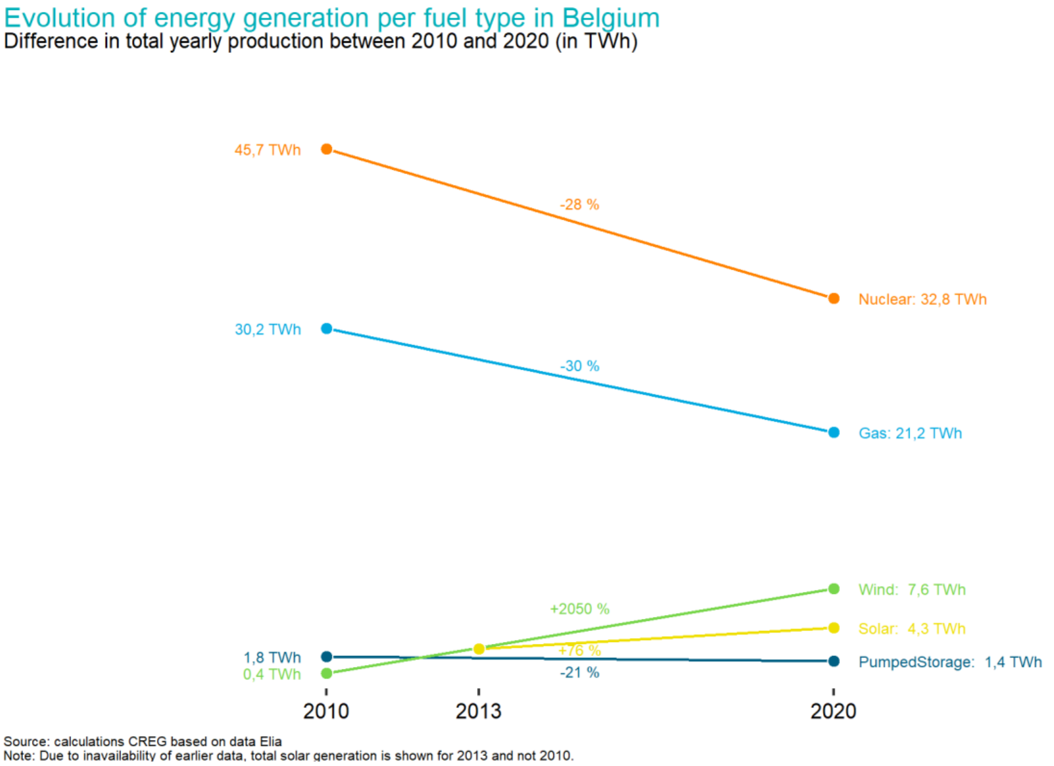


Figure 14 Evolution of electricity generation per fuel type in Belgium

32. On the other hand, the share of renewable energy sources, in particular wind and solar PV, in electricity generation has been continuously increasing since 2010. As illustrated on Figure 13, in 2020, wind and solar PV represented 16% of total electricity generation in Belgium while these sources only represented of 1% of the country total electricity generation in 2010. Wind and solar PV generation amounted respectively to 7,6 TWh and 4,3 TWh in 2020: this is an increase of 2.050% since 2010 (for wind) and 76% since 2013 (for solar).[5]

33. Figure 15 illustrates the monthly total generation per fuel type in Belgium in 2020. The shape of the curve logically follows the curve representing Belgium's average monthly electricity load: in the winter months, generation units must be available in order to meet higher levels of demand for electricity (as shown in Figure 5). The positive difference between electricity load and generation is

[5] Data on the total generated energy from solar PV panels is only available since 2013. This is reflected in Figure 13 and Figure 14.

made up by the net import, discussed in section 3.2 and decentralized production (which is added to the total load discussed in section 1.1).

34. Nuclear generation significantly decreased during the months of June, July and August. Nuclear plants being crucial to maintain generation adequacy, it is typically during the summer months that unavailabilities for maintenance works are planned. During those months, electricity generation from gas fired power plants increased, firstly, to compensate the planned unavailability of nuclear power plants, and, secondly, also because gas prices during the summer of 2020 were extremely low due to an abundance of gas as a result of the COVID-19 crisis.

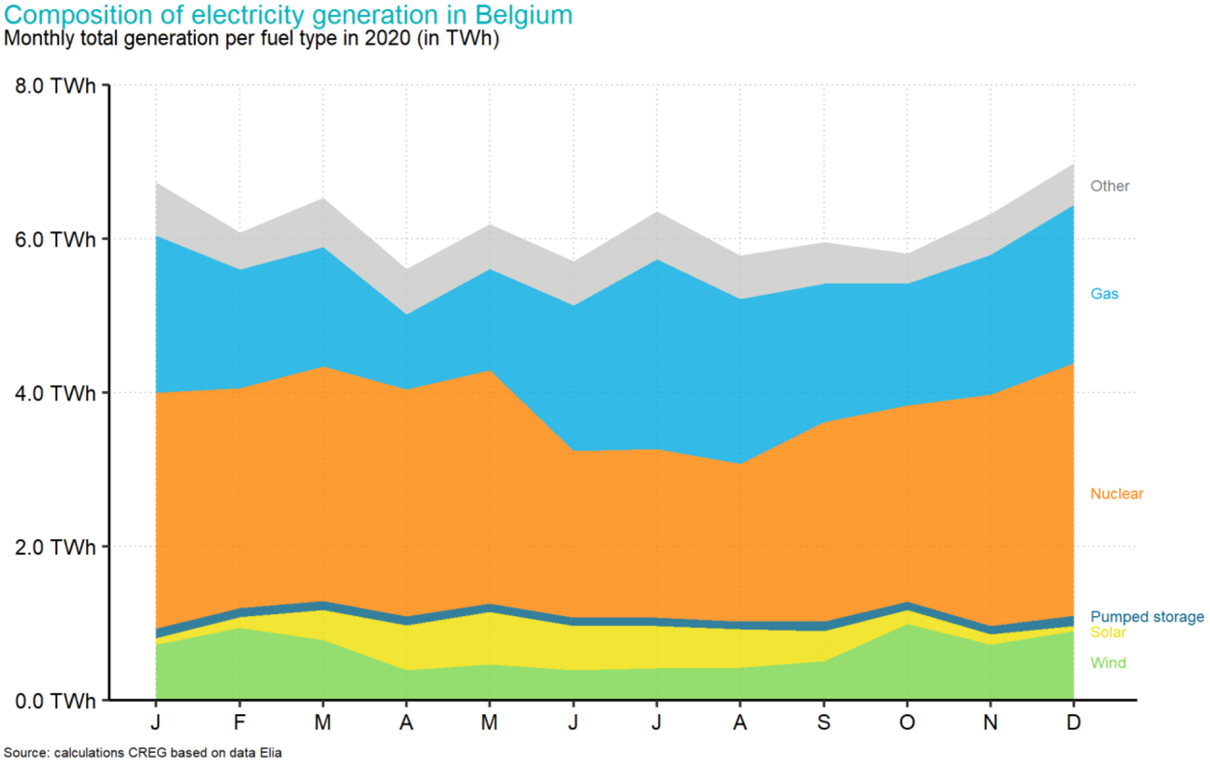


Figure 15 Composition of electricity generation in Belgium

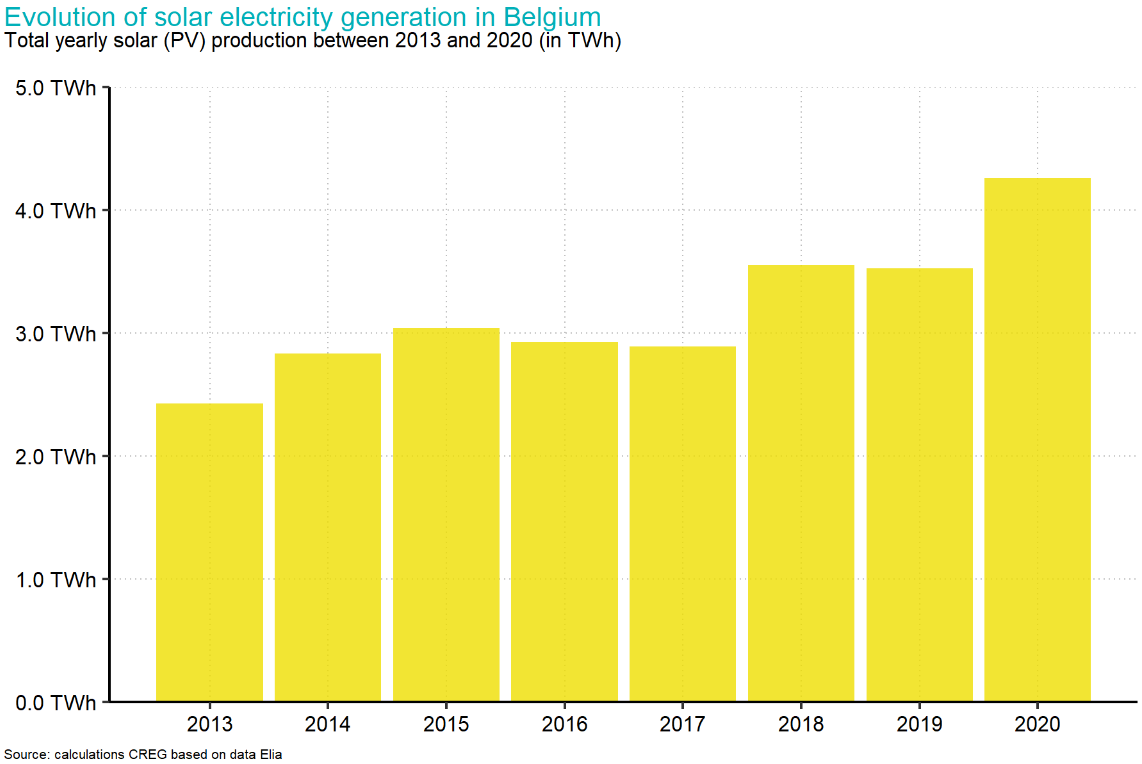


Figure 16 Evolution of solar electricity generation in Belgium

35. As illustrated on Figure 16, solar electricity generation has been considerably increasing since 2013 to reach 4,3 TWh in 2020. This represents an increase in electricity generation from solar panels by 80% compared to 2013 (2,4 TWh). The development of solar panels throughout Belgium, in particular from 2018 as illustrated in Figure 10, has been supporting this rise in solar electricity generation. Bad sunlight conditions can explain the small decrease in solar electricity generation in 2016 and 2017.

2.4. CAPACITY FACTOR

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

37. As far as renewable energy sources (RES) are concerned, biomass is the technology with the highest capacity factor (41% in 2020) despite a noticeable decrease by 10 percentage points between 2017 and 2020. This can be explained by a lower utilisation rate of biomass-fired power plants due to the growth of other renewable energy sources (solar and wind).

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 (35% and 19% in 2020, respectively). Solar and hydro run-of-river are the

[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 2020, we computed the 2019-2020 average installed capacity and used it as input data to calculate the capacity factor in 2020.

technologies with the lowest capacity factor. Indeed, solar panels can only produce electricity during daytime while hydro run-of-river is subject to seasonal river flows and thus operates as an intermittent energy source.

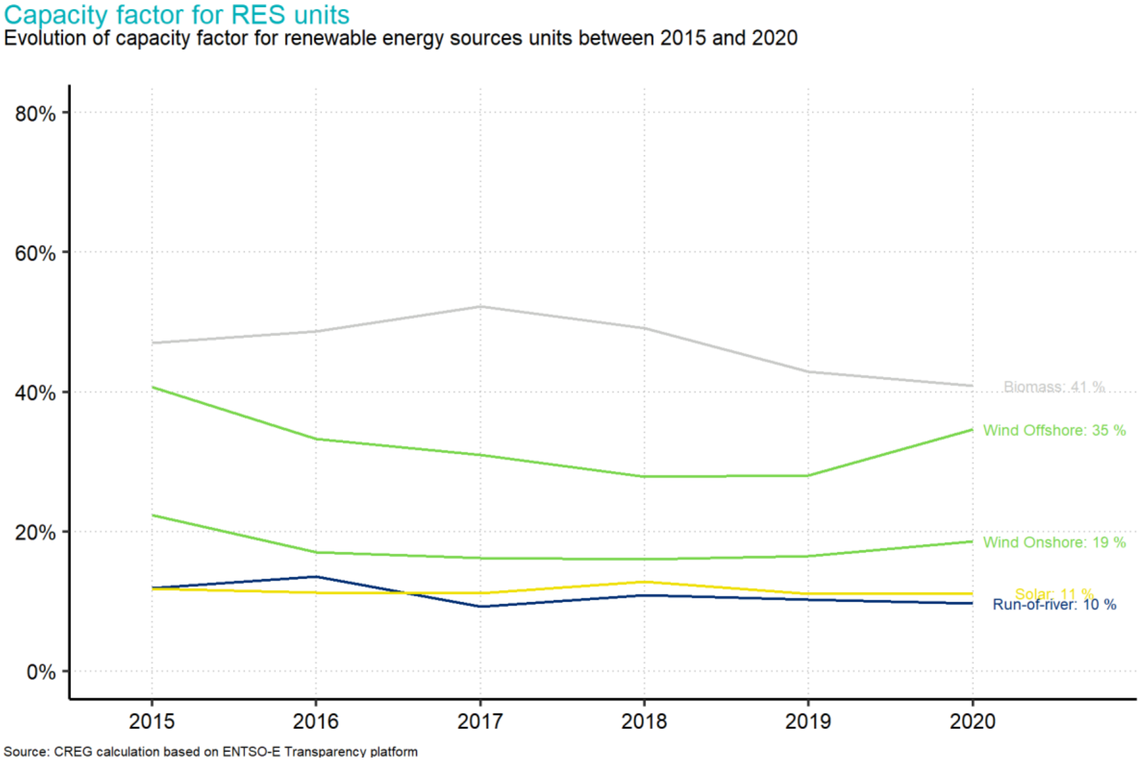


Figure 17 Capacity factor for RES plants

39. The capacity factor of hydro pumped storage (non-RES intermittent) fluctuates around 20% between 2015 and 2020, illustrating the fact that these plants notably provide load balancing services and thus do not produce electricity continuously.[7]

40. As far as conventional generation is concerned, waste and nuclear are the technologies with the highest capacity factor. The capacity factor of nuclear fluctuates considerably between 2015 and 2020 (48%-80%), reflecting the high unavailability rate of nuclear power plants in 2015 and 2018 as well as limited power demand in 2020 due to the COVID-19 crisis.

41. The capacity factor of gas-fired power plants remained stable just below 40% during that period. One can notice that the capacity factor of gas power plants did not increase in 2015 and 2018 despite the limited availability of nuclear power plants at that time in Belgium. As already explained in previous monitoring reports of the CREG, the shortfall of nuclear electricity generation is mostly compensated by an increase of imports.

42. Fossil oil generation capacity remains available for security of supply purposes but rarely produces electricity. Hence, the capacity factor is close to zero.

[7] At the same time, it should be noted that pumped storage can only produce at maximum capacity during roughly half of the hours, as the other hours are needed for pumping water to the basins. Hence, it should be interpreted as 20% of half a year, being 40% of an entire year.

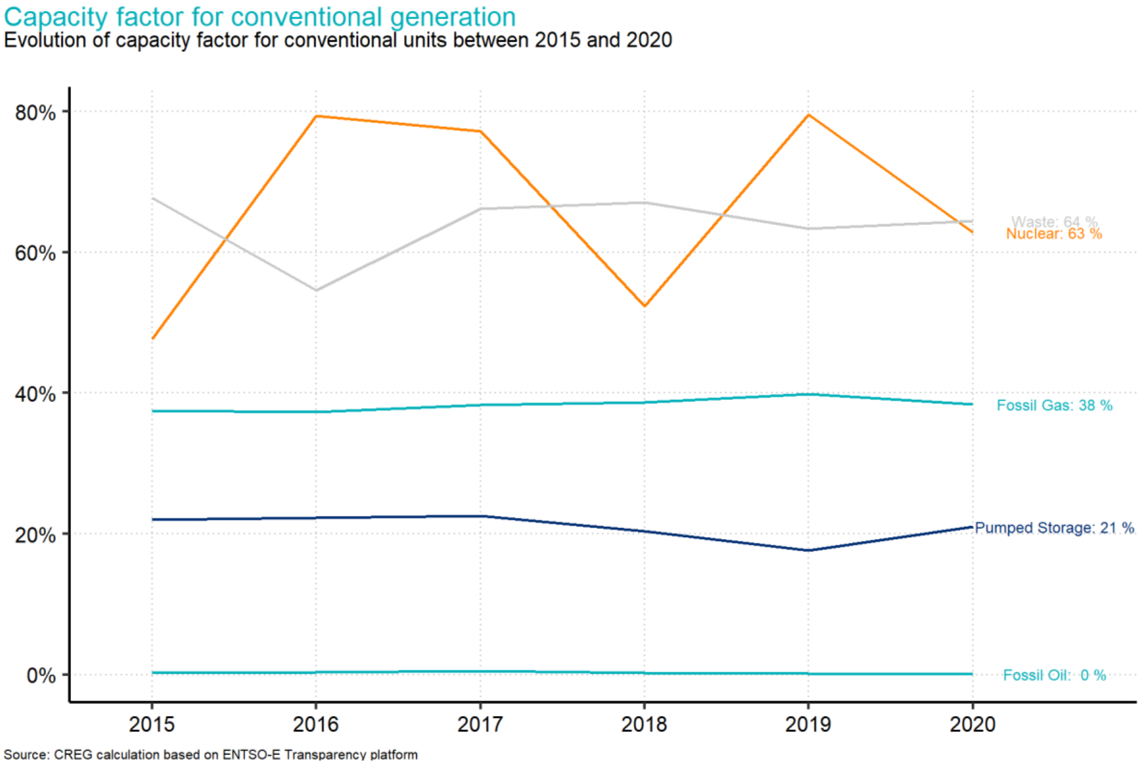


Figure 18 Capacity factor for conventional generation

2.5. CARBON INTENSITY OF ELECTRICITY GENERATION

43. Figure 19 illustrates the evolution of greenhouse gas emission intensity of electricity production in Belgium and neighbouring countries for the period 1990 – 2019. 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 $gCO_{2;eq}$/kWh in 1990 to 230 $gCO_{2;eq}$/kWh in 2019). In particular, greenhouse gas emission intensity of electricity production in the UK was divided by 2 between 2012 and 2019.

44. Belgium's greenhouse gas emission intensity decreased from 358 $gCO_{2;eq}$/kWh to 174 $gCO_{2;eq}$/kWh between 1990 and 2019, i.e. a reduction of 50%. The level of greenhouse gas emission intensity is highly dependent on the energy mix used to produce electricity. The downward trend 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 of solar and wind in the electricity production mix. Recent short surges in the carbon intensity of the production mix in Belgium were witnessed in 2015 and 2018, when the reduced nuclear availability and generation (see also Figure 14), had to be compensated by an increase in electricity generated from fossil fuel sources.

45. France and Austria are the only countries with a greenhouse gas emission intensity of electricity production below 100 $gCO_{2;eq}$/kWh (56 $gCO_{2;eq}$/kWh and 94 $gCO_{2;eq}$/kWh respectively). This can be explained by their highly decarbonised electricity generation mix, mainly based on nuclear for France and hydro for Austria.

46. Despite a considerable reduction over the 1990-2019 period, electricity production in the Netherlands and Germany remains highly carbonised. In 2019, greenhouse gas emission intensity of electricity production was as high as 390 $gCO_{2;eq}$/kWh for the Netherlands and 350 $gCO_{2;eq}$/kWh for Germany.

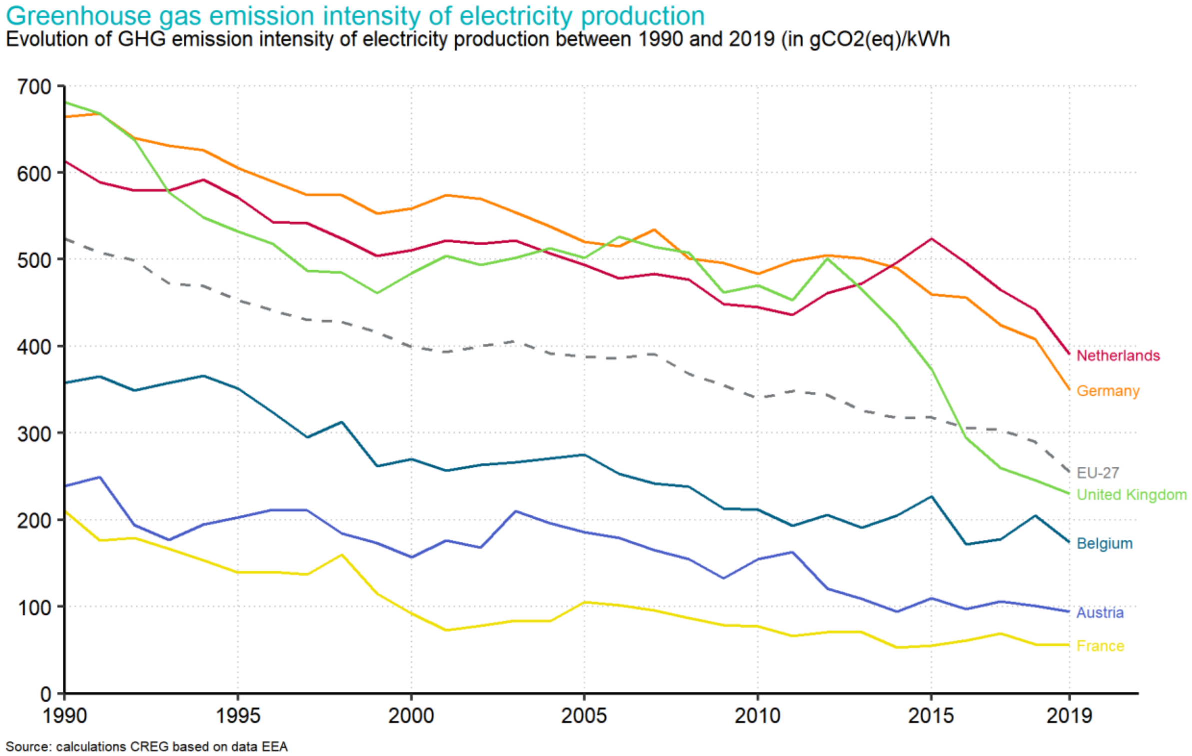


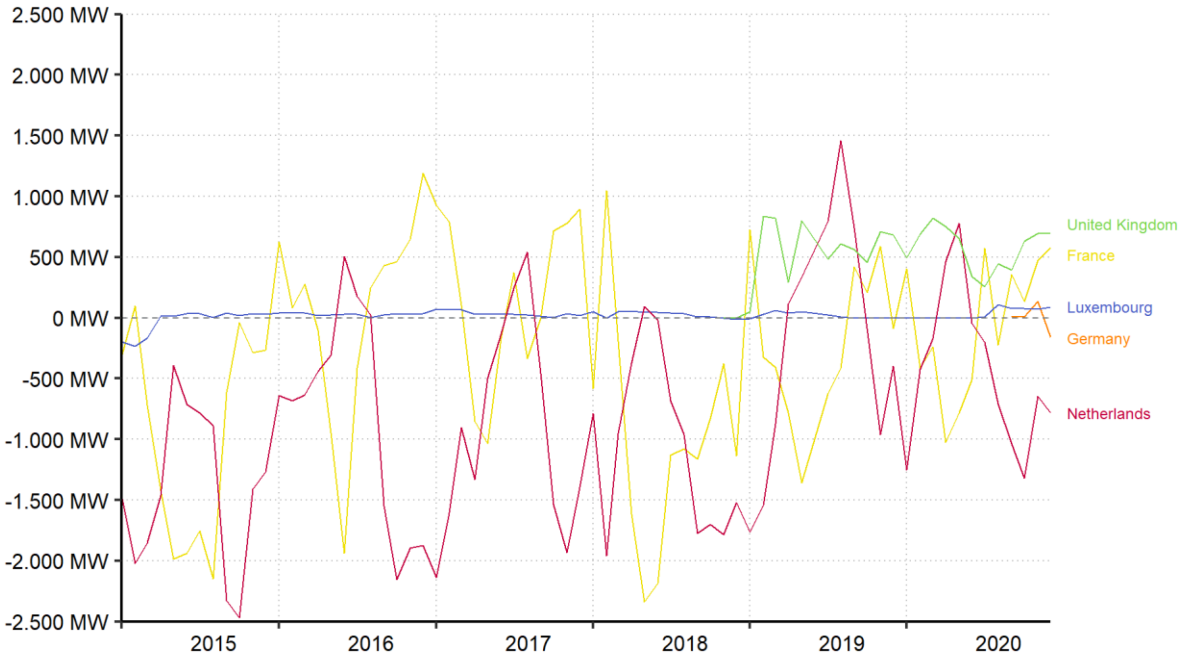
Figure 19 Greenhouse gas emission intensity of electricity production

3. CROSS-BORDER FLOWS

3.1. FLOWS PER BORDER

47. As of today, Belgium has physical interconnections with 5 other countries: France, Netherlands, Luxembourg, the United Kingdom and Germany. The HVDC connections with the UK (beginning of 2019) and Germany (end of 2020) are relatively new. The flows and net positions observed on the borders of Belgium and its neighbours are the results 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.

Physical net export flows on different borders
Evolution of monthly average physical net position on Belgian borders between 2015 and 2020



Source: calculations CREG based on data Elia

Figure 20 Physical net export flows on different borders

48. Figure 20 shows the evolution, between 2015 and 2020, of the net export flows per border, taken by subtracting the import flows from the export flows.[8] Between 2015 and 2018, an alternating pattern between import 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. Globally however, Belgium was a net importer (see also Figure 21). This (seasonal) pattern still persists in 2019 and 2020, et on average Belgium has become a net exporter of electricity.

49. 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 1.000 MW.

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

3.2. TOTAL NET POSITION

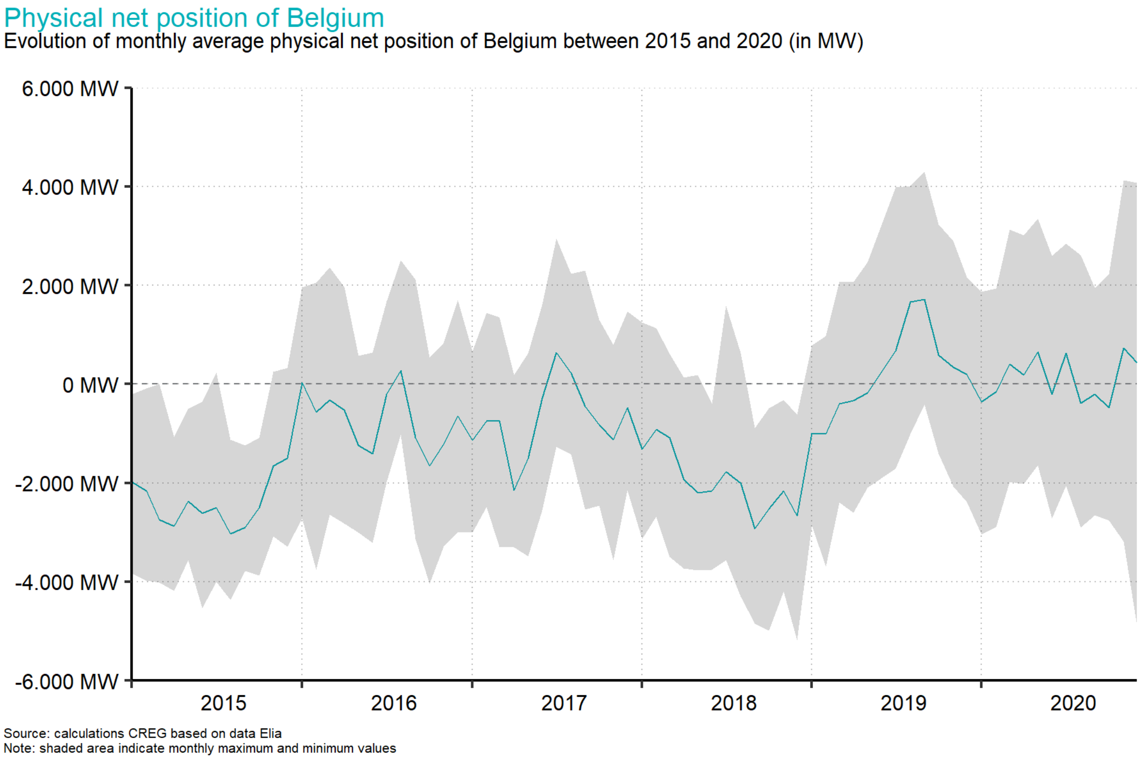


Figure 21 Physical net position of Belgium

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 21 and the annual net positions per border are listed in Table 1. The shaded area in the line graph above 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 – 5 TWh of electricity exports on a yearly basis (see Table 1);
- the decrease of electricity load (consumption) in Belgium, described in section 1.1; and
- an increase in electricity generation in 2019-2020 since 2018, as shown in Figure 13.

(in TWh)	France	Netherlands	Luxembourg	United Kingdom	Germany	**Total**
2010	2,2	-2,1	-0,7			**-0,6**
2011	-4,9	2,5	-0,2			**-2,6**
2012	-5,1	-4,3	-0,5			**-9,9**
2013	-6,3	-3,4	0,1			**-9,6**
2014	-10,3	-6,5	-2,0			**-18,8**
2015	-8,4	-12,4	-0,3			**-21,0**
2016	0,4	-6,9	0,3			**-6,2**
2017	1,6	-8,1	0,3			**-6,2**
2018	-8,6	-9,0	0,2			**-17,3**
2019	-1,5	-1,5	0,1	4,6		**1,7**
2020	-0,5	-3,9	0,3	5,0		**0,9**

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

3.3. PHYSICAL INTERCONNECTION CAPACITY

51. These physical flows of energy are accommodated by the transmission capacity on the borders with neighbouring countries. 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**	**Pmax**
Netherlands	380	Van Eyck	Maasbracht	1.439 MW
	380	Van Eyck	Maasbracht	1.316 MW
	380	Zandvliet	Borsele	1.645 MW
	380	Zandvliet	Geertruidenberg	1.645 MW
France	380	Achène	Lonny	1.316 MW
	380	Avelgem	Mastaing	1.316 MW
	380	Alvegem	Avelin	1.528 MW
	220	Aubange	Moulaine	442 MW
	220	Aubange	Moulaine	442 MW
	220	Monceau	Chooz	400 MW
TOTAL AC				**11.489 MW**
Germany (ALEGrO - DC)	380	Lixhe	Oberzier	1.000 MW
United Kingdom (Nemo Link - DC)	400	Herdersbrug	Richborough	1.000 MW
TOTAL DC				**2.000 MW**

Table 2 Installed transmission capacity connecting to neighbouring countries

4. LONG-TERM MARKETS

52. Trading of electricity in Belgium may take place in long-term markets. There are standardised long-term (futures) markets (organised by power exchanges) and unstandardised forward markets (*"Over – the – counter"* or OTC). Market players generally participate in these markets to hedge against (differences between) short-term electricity prices.

53. In this chapter, the yearly and monthly forward 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 neighbouring countries such as France, the Netherlands and – more recently – Great-Britain and Germany).

4.1. FUTURES MARKETS FOR DELIVERY IN BELGIUM

54. Trading in power derivatives, such as long-term futures contracts, can take place with physical delivery of the traded energy 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.

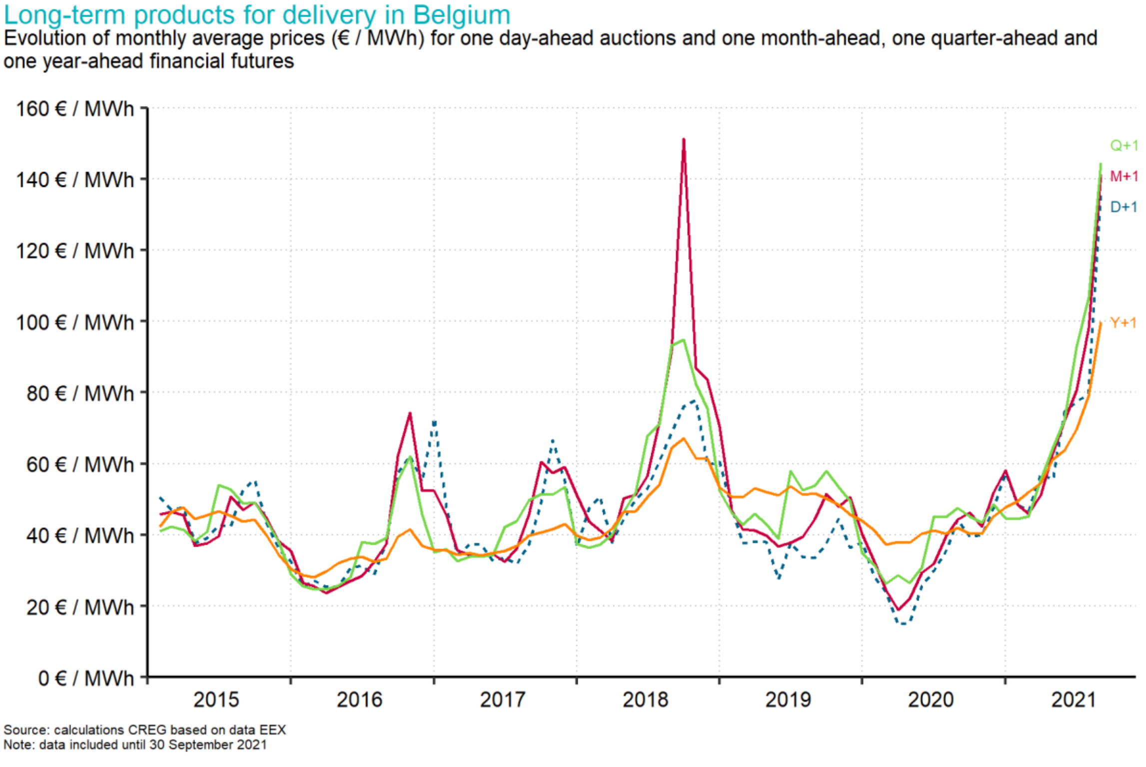


Figure 22 Long-term products for delivery in Belgium

55. Figure 22 shows the monthly averages of the different futures contracts (one month-ahead, one quarter-ahead and one year-ahead) and the monthly average of the day-ahead quotes. When a one year-ahead futures contract lists higher than the day-ahead price on contract date, it implies that on average, market participants anticipate that prices will increase, during the corresponding contract period, compared to today's quotation in the spot market. As an example, the extremely low-day ahead prices following the lockdown in April – May 2020 were reflected more highly in the one month-ahead and one quarter-ahead prices, than in the one year-ahead prices, suggesting that generally, the

market believed that this reduction was (partially) temporary. Compared to the day-ahead, one month-ahead and one-quarter ahead prices between 20 and 30 € / MWh, market participants were ready to pay 40 € / MWh for a delivery in 2021 indicating an expectation of market participants of future price increases in the spot markets in 2021 in comparison with the period between April and May 2020.

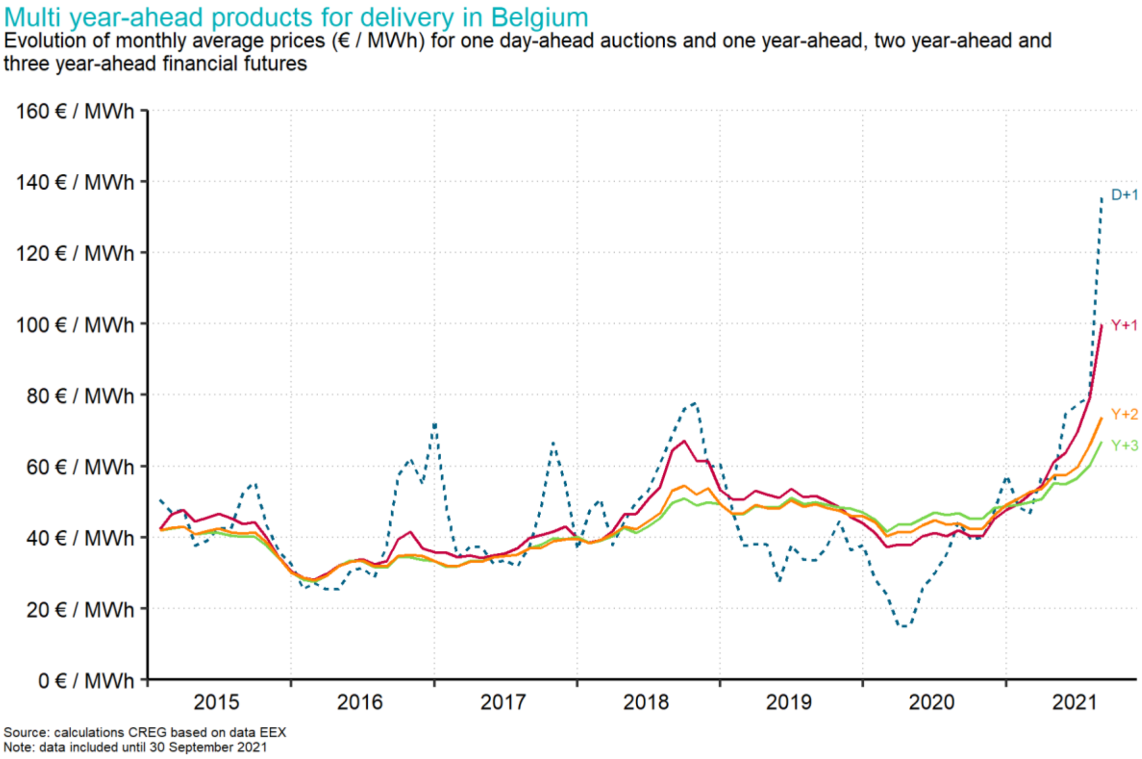


Figure 23 Multi year-ahead products for delivery in Belgium

56. Similarly, prices for two- and three year-ahead contracts may be analysed against the benchmark of the day-ahead price. This is done in Figure 23, where the time series for the one year-ahead, two year-ahead and three-year ahead contracts are shown. As before, these generally follow the up- and downward fluctuations of the spot markets, yet flattening out the up- and downward spikes. Over the course of 2019 and 2020, yearly products traded at a significant premium over the day-ahead auctions, indicating an expectation of market participants of future price increases in the spot markets.

57. Figure 22 and Figure 23 only compare prices on the same date of the contract, yet these cover different delivery periods. They are therefore only useful to analyse the up- and downward movements of the different contracts yet they do not show how much market participants pay or receive, in general, for electricity on a certain delivery date or period. This is tackled in the next figure and table: here the different contracts are matched and compared on the delivery date.

Price differentials between futures contracts and day-ahead auctions for the same delivery period
Difference between average futures and day-ahead prices for different delivery periods (in € / MWh)

Source: calculations CREG based on data EPEX SPOT and EEX

Figure 24 Price differentials between futures contracts and day-ahead auctions for the same delivery period

58. The differences between the long-term and short-term prices per delivery period in Belgium are summarized in Figure 24. This figure shows, in red, positive price differentials (where the relevant long-term contracts trade at a premium to the spot market) and, in blue, negative price differentials (where the relevant long-term contracts trade at a discount to the spot market).[9]

[9] The figure needs to be interpreted as follows. For example, in the bottom left corner, the price of a futures contract for delivery in 2016 (in this case concluded in 2015 as it is a "Y+1" contract) is about 7 € / MWh higher than the average day-ahead price in 2016, indicating that a market participant is better off to buy on the day-ahead market than on the futures market.

(in € / MWh)	Delivery period				
Contract	**2016**	**2017**	**2018**	**2019**	**2020**
D+1	36,6	44,6	55,3	39,3	31,9
M+1	36,4	43,7	66,9	47,9	35,1
Q+1	33,7	42,2	53,0	57,4	39,9
Y+1	43,9	33,3	37,3	50,9	51,1

Table 3 Yearly average prices for yearly, quarterly, monthly and daily electricity products

59. Table 3 above summarizes the yearly averaged prices for each delivery period with different possible contracts (one year-ahead, one quarter-ahead, one month-ahead and day-ahead). For the delivery period 2020, average prices are 51,1 €/MWh, 39,9 €/MWh and 35,1 €/MWh for one year-ahead, one quarter-ahead and one month-ahead futures contracts respectively: this is significantly higher than the yearly averaged day-ahead price of 31,9 € /MWh.[10] For delivery in 2020, a consumer that bought its electricity indexed on the day-ahead price paid on average almost 20 €/MWh less than if it would have bought its electricity indexed on the year ahead. However, for 2021 this finding will be largely reversed, with average year ahead prices for delivery in 2021 being much lower than the average day-ahead price in 2021.

60. Through a similar calculation method as in Figure 24 and Table 3 it is possible to show futures prices for delivery in future calendar years. Figure 25 shows, for calendar years 2020 until 2024, the average price evolution from one, two and three year-ahead futures contracts. While in 2019 and 2020 these three contracts traded at similar price levels, they diverged during the summer months of 2021. Since June 2021, market participants anticipate higher prices for delivery in 2022 than in 2024. Futures contracts for delivery in 2022 traded at 120 € / MWh and higher, which are historically high numbers.

[10] The numbers in the Table 3 follow the same logic as in Figure 24 yet the delivery period is always one full year. Hence, for monthly products, the annual value published in the Table 1 corresponds to the average of the 12 prices calculated for each month of the delivery year in question. This average price is calculated for each delivery month "M" by considering the average of the daily quotations of the "one month-ahead" contracts published the month before delivery "M-1" for delivery in month "M". For example, for delivery in 2020, the price considered for January corresponds to the average of the daily quotes published in December 2019 for the "M+1" contract (for delivery in January 2020). The value published for 2020 represents the cost for a market participant to cover the entire 2020 delivery year with one-month futures contracts.

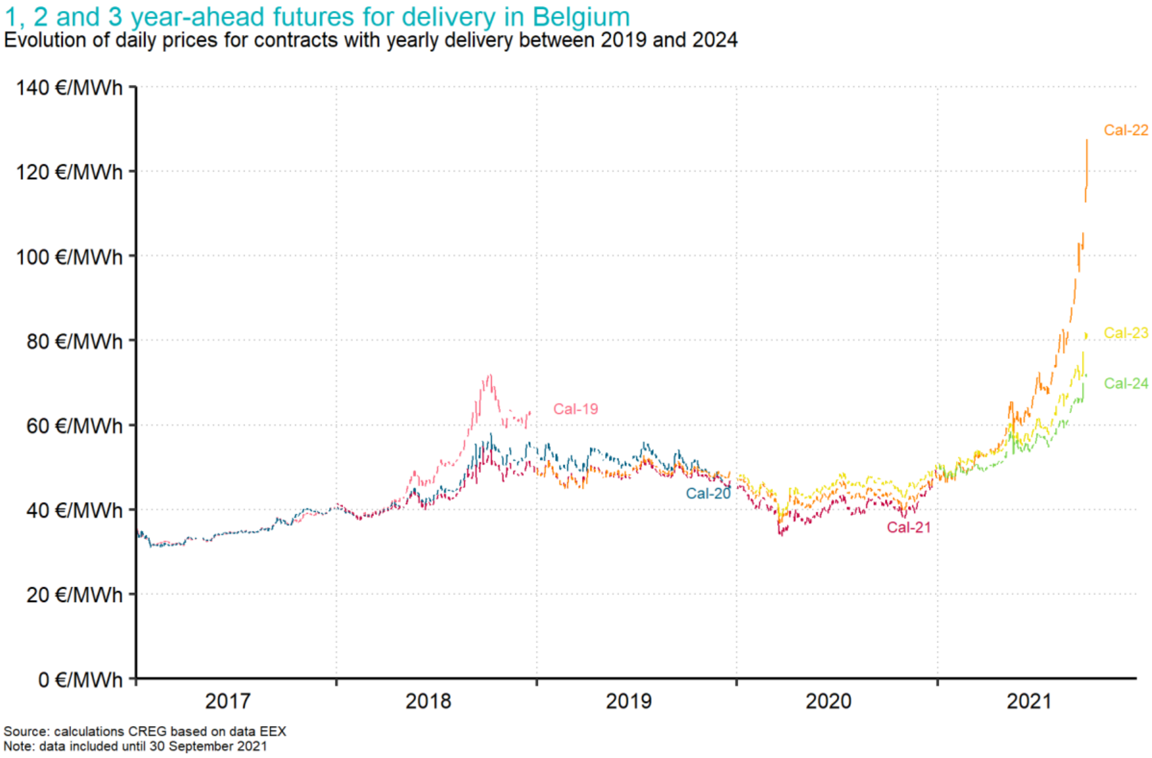


Figure 25 1-, 2- and 3 year-ahead futures for delivery in Belgium

4.2. CROSS-ZONAL LONG-TERM MARKETS

61. In order to secure access to cross-zonal transmission infrastructure in timeframes before the spot market, TSOs (including Elia) in Europe 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 energy 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 exchanges

62. This section 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 and Great-Britain on the other hand.[11] Generally, these auctions are organized and results are subsequently published in the month of November preceding the year of delivery: for example, cross-zonal capacity for delivery in 2020 was sold on JAO (the *Joint Allocation Office*) in November 2019.

[11] Given the recent go-live of the ALEGrO interconnector between Belgium and Germany in November 2020, no data for long-term auctions is available yet on the BE – GB border.

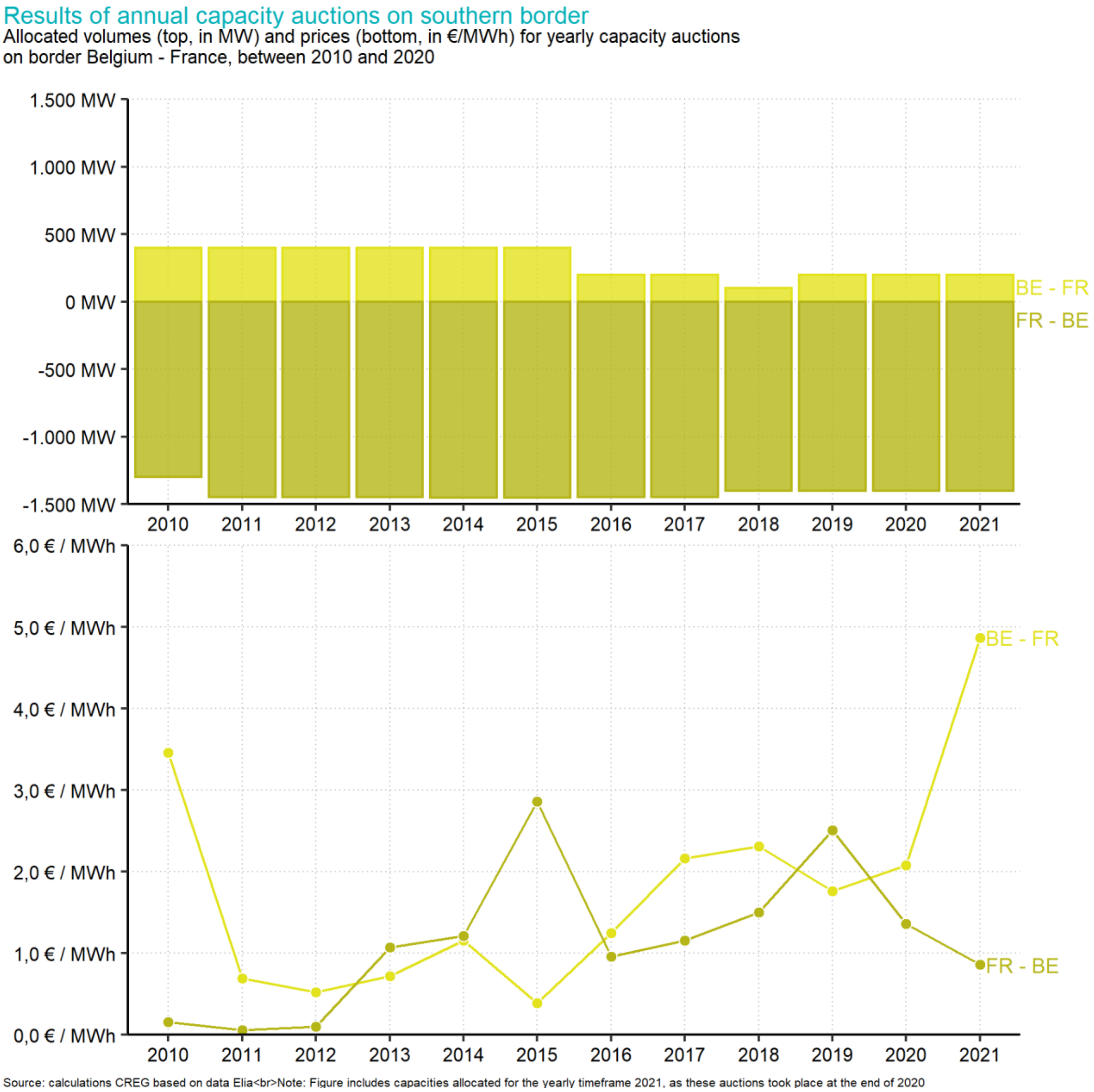


Figure 26 Results of annual capacity auctions on southern border

63. The allocated volumes for cross-zonal capacity on the southern border have historically been relatively stable in the import direction: in 2020, 1.400 MW cross-zonal capacity was available for the yearly timeframe. These values are consequently and significantly lower in the export direction, where only 200 MW was sold through the explicit auctions. The allocated volumes between 2010 and 2020 (including the 2021 timeframe) are shown in the top panel of Figure 26.

The bottom panel shows the resulting marginal price. Market participants who submitted bids at prices at least equal to the marginal price, established at the end of the auction, obtained cross-zonal capacity as a result. 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 in the relevant market time unit. For the 2020 timeframe, prices for annual cross-zonal capacity on the Belgian – French border amounted to 2,08 and 1,36 € / MWh for the export and import direction, respectively. The spread between the import and export direction further increased in the auction for 2021: 4,87 € / MWh for export capacity and 0,86 € / MWh for import capacity.

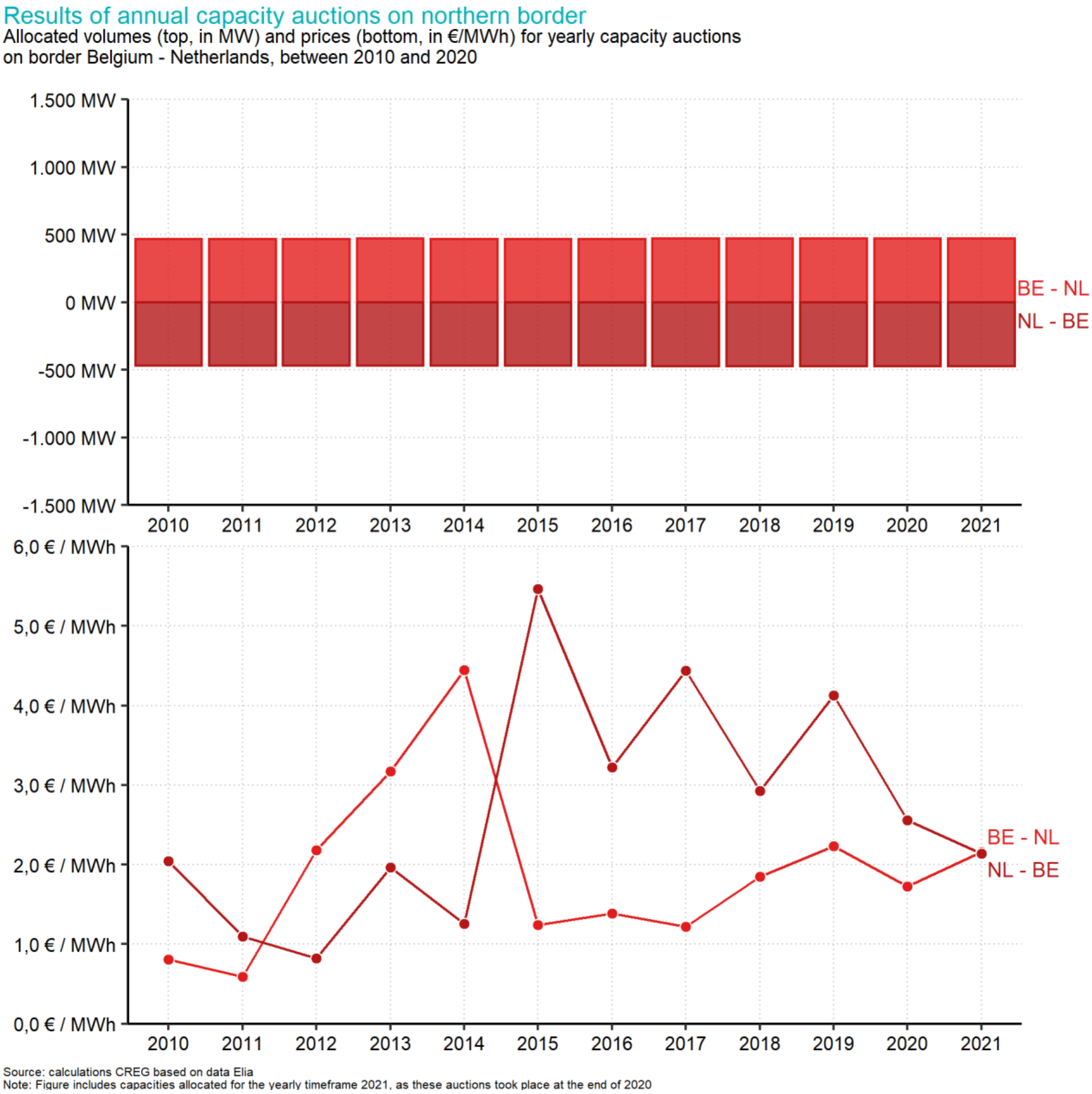


Figure 27 Results of annual capacity auctions on northern border

64. On the northern border, cross-zonal capacities are sold in a more even manner between the import and the export direction. For the 2020 timeframe, allocated capacities reached 473 MW in the export direction and 472 MW in the import direction. These values have been nearly identical since 2010.

This does not imply stable prices: as on the southern border, prices fluctuate in the range between 0,5 and 6 € / MWh. The cost of cross-zonal capacity amounted to 1,73 € / MWh for the export direction and 2,56 € / MWh for the import direction in 2020 and 2,14 € / MWh (export) or 2,16 € / MWh (import) in 2021.

These results are summarized in Figure 27 above (volumes in the top panel, prices in the bottom panel).

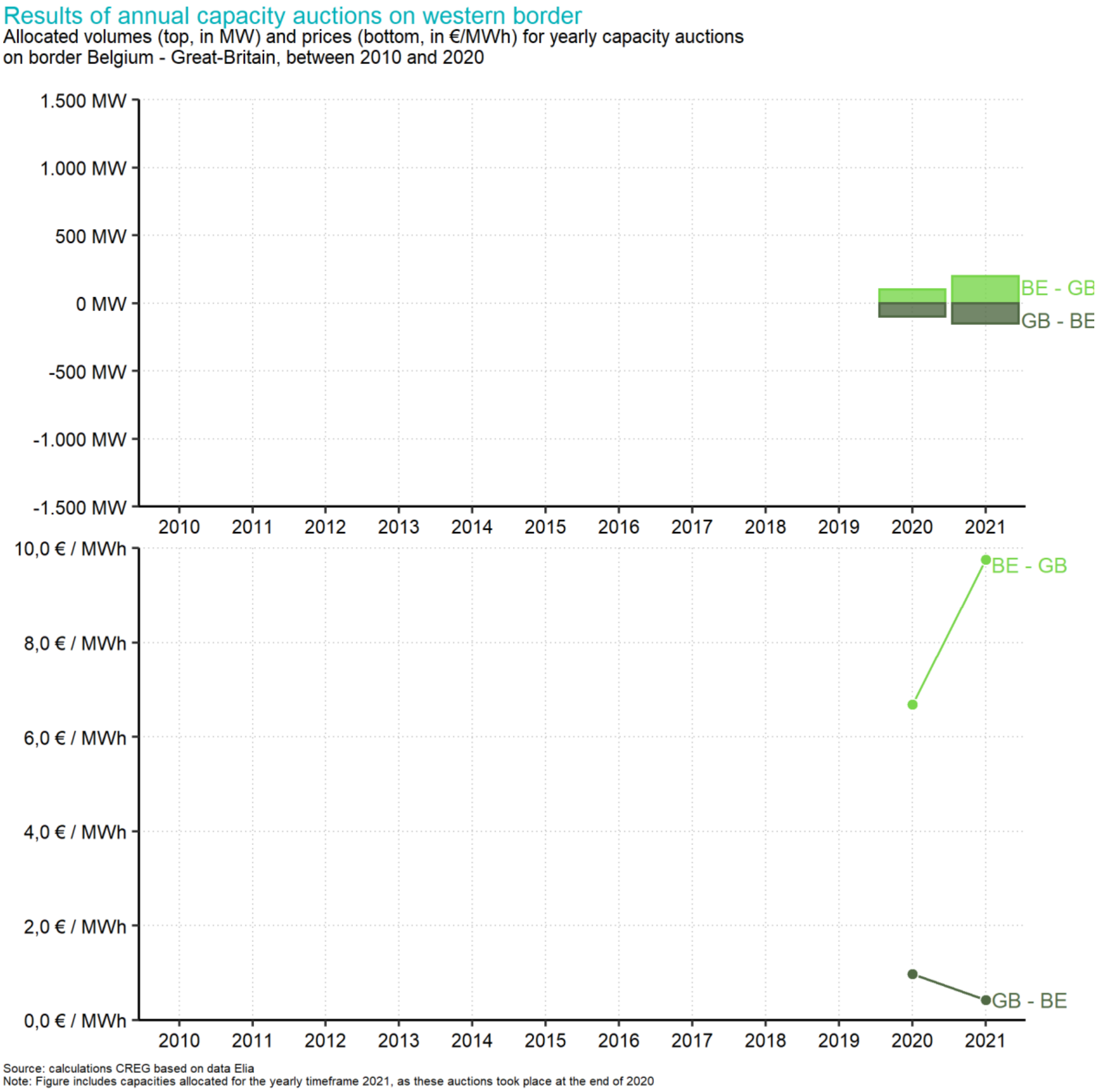


Figure 28 Results of annual capacity auctions on western border

65. On the border with Great-Britain, data for the yearly allocations is only available since the end of 2019 (auction for 2020), as the Nemo Link interconnector became operational in early 2019. The allocated capacities reached 100 MW (export) and 99 MW (import) for 2020, increasing to 200 MW (export) and 150 MW (import) for 2021.

These auctions resulted in marginal prices which were significantly higher in the export direction (6,69 € / MWh for 2020 and 9,76 € / MWh for 2021) versus the import direction (0,98 € / MWh in 2020 and 0,43 MWh in 2021).

This matches the patterns observed 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.

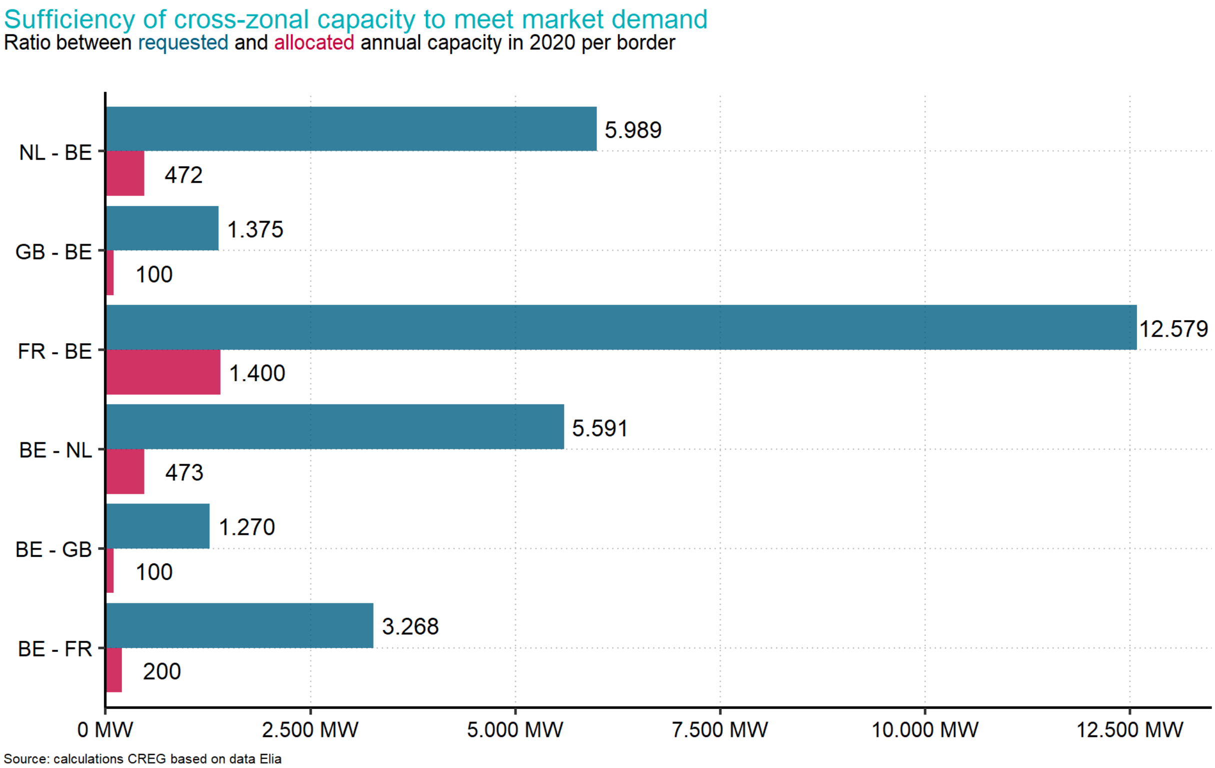


Figure 29 Sufficiency of cross-zonal capacity to meet market demand

66. Figure 29 shows, for each border and direction, the difference between the allocated and requested capacity for the 2020 yearly auctions. Generally, market participants desire to acquire much more capacity than the volume offered by Elia. Depending on the considered border and direction, requested capacity is 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.

For this reason, Figure 30 looks at the potential for market power (measured through demand-side concentration) in the annual capacity auctions.

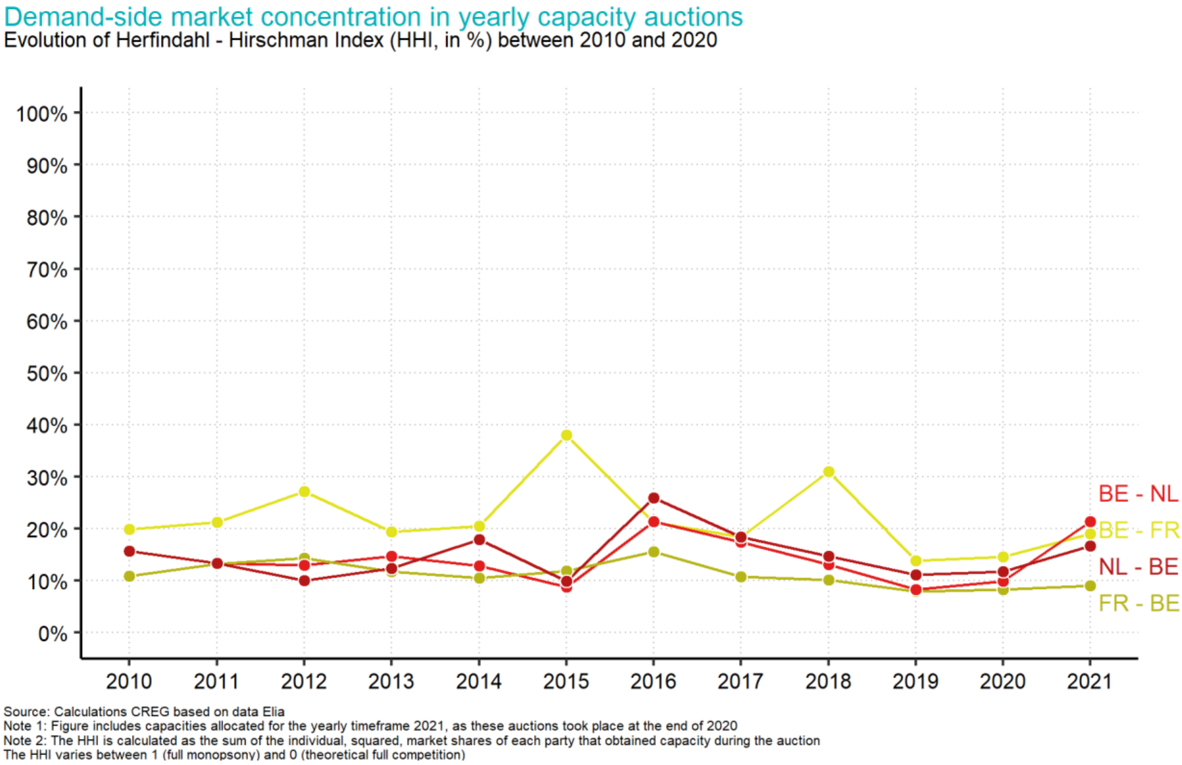


Figure 30 Demand-side market concentration in yearly capacity auctions

67. For each border and direction, the HHI is calculated and presented for the yearly timeframe in Figure 30. Generally, it can be concluded that – especially since 2019 – market demand is relatively competitive: different market participants manage to obtain a share of the offered capacity in the explicit auctions. A market is considered to be concentrated if the HHI exceeds 20%, while values of around 10% indicate a relatively equal distribution of market share between participants. Calculated values range between 10% and 20% in the last years, with an increase for the 2021 auction (especially for the import from the Netherlands).

High market concentration (as reflected in a high HHI) would, theoretically and ceteris paribus, have a downward effect on the prices for cross-zonal capacity. Of course, the price also critically depends on the value of the transmission right as a hedging instrument, and hence of the market participants' estimations of the day-ahead market spread (which sets the remuneration of the transmission rights). Therefore, the link between Figure **30** and the figures with the results of the annual auctions is less evident.

4.2.2. Monthly exchanges

68. In this section, the explicit auctions for monthly cross-zonal capacity on Belgium'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 and Great-Britain.[12]

[12] Since November 2020, the ALEGrO interconnector (forming an eastern border with Germany) came into operation. No long-term auctions were organized in 2020 and first results (allocated volumes and prices) of these will be included in a next edition of the monitoring report.

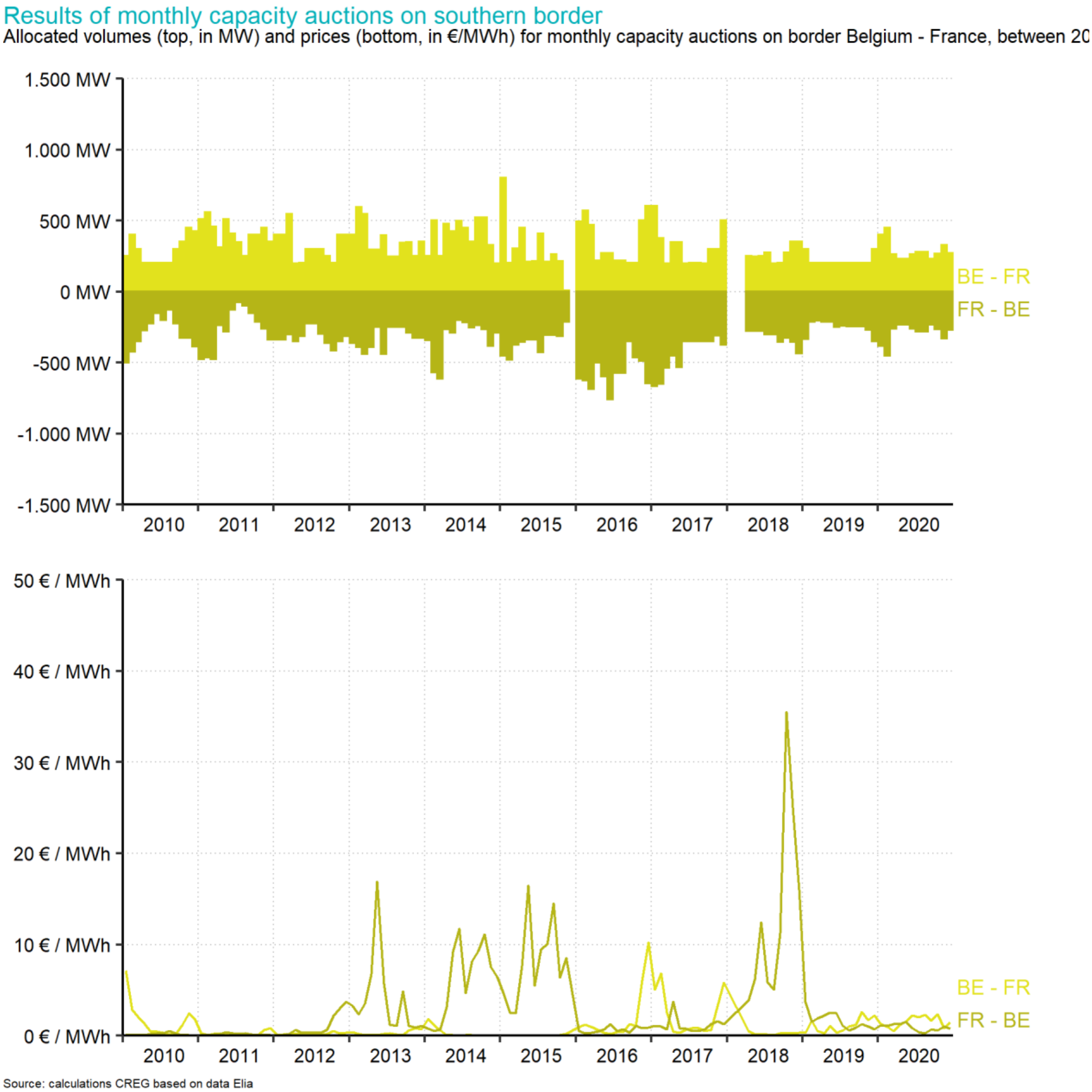


Figure 31 Results of monthly capacity auctions on southern border

69. The volumes of cross-zonal capacity auctioned in both the import and export direction from and towards France have, in 2020, varied between 200 and 450 MW. The auctioned values are identical in both directions. The resulting prices for the capacity did not exceed 4 € / MWh in either direction since early 2019. For the import direction, this represents a significant decrease from the high prices observed in the final months of 2018, where high prices in Belgium and a need for import capacity were reflected in explicit auctions resulting in prices reaching 35,5 € / MWh (in October 2018).

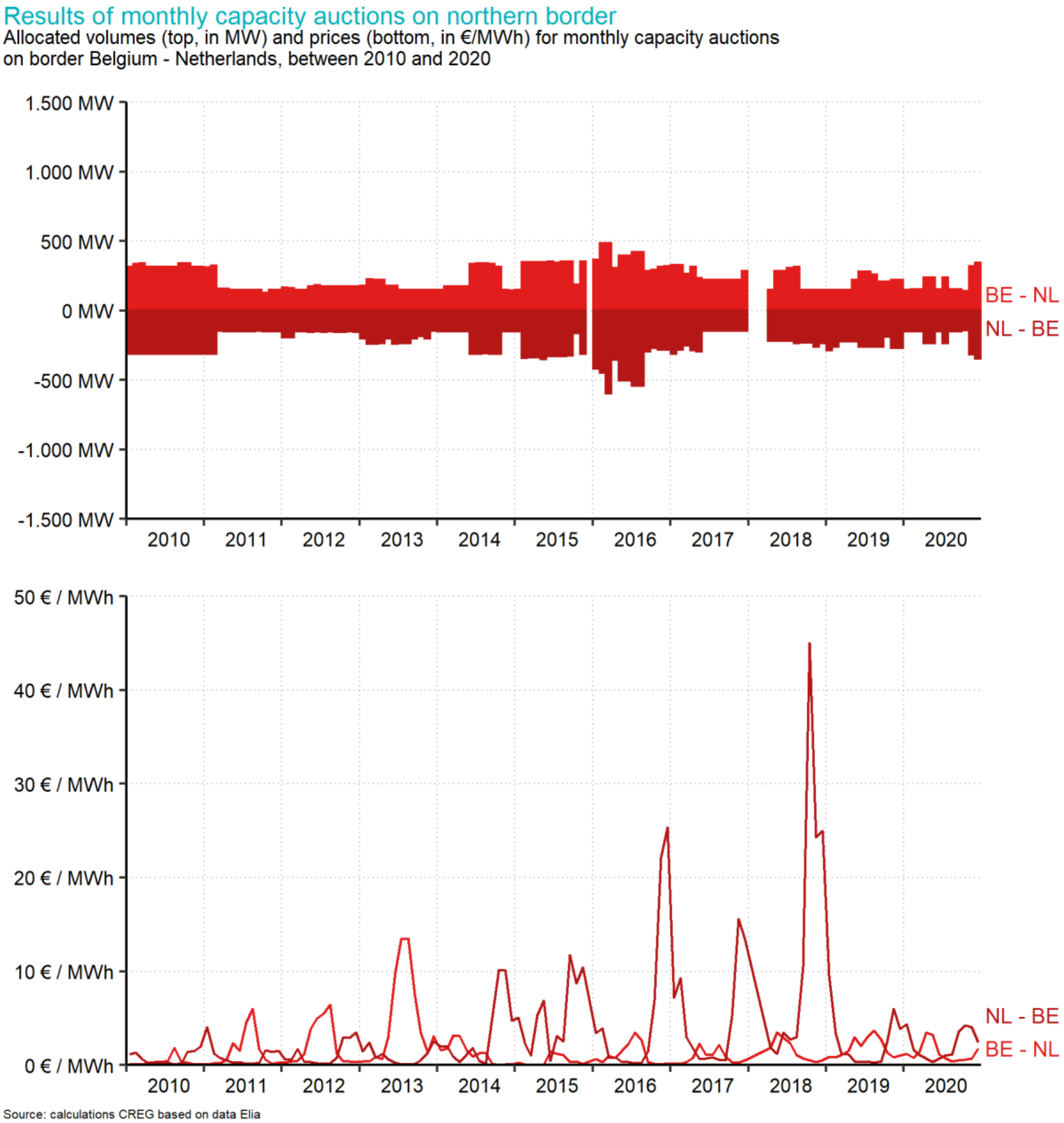


Figure 32 Results of monthly capacity auctions on northern border

70. On the northern border with the Netherlands, allocated capacities ranged between 150 and 350 MW for both directions, again in a symmetrical manner. Prices fluctuated between 0 and 5 € / MWh. As on the southern border, prices have resumed to normal levels after the sharp increase for the import direction in October 2018 (45 € / MWh).

Generally, when prices in one direction are rather high, the prices in the other direction tend towards 0: this shows that the market participants generally have a desire to trade in one direction which corresponds with their estimation of the average day-ahead price spread in the delivery period. This pattern is apparent on both the northern and the southern border.

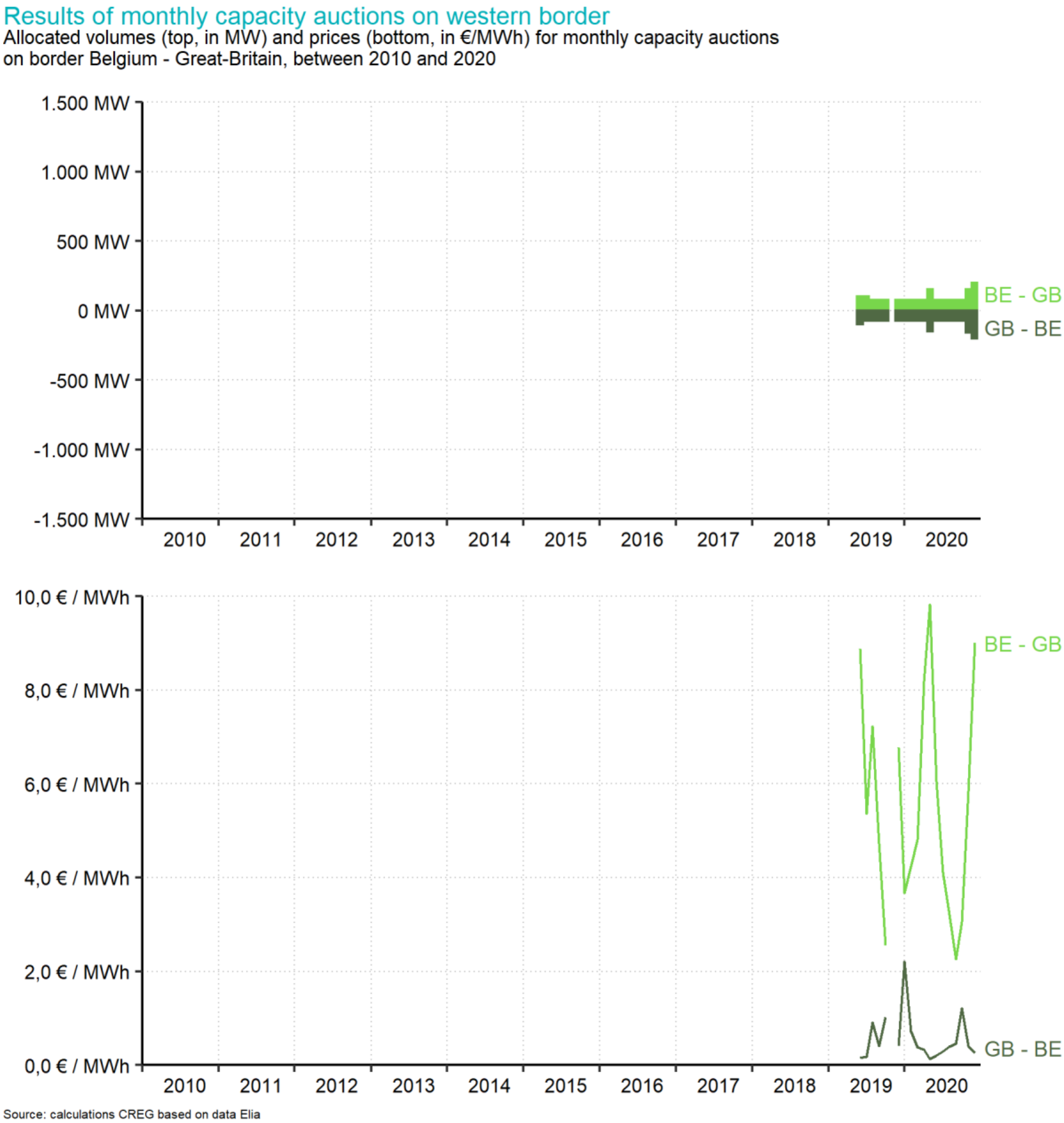


Figure 33 Results of monthly capacity auctions on western border

71. On the western border with Great-Britain, again less data is available as the first monthly auctions were organized for delivery in June 2019 only. Towards the end of 2020, a slow increase in the available allocated capacity was seen, reaching 200 MW in both directions in December. The resulting prices are low (near zero) for the import direction, while relatively high prices in the export direction are observed. This pattern reflects the observations made in the yearly auctions: market participants anticipate price differences in the day-ahead timeframe, which they wish to hedge against by obtaining cross-zonal transmission capacity.

72. Contrary to the practice on the French and Dutch borders (where Financial Transmission Rights – Options or FTR-Options are allocated), Elia sells its cross-zonal capacity, through JAO, under the form of Physical Transmission Rights with Use-It-Or-Sell-It (PTR-UIOSI) for the border Belgium – Great-Britain. This implies that the holder of the capacity has the right to nominate electricity exchanges before a certain deadline, generally one day-ahead of delivery. The non-nominated capacity is returned to the day-ahead market and the holder of the PTR-UIOSI is reimbursed the day-ahead market spread. [13] In 2020, with very few exceptions, near to 0% of the allocated cross-zonal capacity on the Belgian – Great-Britain border has been nominated.[14]

[13] Holders of FTR-Options cannot nominate physically their exchanges as this is a purely financial instrument. The total volume of FTR-Options are returned to the day-ahead market and holders of these capacities are reimbursed for the total volume at the day-ahead market spread.

[14] This is expected to change drastically in 2021, as the allocation regime changed significantly in light of the Brexit on 1 January 2021 – the CREG will report on this in the next edition of the Market Report.

5. DAY-AHEAD MARKETS

74. In Belgium, trading in the short-term (day-ahead) takes place in a market coupled with other European countries. 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 coupling algorithm *Euphemia*, calculates prices and net positions of all participating bidding zones in a single optimization round.

75. 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).[15]

76. In the day-ahead timeframe the Belgian bidding zone is coupled to its neighbours the Netherlands, France and Germany through the Central-Western Europe Flow-Based Market Coupling (CWE FBMC) and to Great-Britain through a coordinated Net Transfer Capacity approach (cNTC).

77. This chapter presents the main evolution in the coupled day-ahead markets, including both the exchanges within the CWE region as well as with Great-Britain.

5.1. EXCHANGED VOLUMES

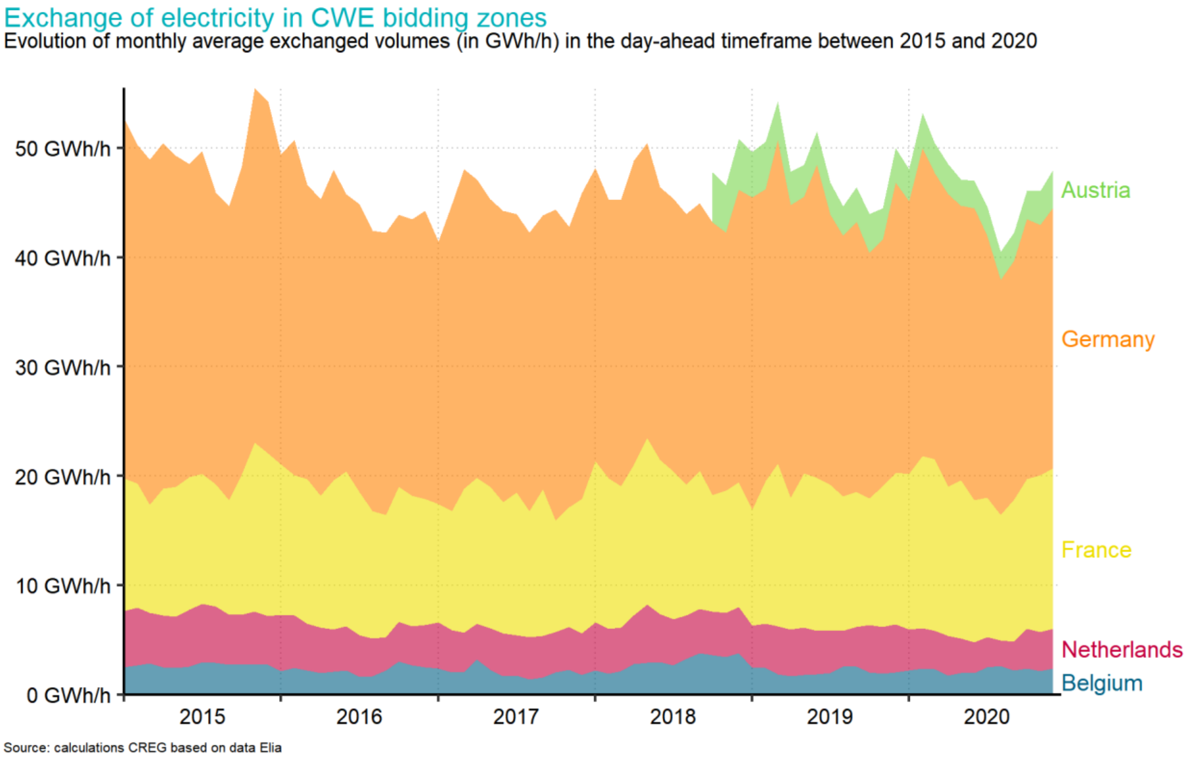


Figure 34 Exchange of electricity in CWE bidding zones

[15] Due to the unavailability of reliable data, the analyses and figures below are based on data reported by EPEX SPOT. In the next edition of the Market Monitoring Report (to be published in the first half of 2022), CREG will include analyses based on Nord Pool's data as well.

78. On average, between 40 to 50 GWh/h is traded in CWE bidding zones: the large majority of this is trade within Germany (52,6% of total in 2020) and France (29,7% of total in 2020) or with their neighbours (within our outside of the CWE region). At the same time, the share of exchanged energy in CWE's total in 2020 for Belgium only amounted to 4,8%.

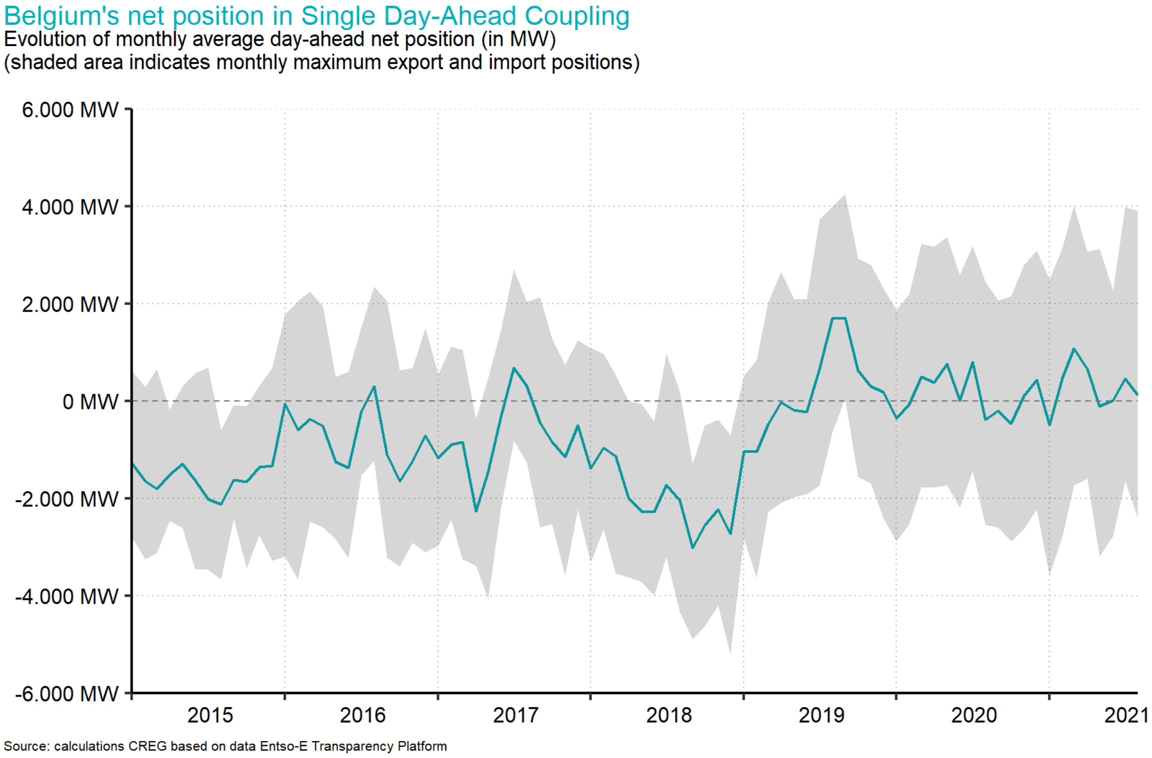


Figure 35 Belgium's net position in Single Day-Ahead Coupling

79. Once the order books of the different NEMOs in Belgium are anonymized, collected and aggregated, the day-ahead market coupling algorithm *Euphemia* calculates the resulting prices (cf. infra) and net position per participating bidding zone. The evolution of the net position resulting from this implicit coupling process is shown in Figure 35. This net position includes direct exchanges with France, the Netherlands, Great-Britain since January 2019[16] and Germany since November 2020.[17] Belgium reached its highest day-ahead importing net position on 26 December 2018 with 5.196 MW. The highest exporting net position was reached on 27 September 2019: 4.262 MW.

(in MW)	2015	2016	2017	2018	2019	2020
Average net position	-1.609	-731	-738	-2.031	190	123
Maximum net position	683	2.348	2.702	1.084	4.262	3.357
Minimum net position	-3.656	-3.668	-4.069	-5.196	-3.631	-2.892

Table 4 Evolution of yearly average, maximum and minimum net position in SDAC

80. After several years where Belgium was a structural net importer (between 2015 and 2018) in the day-ahead timeframe, this picture has changed somewhat in recent years, as is illustrated in Table 4. After 2018, where on average 2.031 MW was imported for each hour of the year, the yearly average net position became slightly positive (indicating net export) in 2019 (190 MW) and 2020 (123 MW).

[16] Following the end of the *Brexit* transition period and the effective withdrawal of the United Kingdom from the EU on 1 January 2021, the Great Britain bidding zone no longer participates to the SDAC. Hence, from 2021 onwards, the net position in the SDAC no longer includes exchanges between Belgium and Great Britain.

[17] Indirect exchanges with Great-Britain and Germany were also possible, through the market coupling of adjacent bidding zones, before January 2019 and November 2020, respectively.

The highest observed export position also increased strongly since 2015, while the highest observed import position decreased. This corresponds to the more general observation about Belgium's net position based on physical cross-border flows, as explained in section 3.2.

81. One of the reasons which explain that Belgium became a net exporter in the day-ahead timeframe, is the connection to the Great-Britain bidding zone via the Nemo Link interconnector in January 2019. Day-ahead electricity prices being – on average – higher than Belgian (see also Figure 36), Belgium is typically exporting electricity. In 2020, average day-ahead export to Great-Britain reached 706 MW. In contrast, Belgium remained even in 2020 a net importer in the CWE region, averaging a net import position of 829 MW.

5.2. DAY-AHEAD PRICES

82. This section explores several aspects related to the day-ahead prices for electricity. The importance of the (day-ahead) electricity prices should not be underestimated: in a liberalized market, the prices tend to reflect all available information and it is therefore used as a metric to steer investments and for decision-making by all market participants.

In the next subsections, the general evolution, distribution, convergence and drivers for the day-ahead electricity price in Belgium and its neighbouring countries are presented.

5.2.1. Evolution of day-ahead price

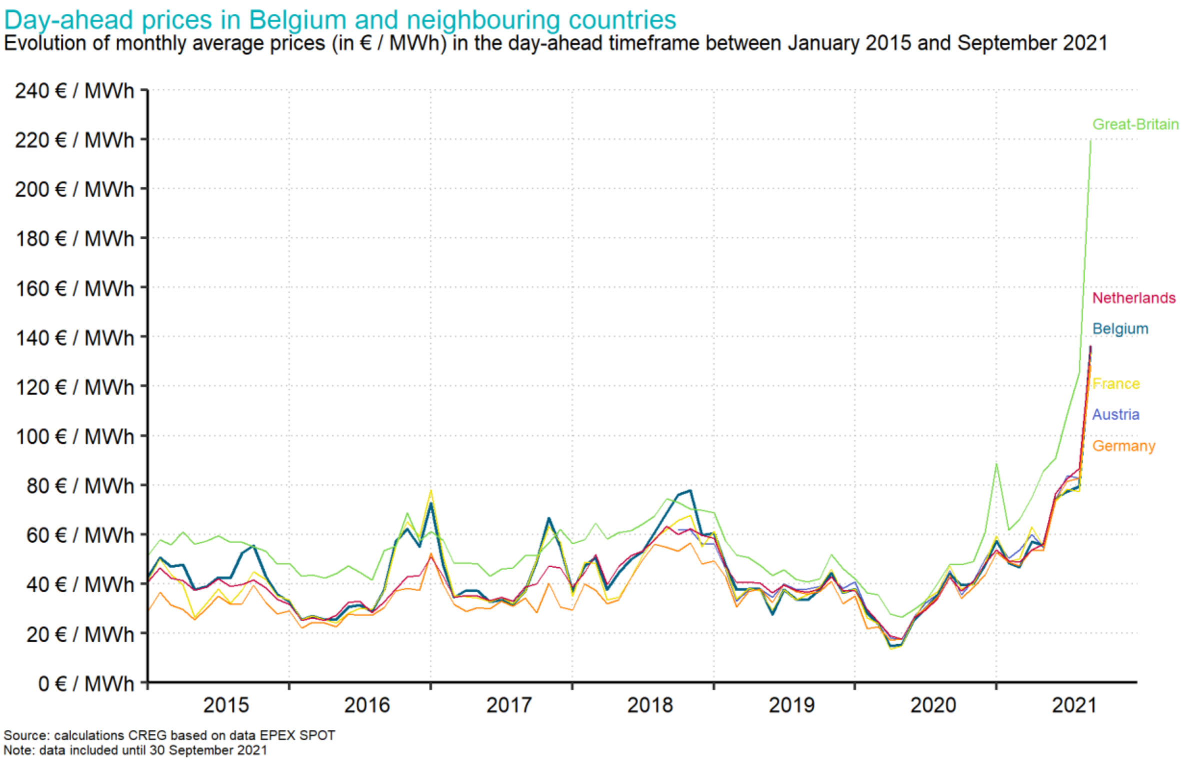


Figure 36 Day-ahead prices in Belgium and neighbouring countries

83. Day-ahead prices reached all-time low average value in 2020. This is the result of the interplay between several factors: the significant decrease in demand for electricity (chapter 1) and the low prices for commodities which are known drivers of the day-ahead price (section 5.2.3). These effects were most pronounced in April and May of 2020, following the measures in Belgium – and its

neighbouring countries – in response to the COVID-19 pandemic. In the second half of 2020, day-ahead prices resumed to relatively normal levels in light of historical trends.

84. While this report focuses on the evolutions in 2020 and 2019, market fundamentals have changed significantly in 2021, leading to a very sharp increase in average and absolute day-ahead prices in all observed countries. This observation is not restricted to spot markets: the figures in section 4.1 clearly show the market participants' anticipations that these prices increases will continue beyond 2021, as reflected in the prices for Y+1, Y+2 and Y+3 (delivery in 2022, 2023 or 2024) are above the historical "normal" range of day-ahead prices (between 30 – 50 € / MWh).

85. Figure 36 shows the historic evolution of monthly average day-ahead prices in Belgium and neighbouring countries. Between 2015 and 2018, structural differences (in both directions) were observed between these countries' prices: most often Belgian consumers had to pay higher average prices than their counterparts in other CWE bidding zones. However, these Belgian prices were still (significantly) lower than prices in Great Britain. [18]

Since 2019, prices – mostly between CWE bidding zones – tended more and more to follow the same up- and downward movements and became very much aligned. This is reflected in the increased occurrence of price convergence (section 5.2.4) and generally indicates a more efficient functioning of the CWE FMBC and a deepening of the market integration between the participating countries.

5.2.2. Distribution of day-ahead prices

86. 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.

[18] Nevertheless, direct electricity trading between Belgium and Great Britain is only possible since the go-live of the Nemo Link interconnector, allowing Belgian electricity producers to export their electricity directly to Great Britain.

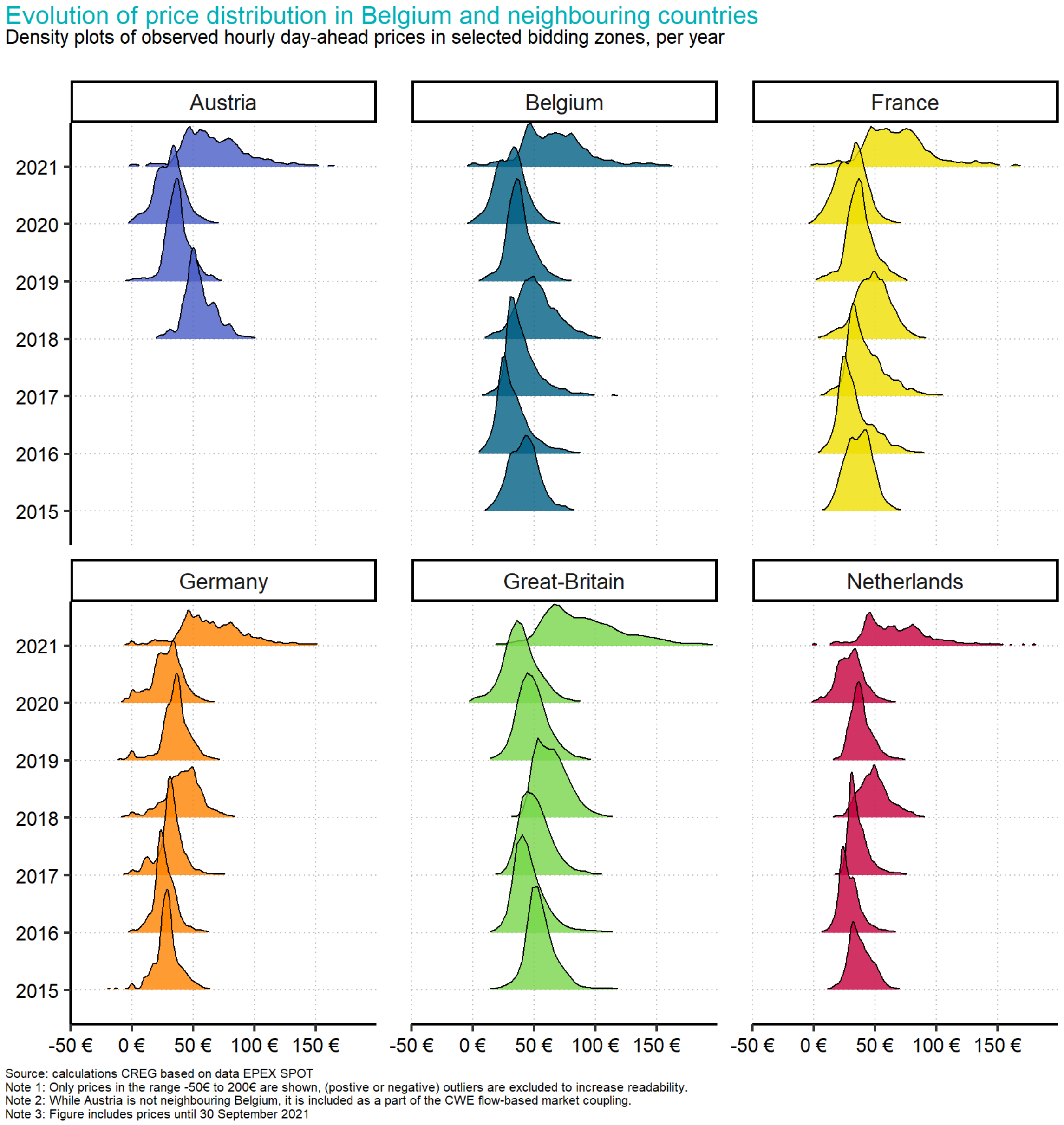


Figure 37 Evolution of price distribution in Belgium and neighbouring countries

87. The yearly distribution of the observed[19] day-ahead prices in Belgium and its neighbouring countries is shown in Figure 37. It is clear that for Belgium, but similarly other countries, the density curves shift to the left in 2019 and 2020 in comparison to preceding years. This indicate 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.

This trend has abruptly come to an end in 2021: based on the data currently available, the occurrence of low and negative prices still persists but the occurrence of (relatively) high prices (from 100 € / MWh onwards) is increasingly frequent.

[19] At least those within a normal range, as including the strongly negative and positive prices would render the figure impossible to read.

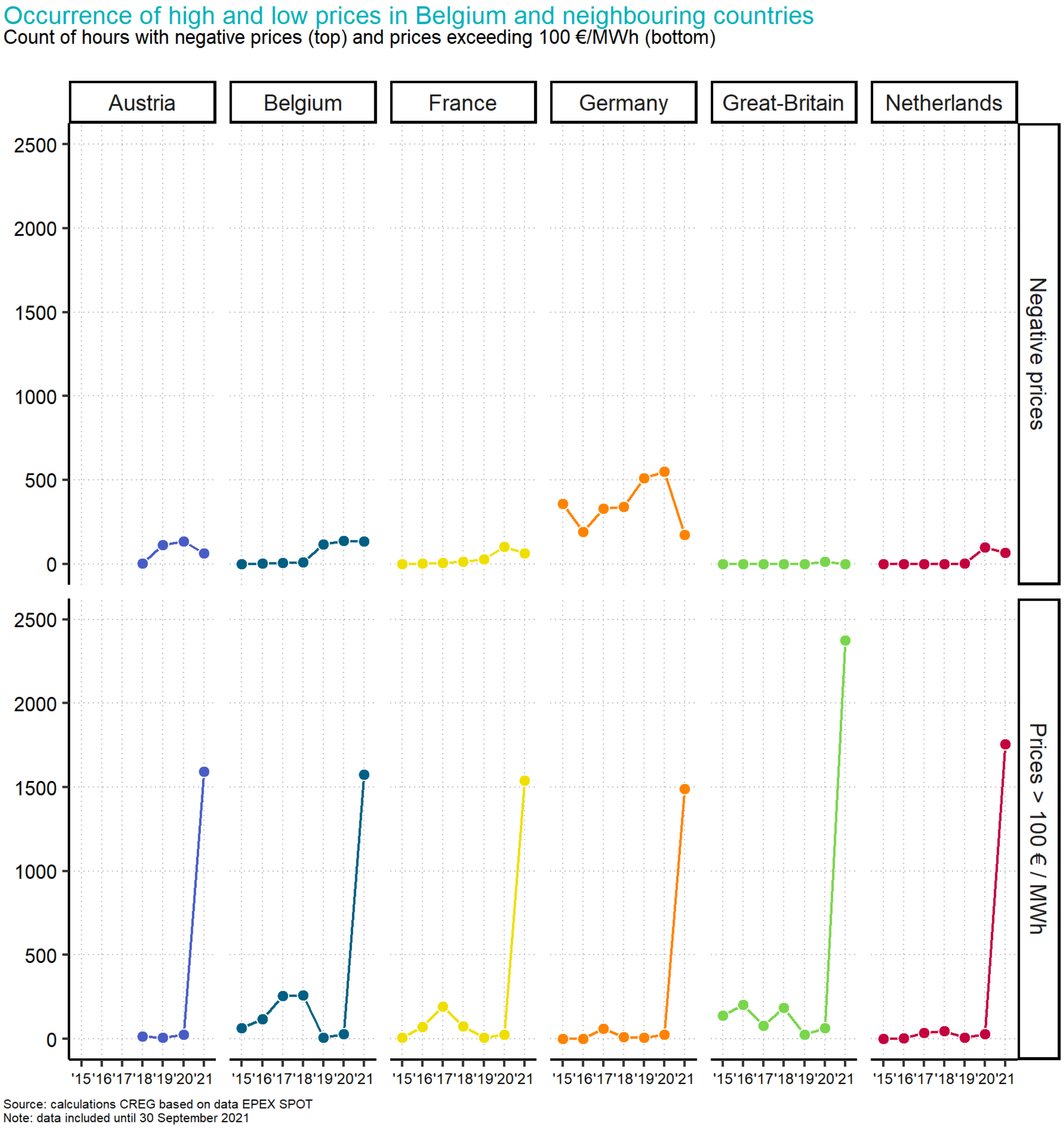


Figure 38 Occurrence of high and low prices in Belgium and neighbouring countries

88. This conclusion is supported by the count of hours in which negative and high prices (above 100 € / MWh) are observed in the different bidding zones. Belgium has seen a sharply increased occurrence of negative prices in 2019 and 2020 to 117 and 136 hours, respectively. Meanwhile, more hours with high prices were observed in 2017 (257 hours) and 2018 (258 hours).

Other interesting observations include the common occurrence of negative prices in Germany: day-ahead prices were negative during 551 hours or 6,3% of all hours in 2020.

Furthermore, the sharp increase in day-ahead prices in all European countries is well reflected in the number of hours with prices exceeding 100 € / MWh. Figure 38 shows, for Belgium, 1.574 hours (or 24,0% of the time until 30 September 2021) with such high prices. This fraction is similar for Austria, France and Germany, but higher for the Netherlands (1.757 hours or 26,8%) and Great-Britain (2.374 hours or 36,2%).

5.2.3. Drivers of day-ahead prices

89. While it is nearly impossible to accurately predict electricity prices, especially in the spot market, elements which have a more or less significant impact on increases or decreases of the day-ahead electricity prices can be identified. Some of these drivers and their impact are shown in Figure 39 (data included between January 2015 and August 2018).[20]

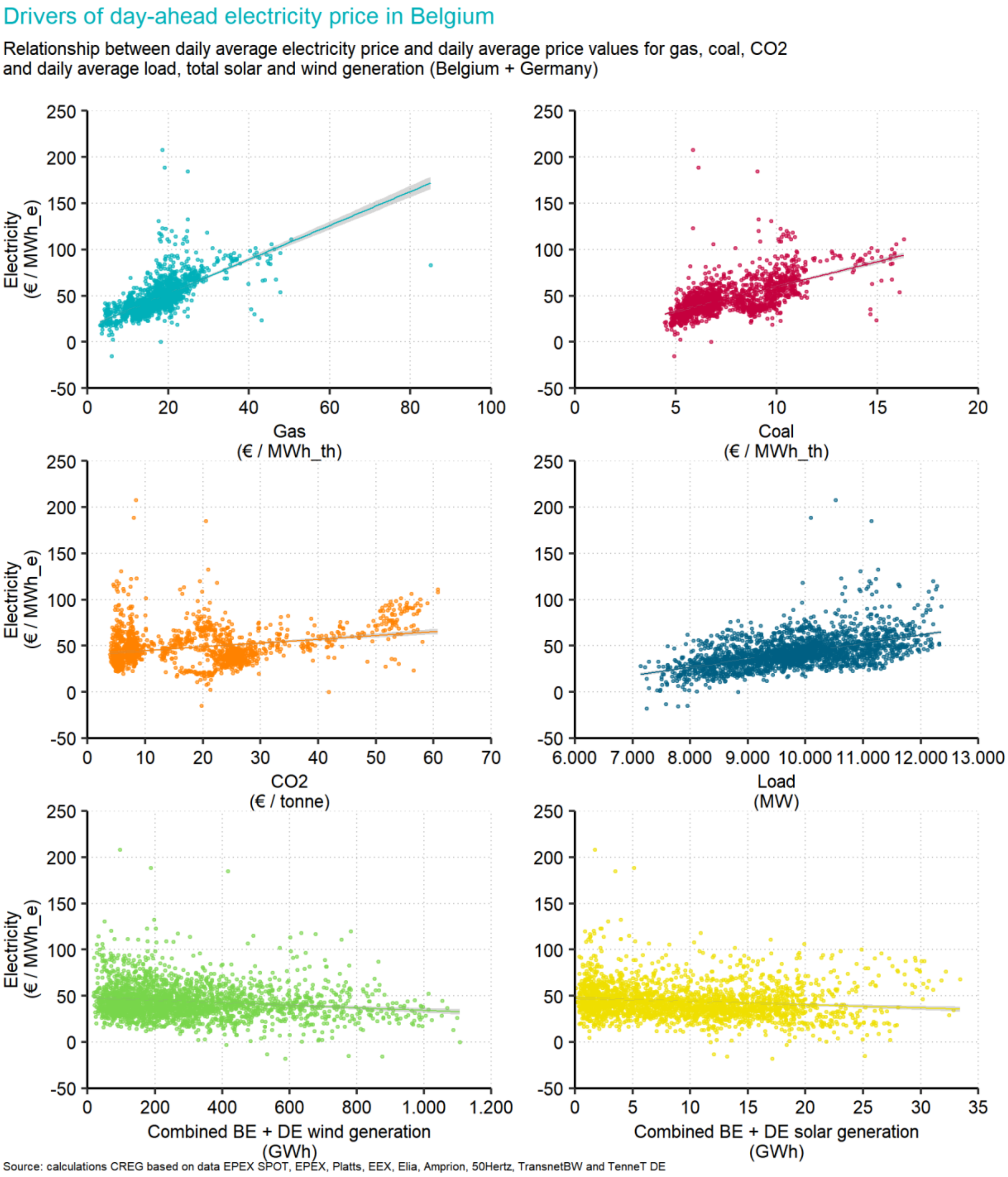


Figure 39 Drivers of day-ahead electricity price in Belgium

[20] A more in-depth analysis of the drivers of electricity prices (in light of the observed price increases in 2021) may be found in Study (F) 2289 of 24 September 2021 on the high electricity and gas prices in Belgium.

90. The relationship between the day-ahead prices for gas (TTF) and electricity is a strongly positive one. Over the observed period, an increase of the day-ahead gas price with 1 € / MWh_{th} goes hand in hand with an increase of the electricity price of 1,84 € / MWh_e. At the same time, an increase in the price for pulverized coal (which is used as input for coal burning plants) with 1 € /MWh_{th} is reflected in an increase of the electricity price with 5,39 € / MWh_e. The price for carbon allowances (EUAs under the EU Emissions Trading Scheme) also has a positive impact: when the price of CO_2 increases with 1 € / tonne, electricity prices increase with 0,41 € /MWh_e.

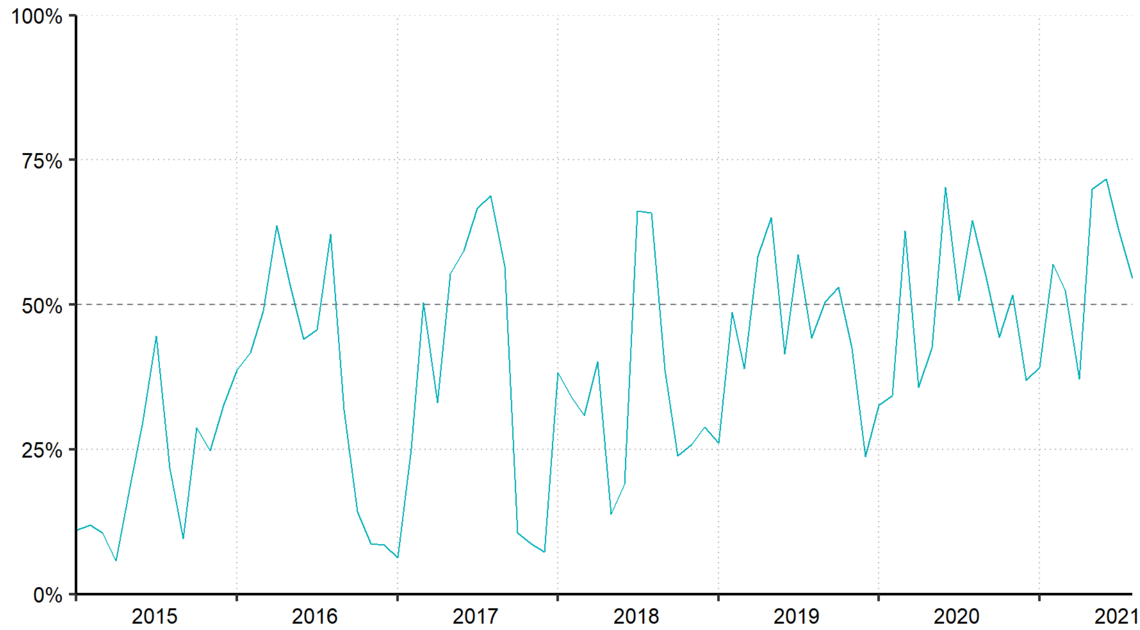
91. Wind generation, on the other hand, has a negative impact: when the total daily electricity production by wind units in Belgium and Germany (both on- and offshore) increases with 1 GWh (or on average 41,67 MWh/h of additional capacity is available on a daily basis), the day-ahead electricity price decreases with 0,01 € / MWh. To put this in perspective, in the Belgian and Germany control area, daily total wind generation fluctuated between 0 and 1.107 GWh in the observed period. For solar generation, an increase of the daily total generation with 1 GWh goes hand in hand with a decrease of the electricity price with 0,35 € / MWh.

92. Finally, electricity prices increase with an increasing consumption (measured as "total load" of the Belgian grid): an increase with 1 MW of the total average load tends to increase the day-ahead electricity price with 0,008 € / MWh.

5.2.4. Price convergence

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

Price convergence between CWE bidding zones
Evolution of monthly price convergence level between 2015 and August 2021



Source: calculations CREG based on data EPEX SPOT
Note 1: Price convergence is observed when the difference between the highest and lowest observed price is lower than 1 € / MWh
Note 2: Figure includes prices until 31 August 2021

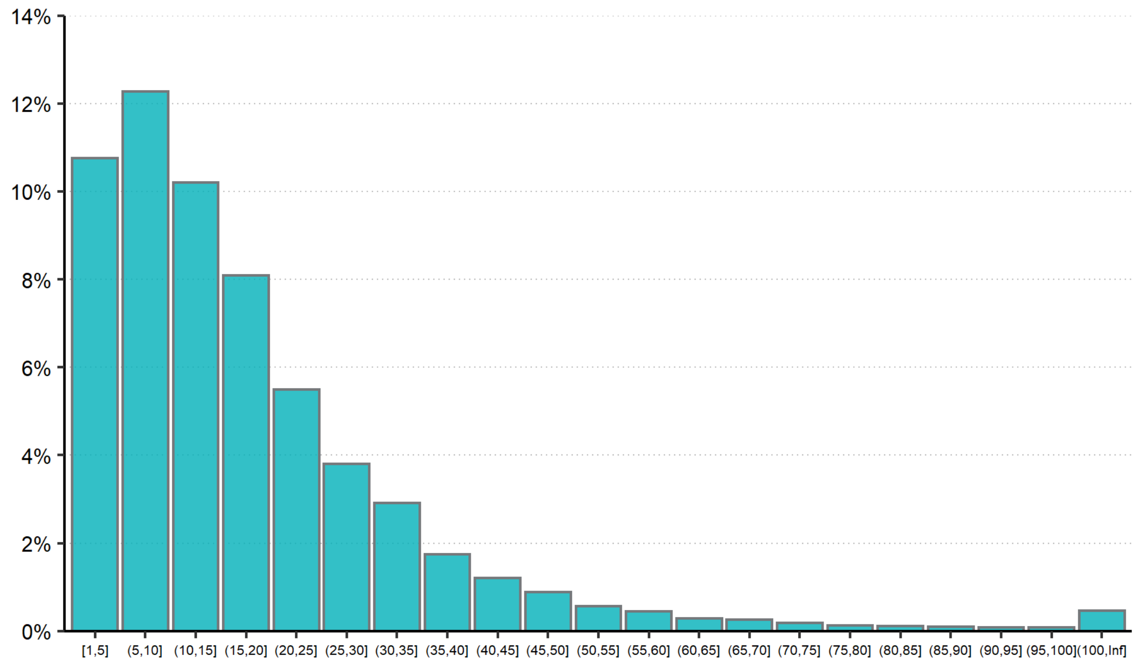
Figure 40 Price convergence between CWE bidding zones

94. The historical evolution of the monthly levels of price convergence between the bidding zones in the CWE FBMC is shown in Figure 40. Following the introduction of FBMC in May 2015, the time

series show a seasonal cycle (with higher convergence in summer than in winter). In the first years, between 2015 and 2018, convergence levels were relatively low: especially during some winter months, near to no price convergence was achieved. In 2019 and 2020, these convergence levels improved drastically. On average, price convergence was achieved during 41,9% and 43,2% of all hours, respectively. These numbers seem to increase even further based on the preliminary observations of 2021 day-ahead prices (data included until 31 August 2021).

Price spreads between CWE bidding zones

Histogram of differences between highest and lowest prices (among BE, NL, FR, DE and AT) between 2015 and 31 August 2021



Source: calculations CREG based on data EPEX SPOT

Figure 41 Price spreads between CWE bidding zones

95. When prices do not converge, the differences between the highest and lowest price (defined as price spread in Figure 41) are generally (in 33,7 % of all observed hours) between 1 and 15 € / MWh. Prices spreads fall, most often (12,5 %) in the category between 5 – 10 € / MWh. For higher price spreads, the relative occurrence drops: from 45 € / MWh onwards, less than 1% of all hours show such high price differences. On the extreme right side of the histogram, it may be observed that price spreads exceeding 100 € / MWh still occur in 0,4 % of all hours.

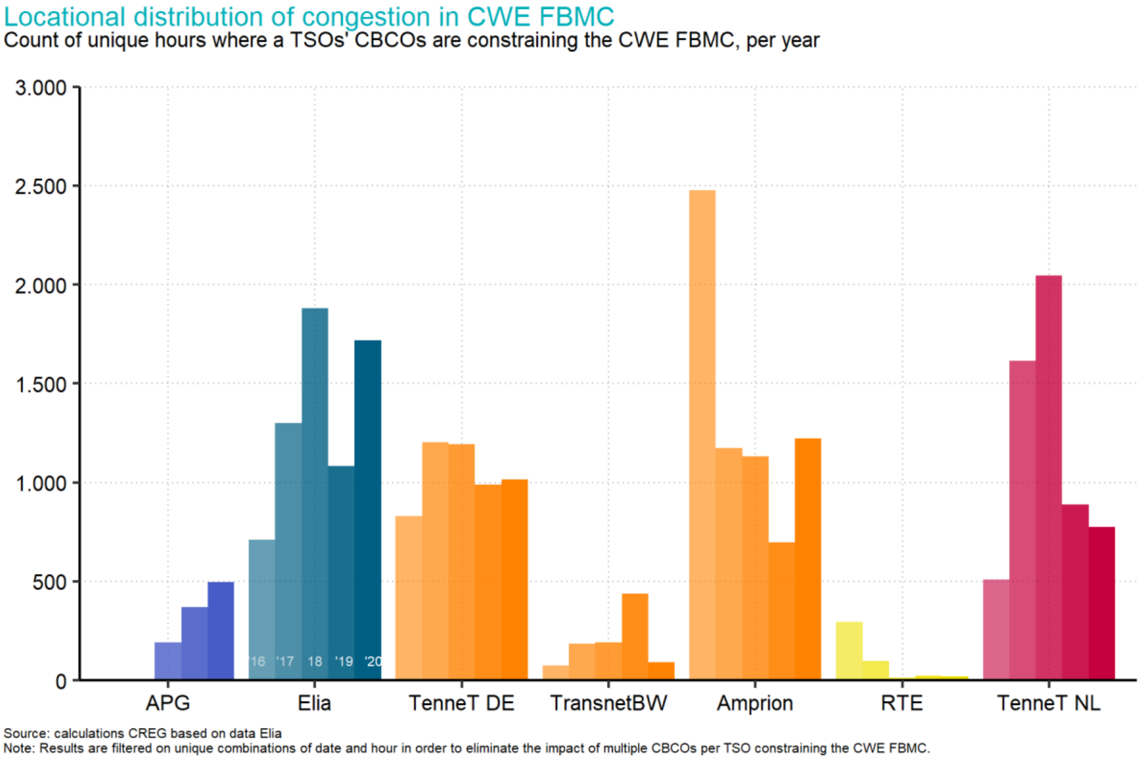


Figure 42 Locational distribution of congested network elements

96. In 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 clearing. Figure 42 shows the locational distribution of those network elements and their allocation to the responsible TSO. It is clear that, in 2020, there is a significant increase in number of hours where Elia reports constraining CBCOs in its network, compared to 2019. These numbers are also summarized in Table 5. At the same time the total number of hours with active CBCOs decreased in 2019 (3.143) after reaching its peak in 2018 (5.136). That number rose again in 2020, to 3.690 hours.[21]

	APG	Elia	TenneT DE	Transnet	Amprion	RTE	TenneT NL	TOTAL
2016		711	831	76	2.477	297	510	4.448
2017		1.299	1.203	185	1.173	97	1.615	4.719
2018	193	1.881	1.194	192	1.132	13	2.046	5.136
2019	369	1.084	990	437	698	24	890	3.143
2020	496	1.720	1.016	91	1.221	19	774	3.690

Table 5 Count of unique active constraints per TSO and per year

97. The remarkable increase of price convergence in the CWE FBMC is exemplary of the efforts that have been undertaken to improve the functioning of the capacity calculation and allocation methods. Notable improvements include the introduction of the 20% minRAM obligation by the CWE TSOs' (in April 2018) and the split of the German/Luxembourgish and Austrian bidding zone (in October 2018). The 20% minRAM has been replaced (or, more formally, complemented), in the meantime, with a 70% threshold corrected for temporary exemptions (such as action plans or derogations) since 1 January

[21] The "TOTAL" column in Table 5 does not add up to sum of the individual TSOs' columns, as it is possible that – during a given hour – multiple TSOs report active constraints. Similarly, it is possible that one TSO reports multiple active CBCOs during one single hour.

2020: this further improved the availability of cross-zonal capacity and the occurrence of price convergence. These items will be described further in section 5.4.

5.3. CONGESTION INCOME

98. 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 day-ahead) multiplied by the price spread.[22]

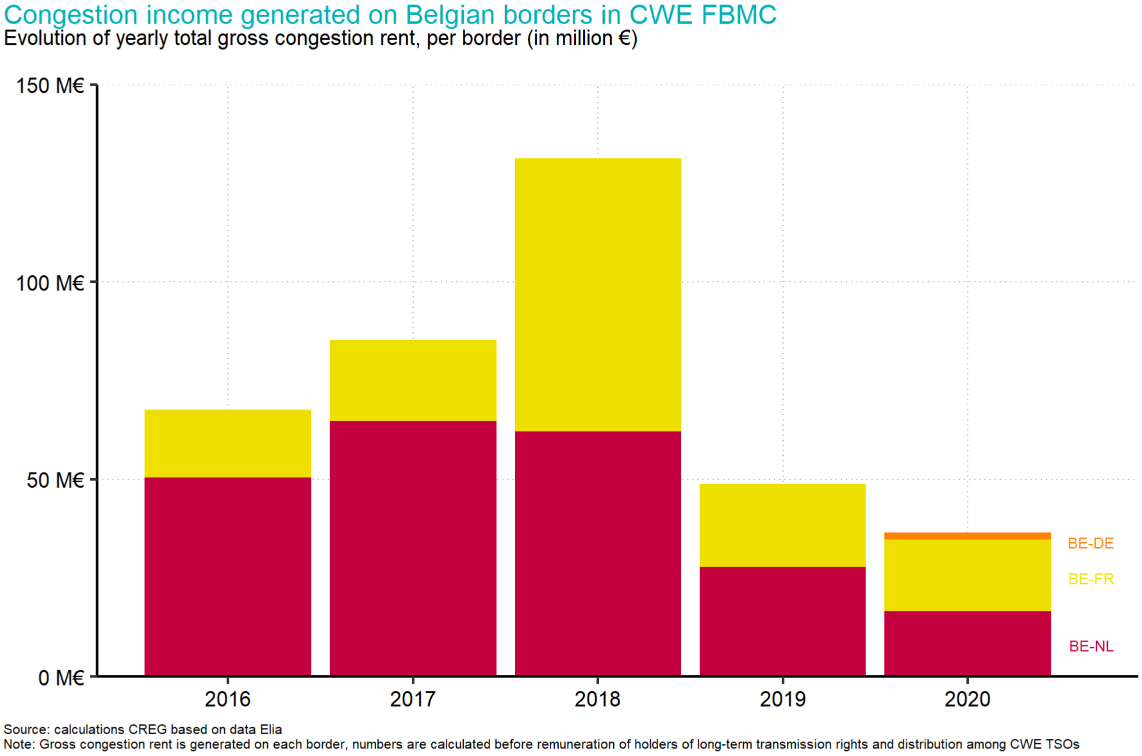


Figure 43 Congestion rent received by Elia in CWE FBMC

99. Figure 43 shows the evolution of the gross congestion income generated on Belgian borders in the day-ahead timeframe. The spikes in the yearly total received congestion income coincide with the years in Figure 40 where price convergence reached its lowest levels: towards the end of 2016, 2017 and 2018. Since 2019 and further in 2020, increased levels of price convergence had a negative impact on the congestion income received by TSOs.

In Belgium, congestion income generated on Belgian borders in the CWE FBMC amounted to 36,5 M€: a stark contrast against the all-time high 131,3 M€ in 2018 and a 25% reduction in one year from the 48,9 M€ in 2019.

100. The gross congestion income 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 the Belgian borders, i.e. before remuneration of long-

[22] 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.

term transmission right holders and the sharing of the so-called "*external pot*" between CWE TSOs. The net congestion income is calculated by substracting these two aspects from the gross income. The comparison between both is shown in Table 6: while the sharing of the external pot may have a positive or negative effect on the net congestion income for Elia, the remuneration of LT TR holders always has a negative impact: significant volumes of LT TRs need to be reimbursed at the market spread (for an overview of allocated LT TRs, see also section 4.2).

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

Table 6 Difference between gross and net congestion income for Elia

5.4. AVAILABLE CAPACITY

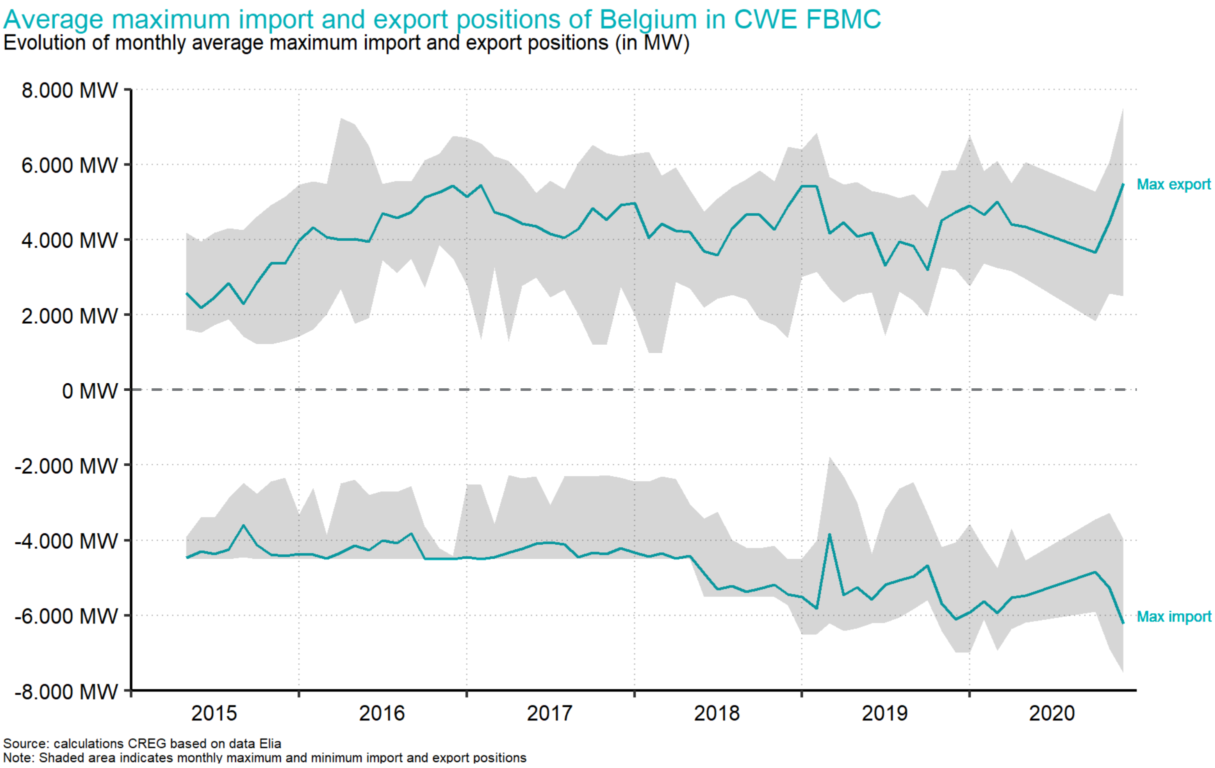


Figure 44 Average maximum import and export positions of Belgium in CWE FBMC

101. 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 44 shows the average monthly values as well as the monthly ranges (minimum and maximum). 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.

In 2020, the average maximum import and export positions have shown a decrease from March to October onwards, after which they increased strongly to all-time high values in both directions in December 2020 (5.498 MW export and 6.233 MW import). The highest hourly values recorded were also seen in December 2020, where 7.547 MW was available for import and 7.545 MW for export. Reasons for these historically high max import values include, among others:

- the split of the DE/LU and AT bidding zones, in October 2018;
- the introduction of the Clean Energy Package and the 70% threshold for interconnection capacities in January 2020;
- the entry into operation of the Nemo Link and ALEGrO interconnectors (in January 2019 and November 2020, respectively).

102. Elia, as well as other TSOs, has a legal obligation (embedded in several regulatory instruments) to maximize cross-zonal transmission capacities. In particular, the Clean Energy Package imposes that at least 70% of transmission capacity on network elements is offered for cross-zonal exchanges. The CREG monitors Elia's compliance with these provisions on a periodic basis. In 2020, Elia complied with the legal provisions related to the 70% threshold adjusted for the loop flow derogation in 81,3% of all hours and on 99,2% of all network elements. The actual 70% threshold, not accommodating for loop flows, was reached in only 1,5% of all hours or 91,7% of all network elements in 2020. The calculated results per type of network element (either cross-zonal, internal or PST) are summarized in Table 7. The impact of loop flows (which explain the different levels of compliance when looking at the 70% threshold or when looking at the minMACZT threshold[23]) is further explored in section 5.5.

	in % of network elements		**in % of hours**	
	70% compliance	minMACZT compliance	70% compliance	minMACZT compliance
Internal line	91,2%	98,8%	2,1%	77,2%
Cross-border line	94,0%	99,8%	0,5%	95,0%
PST	87,4%	99,7%	0,3%	97,0%
Total	**91,7%**	**99,2%**	**1,5%**	**81,3%**

Table 7 Compliance with 70% threshold and minMACZT per type of network element in 2020

[23] The legal obligation relates to the minMACZT threshold, i.e. the 70% criterium adjusted for excessive loop flows in application of the approved derogation. This derogation is however of a temporary nature: it is expected that the impact of (excessive) loop flows will decrease in the years to come.

5.5. LOOP FLOWS

103. Loop flows are observed on network elements within or between bidding zones, yet arise from exchanges within one other bidding zone and are therefore not within the immediate control of a TSO. Since 2017, Elia publishes the loop flows present in the day-ahead capacity calculation process.

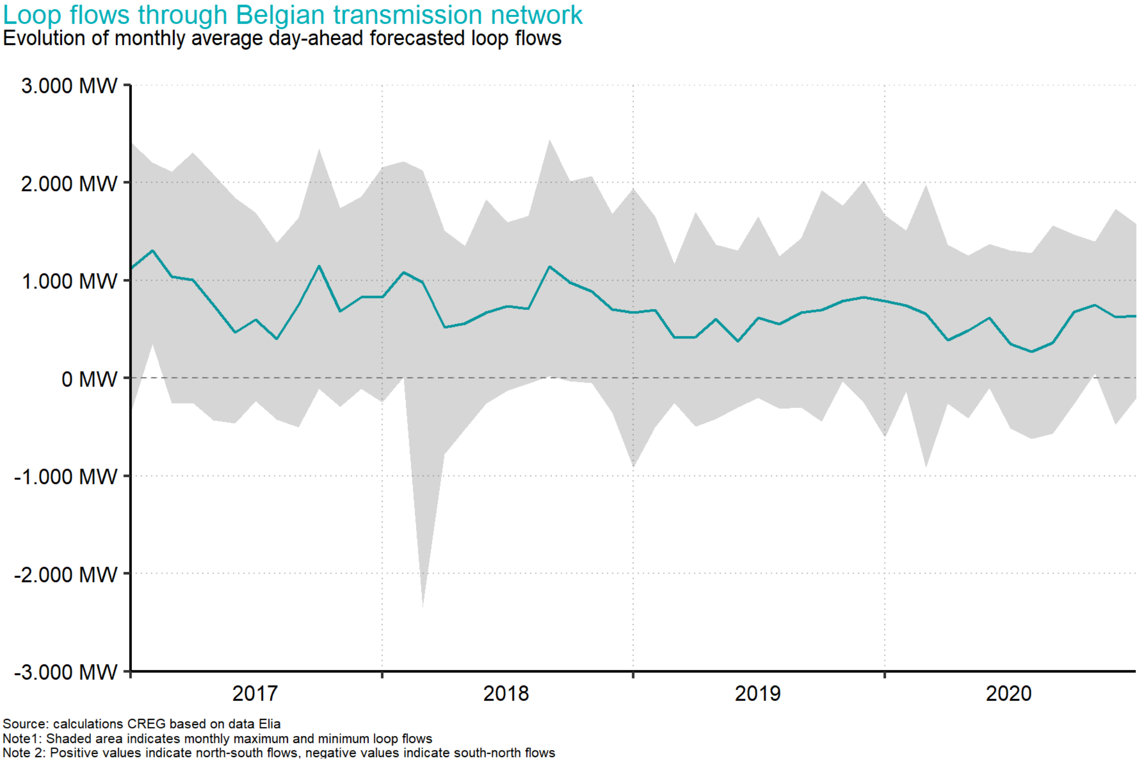


Figure 45 Loop flows through Belgian transmission network

104. In the Belgian transmission network, loop flows follow a structural north-to-south direction. They result mostly from exchanges within the German bidding zone, which is relatively much larger than the Belgian bidding zone (see also Figure 34). In 2020, average monthly loop flows ranged between 266 MW (in August) and 786 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 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 FBMC (or for the day-ahead cross-zonal exchanges).

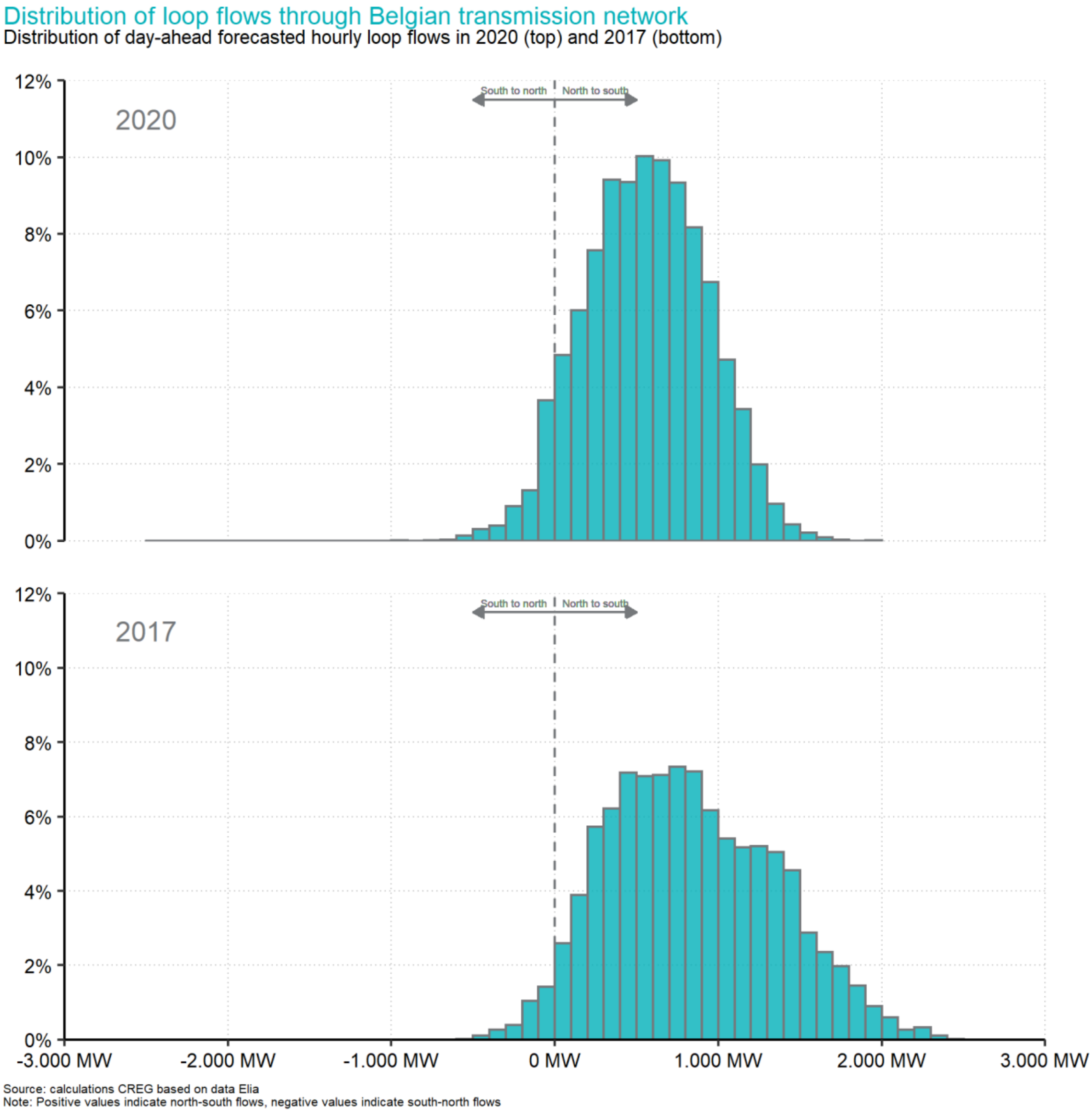


Figure 46 Distribution of loop flows through Belgian transmission network

105. The distribution of observed loop flows between 2017 and 2020 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 throughout the years with available data is shown in Table 8.

	2017	2018	2019	2020
North to south loop flows	96,8 %	97,0 %	95,1 %	93,2 %
South to north loop flows	3,2 %	3,0 %	4,9 %	6,8 %

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

106. Loop flows can also be measured on an individual network element level. In its monitoring of the compliance with the 70% threshold by the CREG, Elia reported a strong impact of these loop flows on individual CBCOs in its control area. Table 9 summarizes the average loop flows and internal flows in 2020, expressed as a percentage of F_{max} or the maximum allowed current on each network element.[24]

Critical Branch	Type	Average loop flows	Average internal flows
Achène - Gramme	internal	-7,9 %	-12,0 %
Avelgem - Horta	internal	-19,3 %	-17,9 %
Avelgem - Horta	internal	-14,6 %	-13,1 %
Champion - Courcelles	internal	-2,6 %	14,7 %
Champion - Gramme	internal	2,6 %	-16,7 %
Courcelles - Gramme	internal	-3,1 %	18,5 %
Doel - Mercator	internal	11,0 %	29,3 %
Doel - Mercator	internal	10,6 %	29,3 %
Doel - Mercator	internal	9,9 %	33,3 %
Doel - Mercator	internal	9,4 %	33,5 %
Doel - Zandvliet	internal	-19,9 %	17,1 %
Doel - Zandvliet	internal	-19,4 %	13,5 %
Gramme - Lixhe	internal	-1,3 %	12,9 %
Gramme - Van Eyck	internal	-0,3 %	7,2 %
Horta - Mercator	internal	-0,6 %	0,0 %
Lixhe - Van Eyck	internal	-1,5 %	1,6 %
PST Van Eyck 1	PST	6,6 %	
PST Van Eyck 2	PST	2,8 %	
PST Zandvliet 1	PST	16,0 %	
PST Zandvliet 2	PST	14,8 %	
Achène - Lonny	cross-border	16,6 %	
Aubange - Mont-Saint-Martin	cross-border	5,0 %	
Aubange - Moulaine	cross-border	2,7 %	
Avelgem - Mastaing	cross-border	4,9 %	
Borssele - Zandvliet	cross-border	-12,4 %	
Geertruidenberg - Zandvliet	cross-border	-13,6 %	
Maasbracht - Van Eyck	cross-border	-4,5 %	

Table 9 Average loop flows and internal flows per Critical Branch in 2020

[24] Positive values should be interpreted as a flow in the direction of the name of the network element. For example: on the first critical branch, the average loop flows reach 7,9% from Gramme to Achène (i.e. in the north-to-south direction).

6. INTRADAY MARKETS

107. Beyond the day-ahead timeframe and before the real time, market participants may trade electricity in local or coupled intraday markets. The Belgian continuous intraday market is coupled in the SIDC (the *Single Intraday Coupling*) to the markets in 22 other European countries.[25] 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.

108. After the gate closure of the cross-border intraday market, volumes can still be traded on the local intraday market in Belgium (either within EPEX SPOT or within Nord Pool) until 5 minutes before real-time.[26]

6.1. EXCHANGED VOLUMES

109. Traded volume in the Belgian intraday market operated by EPEX SPOT (coupled within XBID) decreased with 16% from 2019 to 2020 following an increase with 49% from 2018 to 2019. The traded intraday volume amounted to 16,3% of the traded volume on the day-ahead market in 2019 and 12,8% in 2020.

Market volumes (GWh)	2015	2016	2017	2018	2019	2020
Intraday	737	1.089	1.991	2.012	3.008	2.534
Day-ahead	23.700	19.600	17.900	25.900	18.407	19.753

Source: calculations CREG based on data EPEX SPOT

Table 10 Exchanged volumes in intraday vs. the day-ahead timeframe

110. A volume was traded on the intraday market during 95-97% of the hours in 2018-2020. The average volume traded during these hours was 352 MWh/h in 2019 and 304 MWh/h in 2020. In 2018 the increase in average traded volume (from 235 MWh/h in 2017 to 240 MWh/h) suggested that the intraday market participants more easily found a counterparty for their trades. The numbers in 2019 and 2020 show a confirmation of this trend.

[25] 23, including Italy, since its go-live in September 2021.

[26] The same remark as in footnote 15: only EPEX SPOT data was available for the below analyses, figures and tables. EPEX SPOT data relates to the functioning within XBID, not the local markets.

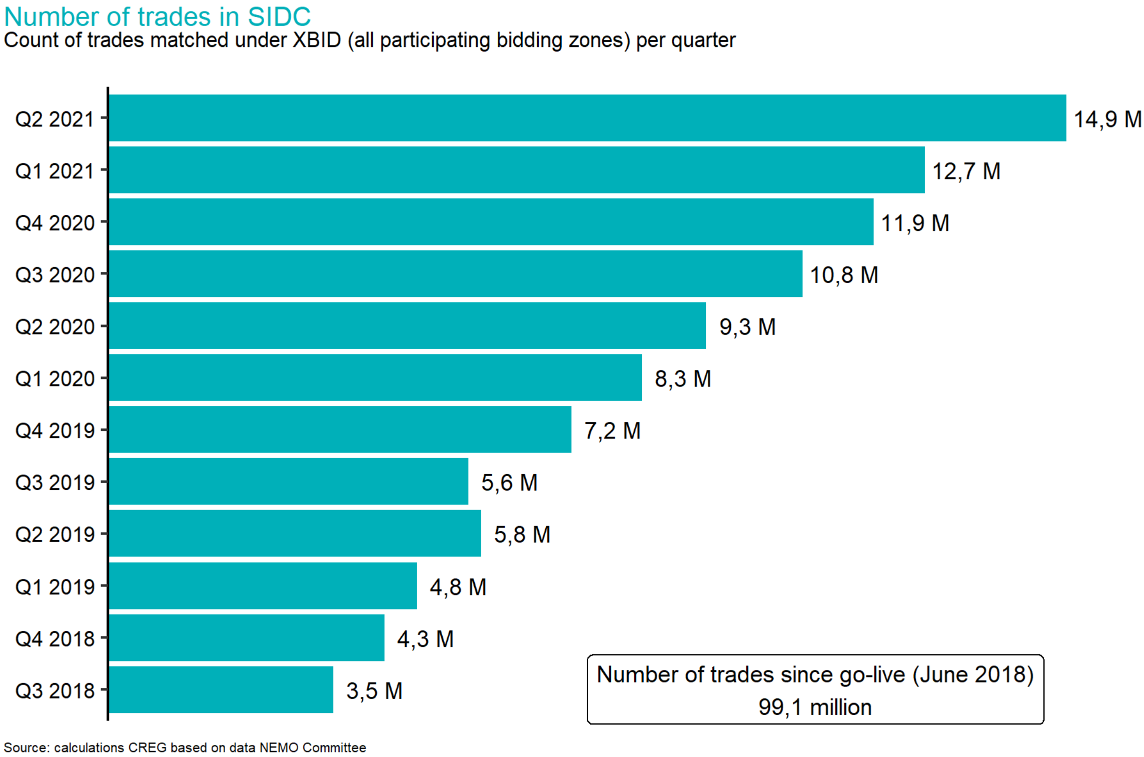


Figure 47 Number of trades in SIDC

111. 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 matched trades reached 13,8%, 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.

6.2. INTRADAY REFERENCE PRICES

112. The average prices[27] for 1 MWh in the day-ahead and intraday markets have decreased since 2018. Unsurprisingly considering the impact of the COVID-19 pandemic, the prices for 2020 are the lowest observed since 2015. More recently, however, the prices in the energy markets are again increasing and the average prices for 2021 are expected to be substantially higher.[28]

Reference prices (€ / MWh)	2015	2016	2017	2018	2019	2020
Intraday	43,96	37,93	45,73	56,29	40,19	31,18
Day-ahead	44,68	36,62	44,58	55,27	39,35	31,89

Source: calculations CREG based on data EPEX SPOT

Table 11 Reference price in intraday vs. the day-ahead timeframe

113. The annual average price differences between the intraday and day-ahead markets were below 1 €/MWh in both 2019 and 2020. In 2020, 95,3% of the differences between the hourly day-ahead and intraday prices were between -25 €/MWh and +25 €/MWh; in 2019, this was the case in 97,7% of the hours with an intraday transaction. In 2019 in 67,7% of the time the hourly spread between the day-ahead and intraday prices was lower than 5 €/MWh. Therefore, while the annual average price

[27] Intraday reference prices are calculated as a volume-weighted average of matched trades originating in the Belgi

[28] During the first 8 months of 2021, the average intraday reference price calculated by EPEX SPOT rose to 61,9 € / MWh.

differences between the day-ahead and intraday timeframes remain close to zero, the absolute values of the hourly price differences tend to increase.

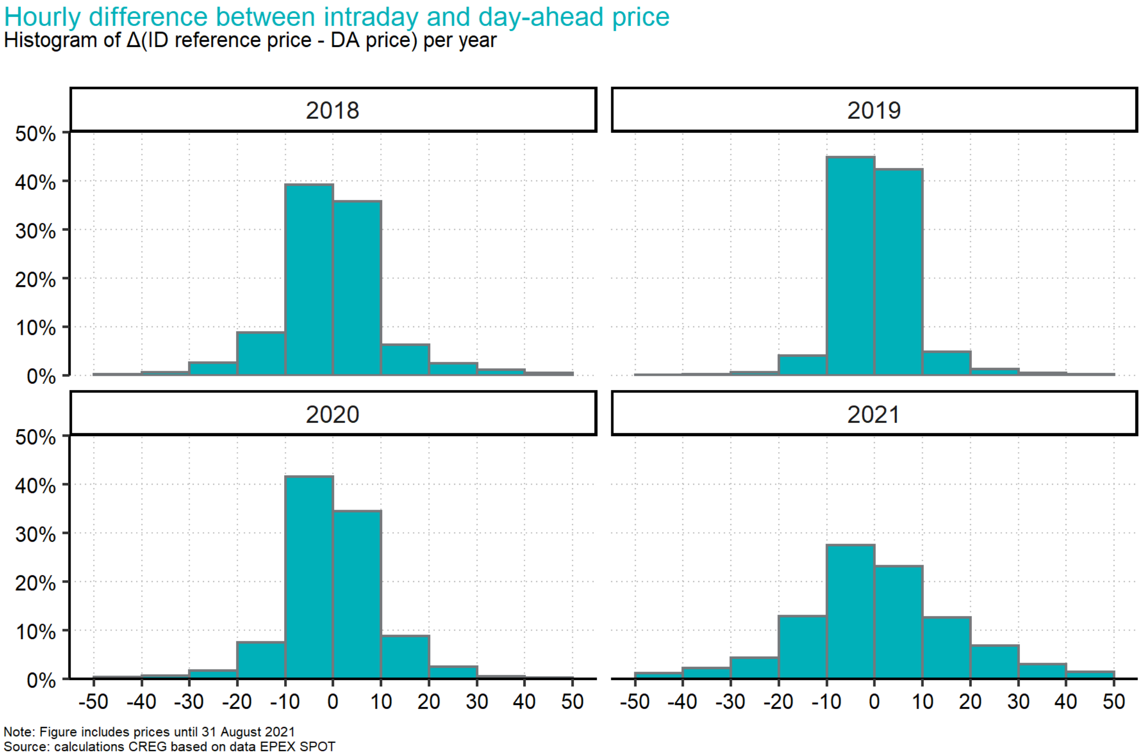


Figure 48 Hourly difference between intraday and day-ahead price

114. Minimum values for intraday prices have gone below -100 €/MWh since 2019 (lowest intraday price being -150 €/MWh in 2019 and -127,2 €/MWh in 2020). Negative prices for intraday trades increasingly occur as well. In 2019 reference prices were negative during 67 hours and in 2020 even during 305 hours (compared to occurrences between only 2 and 18 per year from 2015 to 2018). The occurrences in 2021 so far seem to be confirming the increasing trend.

Reference prices (€ / MWh)	2015	2016	2017	2018	2019	2020
Minimum	-9,33	-90,00	-44,12	-51,00	-150,00	-127,20
Maximum	420,00	572,94	426,58	590,00	276,51	612,20

Source: calculations CREG based on data EPEX SPOT

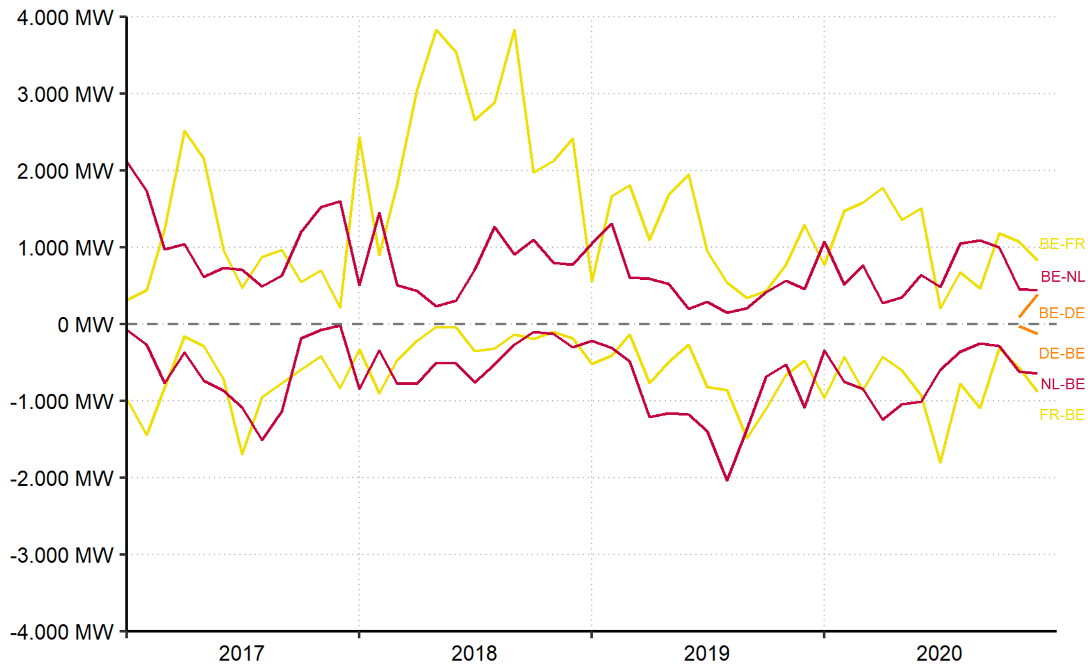
Table 12 Minimum and maximum reference prices in the intraday timeframe

115. The highest reference prices on the intraday market in recent years occurred in 2020. On December 7th in the afternoon prices went above 300 €/MWh, up to a maximum of 612 €/MWh.

6.3. AVAILABLE CAPACITY

116. In the intraday timeframe, Elia and the CWE TSOs make capacity available for cross-zonal trade. 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 bilateral trade possibilities (a so-called ATC extraction) from the day-ahead flow-based domain corrected for the day-ahead allocated capacities. The results of this extraction process, i.e. the bilateral ATCs on the coupled borders, are shown in Figure 49.

Average intraday import and export capacities
Evolution of monthly average import and export initial ATC (leftover from day-ahead) (in MW)



Source: calculations CREG based on data Elia

Figure 49 Average intraday import and export capacities

117. Relatively high 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 high 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]

118. 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 occurrence of such accepted requests (in % of observed hours per year) is shown in Table 13 below.

[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%	
2018	16,8%	18,0%		14,7%	13,0%		0%	0%		0%	0%	
2019	6,4%	8,5%		5,4%	11,8%		0%	0%		0%	0%	
2020	4,2%	8,9%	0%	12,3%	17,3%	0%	0%	0%	21,5%	0%	0%	12,4%

Source: calculations CREG based on data CWE TSOs

Table 13 Percentage of hours with accepted increase/decrease request

119. These summary statistics show that, since 2017, the number of increase requests on the northern and southern borders have decreased steadily, with (slight) improvements on the majority of borders (except BE-NL) in 2020.

120. An increase requests need to be validated by all other CWE TSOs and can in turn be fully accepted, partially accepted or rejected, depending on the impact of that request on the available margins of other TSOs' network elements. While the results in Table 13 refer to the accepted increase requests, the following summarizes the rate of acceptance or rejection per TSO.

Requesting TSO ↓	**Global acceptance rate** (i)	**Acceptance rate per TSO** (ii)						
		Elia	RTE	TenneT NL	Transnet BW	Amprion	APG	Tennet DE
Elia	15,1%	54,9%	63,2%	55,3%	85,1%	49,7%	92,5%	84,5%
RTE	51,0%	58,0%	64,5%	77,1%	72,4%	57,0%	76,2%	73,7%
TenneT NL	7,3%	59,7%	68,1%	42,0%	89,1%	49,6%	100,0%	81,4%
TransnetBW (iii)								
Amprion (iii)								
APG	60,3%	80,2%	84,1%	100,0%	95,2%	77,5%	92,3%	96,8%
TenneT DE (iii)								
GLOBAL	**31,5%**	**59,2%**	**65,6%**	**60,5%**	**79,8%**	**54,9%**	**85,4%**	**78,3%**

(i) The global acceptance rate shows how often an increase request is fully accepted, expressed as a fraction of all borders and hours

(ii) The acceptance rate per TSO shows how often a TSO (columns) accepts an increase request of another TSO (rows). It is possible that, on a given border during a given hour, multiple TSOs reject (partially) an increase request.

(iii) During the observed period, TransnetBW, Amprion and Tennet Germany did not issue any increase / decrease requests.

Source: calculations CREG based on data CWE TSOs

Table 14 Acceptance rate of increase requests per TSO between 1 October 2020 and 30 September 2021

121. On average, only 15,1% of all increase request issued by Elia are accepted. It is worth noting that in only 54,9% Elia accepts its own increase request, as this is part of the usual validation process: an increase is requested in nearly all hours (see also Table 15) and evaluated subsequently side-by-side with the other TSOs' requests. Elia's increase requests are most often rejected by Amprion (51,3%) and TenneT NL (44,7%).

	Elia	RTE	TenneT NL	TransnetBW	Amprion	APG	TenneT DE
Increase	99.7%	91.8%	97.3%	0.0%	0.0%	78.2%	0.0%
Decrease	0.0%	0.0%	0.0%	0.0%	12.2%	0.0%	0.0%

Source: calculations CREG based on data CWE TSOs

Table 15 Initially issued increase / decrease request per TSO between 1 October 2020 and 30 September 2021

122. Under specific situations, a TSO may freeze incoming increase requests, hence automatically rejecting all of them, irrespective of which TSO issued the original request. Between 1 October 2020 and 1 October 2021[30], no freeze functionality was triggered during 81,3% of the observed hours. RTE triggered this functionality in 16,7% of the hours, Amprion in 3,6% and TenneT NL in 0,04%. No other TSOs reported the activation of the freeze functionality.

123. The relatively low levels of accepted increase requests (Table 13 and Table 14), in particularly in 2020 (and 2021) may be partially explained by the relatively high utilization of the network in the day-ahead timeframe, leaving less capacity available for the intraday timeframe (see also sections 5.1 and 5.4).

[30] These data are reported by CWE TSOs since 30 September 2020, hence the limited time period under consideration.

7. BALANCING MARKETS

124. 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

125. 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. The total procurement cost of balancing capacity in 2020 amounted to 78 M€; this is 63% of the total cost in 2018 and 13% above the cost observed in 2017, but lower than in 2019.

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

Source: calculations CREG based on data Elia

Table 16 Procurement costs for each of the balancing reserve types procured in the LFC Area of Elia

7.1.1. FCR Capacity

126. 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.

127. However, evolutions in 2020 caused the FCR procurement costs to increase again. Since 30 June the procurement of FCR capacity occurs entirely through the regional procurement platform of Regelleistung.

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

(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 17 Capacity needs and procurement costs for FCR capacity procured in the LFC Area of Elia

7.1.2. aFRR Capacity

128. 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.

129. The total aFRR capacity costs have been decreasing since 2018. As the procured volume is fixed (slightly higher than before 2019), the decrease in total costs is due to a decreasing average procurement cost per MW/h (below 20 €/MW/h in 2019 and the first part of 2020). However, the impact of the design introduced in September 2020 is not yet apparent in the numbers. Since the procurement of aFRR capacity on short-term basis (one and two days before delivery), the average price for 1 hour of 1 MW of aFRR capacity is increasing again. The average price in the last three months of 2020 was at 34,5 €/MW/h (almost the same level as in 2018) and preliminary data for 2021 show that the average price is increasing further.

130. Since September 2020 the bid price for upward aFRR capacity may be different than the bid price for downward aFRR capacity. The analysed period is so far too short to draw conclusions.

aFRR capacity	2015	2016	2017	2018	2019	2020
Need (MW)	140	140	142	139	145	145
Average cost (€/MW/h)	23,5	27,3	28,0	35,5	19,9	16,7 (i) 34,5 (ii)
Upward aFRR (€/MW/h)						8,3 (i) 19,4 (ii)
Downward aFRR (€/MW/h)						8,3 (i) 15,1 (ii)

(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 18 Capacity needs and procurement costs for aFRR capacity procured in the LFC Area of Elia

7.1.3. mFRR Capacity

131. 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 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] was 490 MW from February to June 2020 and increased to 640 MW starting from July 1st.

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

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

(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**e**
Source: calculations CREG based on data Elia

Table 19 Capacity needs and procurement costs for mFRR capacity procured in the LFC Area of Elia

132. Since mFRR capacity is procured daily, the average price for 1 MW of mFRR capacity reserved for 1 hour in 2020 was 6,0 €. mFRR Standard costs on average 6,7 €, with the highest average cost of 10,17 €/MW/h for the contracting period between 16:00 and 20:00. mFRR Flex costs on average 4,25 €/MW/h with the highest average cost of 6,09 €/MW/h for the contracting period between 08:00 and 12:00. mFRR capacity is remunerated to the BSP at the offered bid price. As Table 20 shows, the maximum prices paid for 1 MW of mFRR capacity can be substantially higher than the average yearly values.

2020 (€/MW/h)	mFRR Standard Capacity		mFRR Flex Capacity	
	Average price	Maximum price	Average price	Maximum price
00:00-04:00	1,91	21,00	1,41	82,50
04:00-08:00	3,30	21,00	2,14	82,50
08:00-12:00	8,96	63,66	5,88	41,30
12:00-16:00	8,61	51,34	5,61	50,75
16:00-20:00	10,17	69,33	6,09	52,00
20:00-00:00	7,22	73,00	4,42	39,84
OVERALL	**6,70**		**4,25**	

Source: calculations CREG based on data Elia

Table 20 Average and maximum prices for mFRR Standard Capacity and mFRR Flex Capacity procured on a daily basis for the contracting periods from 4 February until 31 December 2020

7.2. BALANCING ENERGY

133. 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.

134. 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[32]. 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[33] 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.

[32] 5 minutes is the target value for the full activation time, and must be implemented before December 2024
[33] Typically mFRR is fu

135. The use of balancing resources to compensate system imbalances attained 1,12 TWh in 2020. Compared with an estimated Belgian consumption of 81,14 TWh in 2020, compensating the system imbalance accounts for 1,4% of the energy consumed. In 2020, 43,9% of the balancing needs are compensated by imbalance netting. This share has increased with respect to 2019 (37,6%) and 2018 (36,3%).

The use of imbalance netting and aFRR to compensate negative system imbalances has only slightly increased with respect to 2019 (+1,3%). However, this slight increase follows a large increase in 2019 (+6,8%). The increase is solely attributable to the use of imbalance netting as the use of aFRR has decreased over the same period. The use of imbalance netting and aFRR to compensate positive system imbalances has decreased year over year in 2020 (-5,2%) and in 2019 (-2,1%).

The use of upwards mFRR increased with 36,1% year over year in 2020. The use of mFRR is volatile: the year-over-year change was -14,0% in 2019 and +28,6% in 2018.

Reserve sharing was not used in 2020.

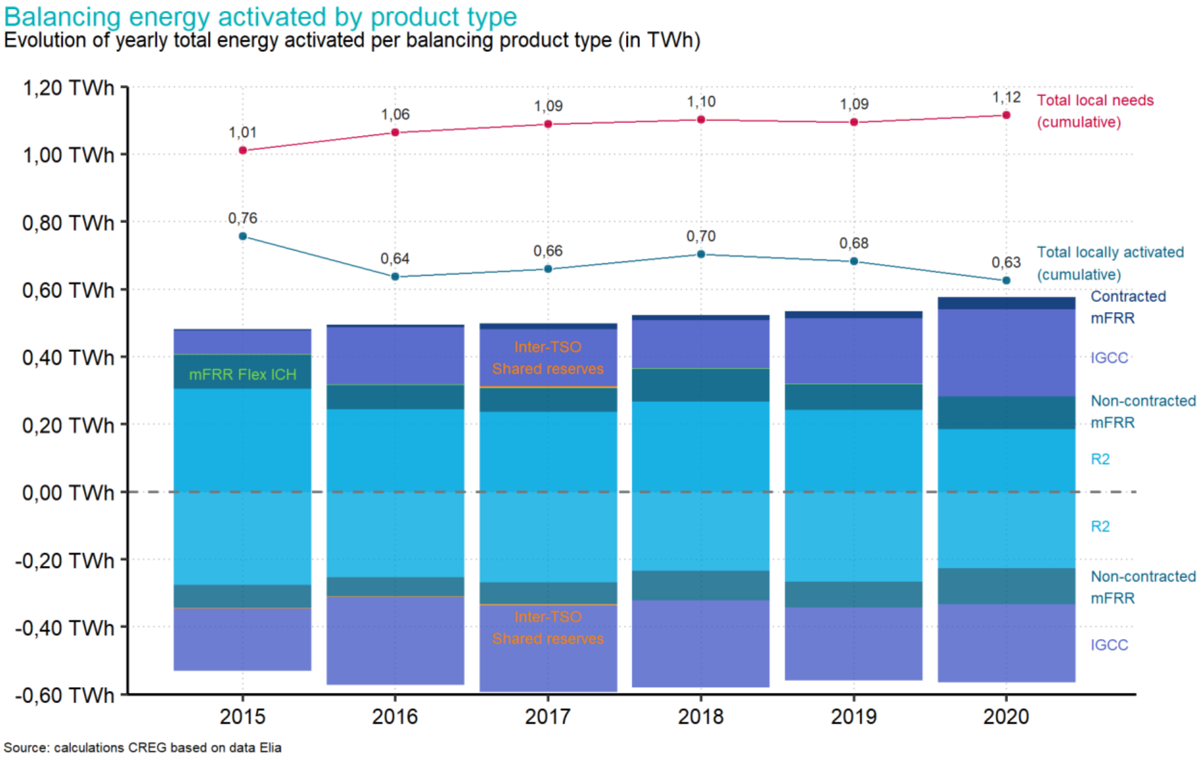


Figure 50 Balancing energy activated per product type

(GWh)	2015	2016	2017	2018	2019	2020
Contracted mFRR	4,1	7,4	15,6	15,2	20,6	35,6
IGCC -	-184,1	-259,7	-256,6	-258,3	-216,6	-232,4
IGCC +	70,5	168,3	170,6	142,5	195,0	257,4
Inter-TSO Shared Reserves (-)	-0,2	-0,5	-2,9	-0,5	-0,8	0,0
Inter-TSO Shared Reserves (+)	0,0	0,0	3,1	0,0	0,3	0,0
mFRR Flex	0,2	0,8	0,6	0,6	0,6	0,0
mFRR Flex ICH	1,1	0,3	0,8	0,0	0,0	0,0
Non-contracted mFRR (-)	-69,4	-56,9	-65,3	-86,6	-75,7	-106,9
Non-contracted mFRR (+)	101,6	73,3	71,3	97,6	76,4	97,2
R2 (-)	-275,8	-253,9	-268,2	-235,1	-266,6	-225,7
R2 (-)	304,3	243,8	236,1	267,1	242,4	185,7

Source: calculations CREG based on data Elia

Table 21 Balancing energy activated per product type

7.3. IMBALANCES

136. 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 22 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 Guideline) article 55

Table 22 Flow of payments of imbalance prices

137. 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.

138. 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.

139. 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.

140. 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).

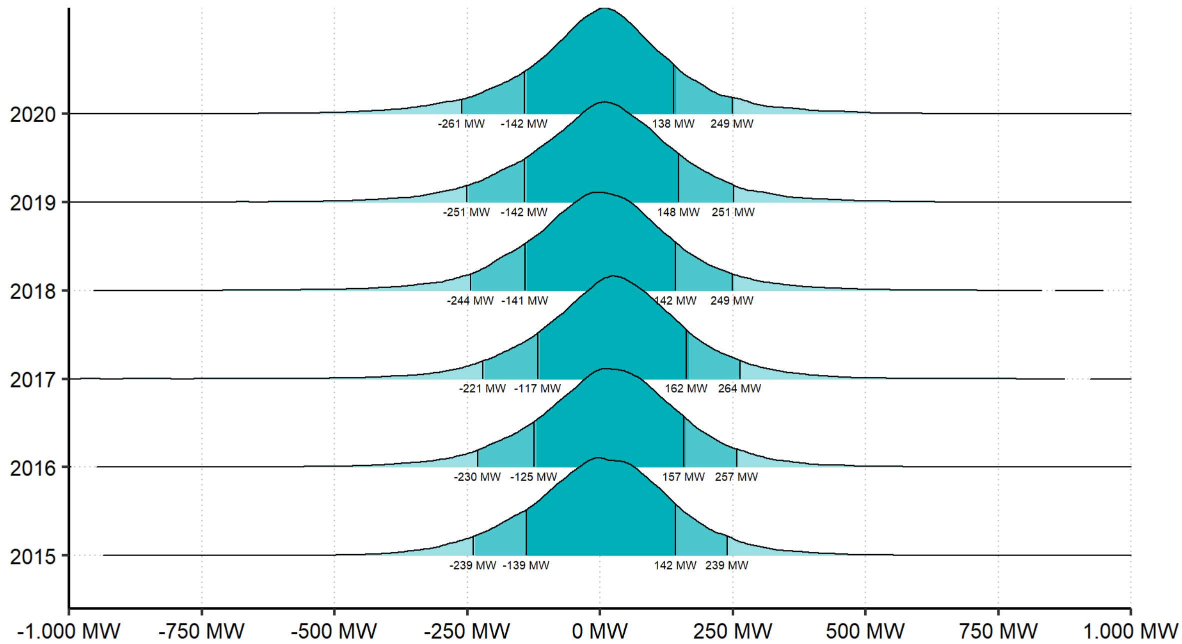
7.3.1. System imbalance

141. The distribution of the system imbalance follows a similar pattern each year, as shown in Figure 51. The number of quarter-hours with positive and quarter-hours with negative system imbalances is quasi the same within a year since 2018 (48-53 % of the time with negative imbalances versus 42-44% in 2016-2017).

142. On average during 71% of the quarter-hours per year, the system imbalance is between - 150MW and + 150MW (the range in which the alpha component in the imbalance price remains 0 €/MWh, according to the methodology implemented since 2020). The darker areas in Figure 48 show this range for each year with the specific thresholds for the 15th and 85th percentile (i.e., the middle 70% of the observations).

143. 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 23). Such large imbalances did occur more in 2019, with extremes of +1342 MW and -1602 MW. In 2020 the system imbalances ranged from -1059 MW to +1034 MW.

Evolution of observed system imbalances
Yearly distribution of quarterly system imbalances per year between 2015 and 2020 (in MW)



Source: calculations CREG based on data Elia
Note: vertical lines indicate 5%, 15%, 85% and 95% quartile

Figure 51 Evolution of observed system imbalances

Number of quarter - hours	OFF-CHART OBSERVATIONS									
	[-1700 - -1600]	[-1500 - -1400]	[-1400 - -1300]	[-1300 - -1200]	[-1200 - -1100]	[-1100 - -1000]	[1000 - 1100]	[1100 - 1200]	[1200 - 1300]	[1300 - 1400]
2015										
2016						1				
2017	1			2		3				
2018										
2019	1	1	1	1	2	2	1	4	1	1
2020						1	1			

Source: calculations CREG based on data Elia

Table 23 Evolution of observed system imbalances

144. In 4% of the time (about 1400 quarter-hours), 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.

145. Each year, system imbalance of more than 150 MW (in positive or negative direction) on average last two quarter-hours.

146. In 2020, on 83 occasions a large system imbalance of 150 MW (in positive or negative direction) lasted more than 2 hours, of which 6 times longer than 5 hours. The longest period in 2020 lasted 28 consecutive quarter-hours: an negative system imbalance ranging between - 173MW and -999 MW occurred on April 19th from 09:00 until 16:00.

7.3.2. Imbalance prices

147. On average the imbalance price was lower in 2020 (at 33,8 €/MWh) than in the years before. This trend can also be observed for quarter-hours for which the imbalance price is based on 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). Based on the observations of 2021 so far, however, the trend is reversing towards an average imbalance price so far of above 60 €/MWh and even above 100 €/MWh in case the imbalance price is based on the MIP.

148. 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 drops below zero in 2020, reversing the financial flow between the BRP and the TSO (as indicated previously in Table 22). Based on the observations so far this is also the case in 2021 (with an average imbalance price currently at below -10 €/MWh).

(€/ 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 (January – August)	62,2	120,8	-13,3

Source: calculations CREG based on data Elia

Table 24 Yearly average imbalance prices

149. 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 so far is even 3.200 €/MWh.

150. The imbalance price if based on the MDP has reached values lower than - 320 €/MWh in 2019 and 2020. In 2021 the minimum so far is observed at -496 €/MWh.

(€/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 (January – August)	3.199,9	-496,0

Source: calculations CREG based on data Elia

Table 25 Yearly maximum imbalance prices

151. 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 already in both 2020 and 2021, both in case of positive and negative imbalances.

152. In 2020, the average alpha value in case the imbalance price is based on the MDP, was 3,4 €/MWh (even 12,9 €/MWh when only taking into account the quarter-hours during which the alpha is larger than zero). Observations for 2021 so far indicate that the increasing trend continues (respectively 5,1 €/MWh and 17,7 €/MWh).

(€/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 (January – August)	5,1	17,7	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 26 Alpha component if imbalance price is based on MDP

153. In 2020, the average alpha value in case the imbalance price is based on the MIP, was 4,4 €/MWh (even 15,3 €/MWh when only taking into account the quarter-hours during which the alpha is larger than zero). Observations for 2021 so far indicate that the increasing trend continues (respectively 7,4 €/MWh and 20,0 €/MWh).

(€/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 (January – August)	7,4	20,0	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 27 Alpha component if imbalance price is based on MIP

154. The trend in imbalance prices experienced, in 2021, a remarkable shift compared to 2020. Firstly, imbalance prices started to increase in 2021 (as opposed to their relatively stable trend in 2019 and 2020). Secondly, the volatility of the imbalance prices rose significantly. The imbalance prices in times of a surplus in the system (i.e. when the system is long) remain similar to the same prices when the system experiences a deficit (i.e. when the system is short). This is illustrated in Figure 52.

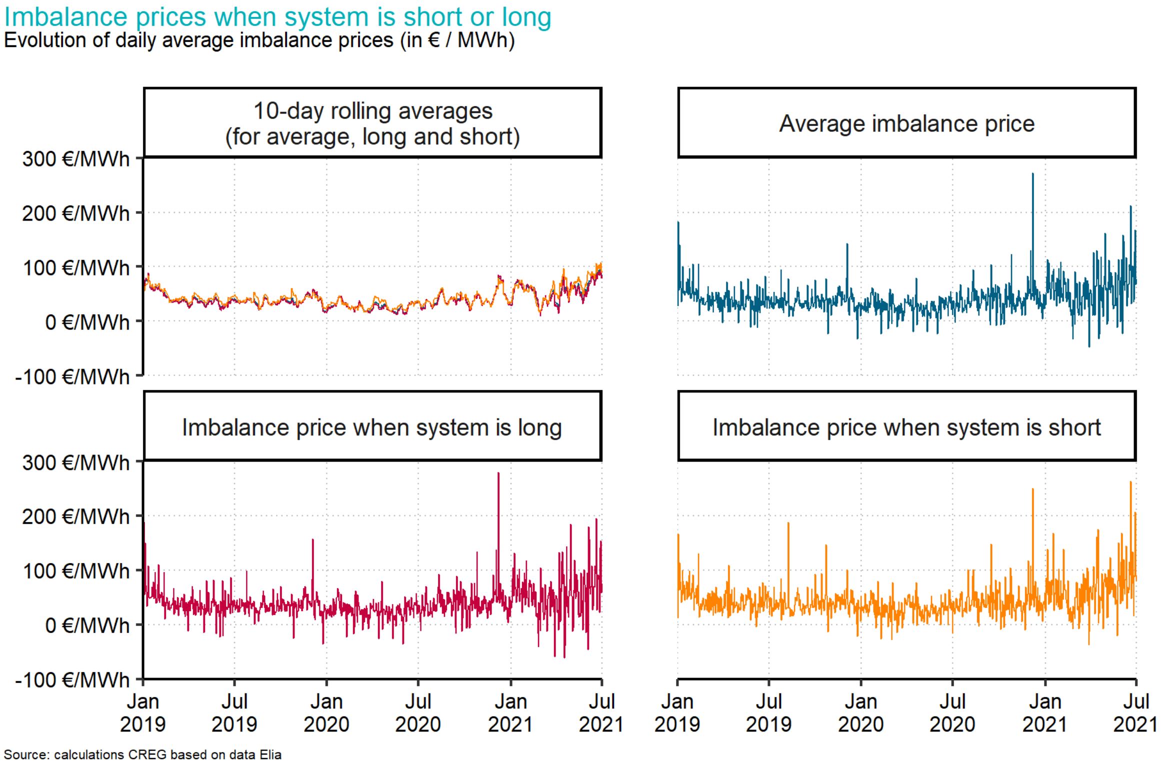


Figure 52 Imbalance prices when system is short or long

155. Figure 53 depicts the evolution of the system imbalance and the alpha component per quarter-hour from 2015 until the end of August 2021. The impact of the new design of the alpha component as of the 1st of January 2020 is clearly visible. However, 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.

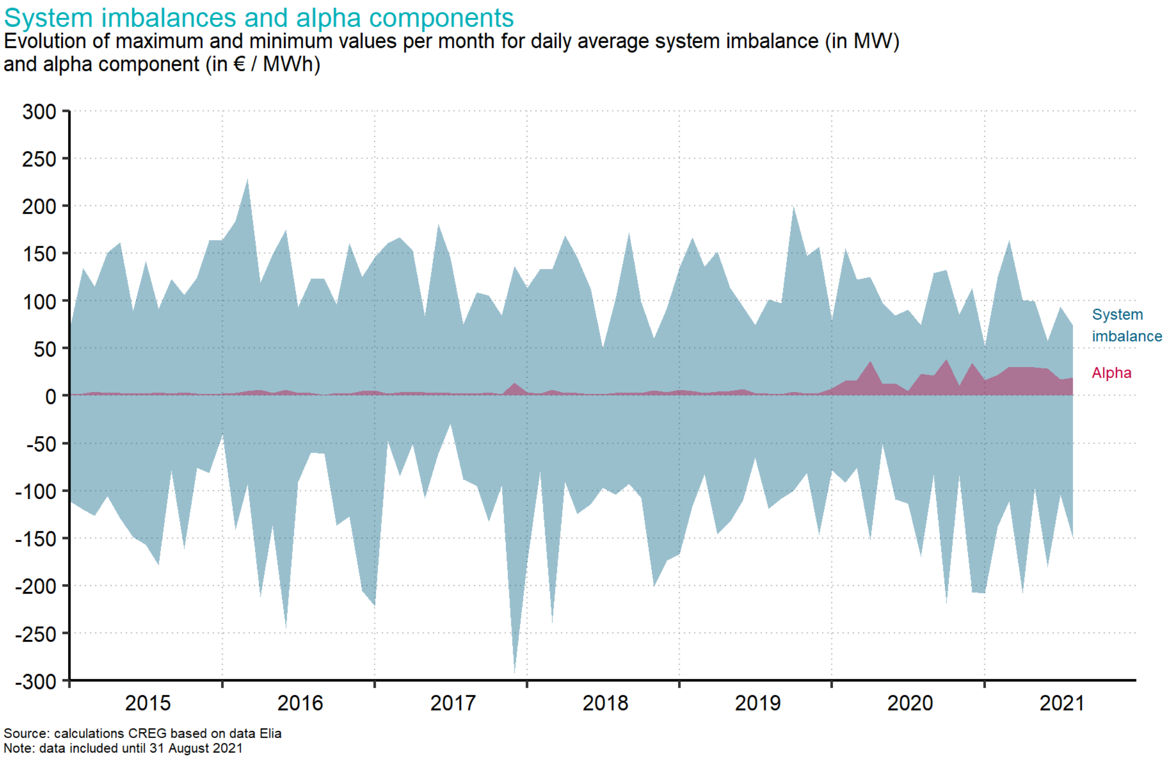


Figure 53 System imbalances and alpha components

8. NON-BALANCING ANCILLARY SERVICES

156. 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).

157. 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 prohibited except in exceptional cases (for instance some investments for first-time participation to the service or tariffs costs). Hence, the reservation cost for voltage services remained low just below 0.5 M€ in 2019 and 0.25 M€ in 2020.

158. 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 2020 the activation costs are nonetheless still high at 13.1 M€ in 2020 (5% lower than in 2019 but 19% higher than in 2018.)

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

Source: calculations CREG based on data Elia

Table 28 Reactive power costs

159. 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 increased slightly to 7.32 M€ in 2019 but dropped to 7 M€ in 2020, its lowest level since 2015.

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

Source: calculations CREG based on data Elia

Table 29 Black start costs

160. 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. CONCLUSION

In this study, the CREG analyses the state and functioning of the Belgian wholesale electricity markets. Historical evolutions are presented, with a focus on the years 2019 and 2020, extending to 2021 where sufficiently reliable data is already available.

The CREG presents the evolution of the Belgian total load and electricity consumption in chapter 1. Chapter 2 focuses on the installed capacity, availability, generation and carbon intensity of electricity production units. In chapter 3, the physical import and export of electricity from and to neighbouring countries is presented.

In the subsequent chapters and linking to the findings in the first chapters, the sequence of electricity markets is 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 is presented in chapter 8.

While the current study already presents data covering a significant part of the year 2021, these analyses will be repeated and the scope extended in a next edition of the Monitoring Report, to be published in the second quarter of 2022.

The Board of Directors of the CREG approved this study at its meeting of 21 October 2021.

For the Commission of Electricity and Gas Regulation:

Andreas TIREZ	Koen LOCQHET
Director	Acting president of the Board of Directors

LIST OF FIGURES

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LIST OF ABBREVIATIONS

aFRR	Automatic Frequency Restoration Reserves
ATC	Available Transfer Capacity
BRP	Balance Responsible Party
CBCO	Critical Branch / Critical Outage
CCGT	Combined Cycle Gas Turbine
cNTC	Coordinated Net Transfer Capacity
COVID-19	Coronavirus Disease 2019
CWE	Central-West Europe
D-1	Day-Ahead
EEA	European Environment Agency
Euphemia	Pan-European Hybrid Electricity Market Integration Algorithm
FBMC	Flow-Based Market Coupling
FCR	Frequency Containment Reserves
FTR (options)	Financial Transmission Right (-options)
$gCO_{2\ eq}$	Grams of carbon dioxide equivalent
HHI	Herfindahl – Hirschman Index
HVDC	High-Voltage Direct Current
IGCC	International Grid Control Cooperation
JAO	Joint Allocation Office
LFC (Block)	Load-Frequency Control (Block)
LT TR	Long-Term Transmission Right
M-1	Month-Ahead
MACZT	Margin Available for Cross-Zonal Trade
MDP	Marginal Downward Price
mFRR	Manual Frequency Restoration Reserves
MIP	Marginal Incremental Price
MNA	Multi-Nemo Arrangements
NEMO	Nominated Electricity Market Operator
OTC	Over-the-counter
PTR(-UIOSI)	Physical Transmission Right (-Use-It-Or-Sell-It)
(solar) PV	(solar) Photovoltaic
Q-1	Quarter-Ahead
R2	Secondary Reserves
RAM	Remaining Available Margin
RES	Renewable Energy Sources
SDAC	Single Day-Ahead Coupling
SIDC	Single Intraday Coupling
TSO	Transmission System Operator
TTF	Title Transfer Facility
XBID	Cross-border Intraday
Y-1	Year-Ahead

REFERENCES

Works referred to in this study include:

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- Study (F) 1734 on the functioning and price evolution of the Belgian wholesale electricity market - monitoring report 2017
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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

The design of Figure 11 was largely based on and influenced by the work of Dr. C. Scherer

- SCHERER, C. (2019). *The evolution of a ggplot (Ep. 1).* https://www.cedricscherer.com/2019/05/17/the-evolution-of-a-ggplot-ep.-1/