CREG

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de l'Électricité et du Gaz

Study

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Study on the functioning and price evolution of the Belgian wholesale electricity market – monitoring report 2018

drawn up pursuant to article 23, § 2, second paragraph, 2° and 19°, of the law of 29 April 1999 on the organisation of the electricity market.

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INTRODUCTION

In this study, the COMMISSION FOR ELECTRICITY AND GAS REGULATION (CREG) examines the functioning and price evolution of the Belgian wholesale electricity market over the period 1 January to 31 December 2018. The CREG has carried out a similar study every year since 2007.

The aim of these studies is to inform all stakeholders about important aspects of the Belgian electricity market, in particular electricity consumption, generation, electricity trading on electricity exchanges, interconnections with foreign countries, and balancing.

To the extent possible, the historical background of the last 11 years (2007-2017) is provided. 2007 is included in this study since it pre-dates the economic and financial crises of the period studied. As such, the reader will be able to understand the evolution of the wholesale electricity market more easily.

This study includes 6 chapters :

1. the 1st chapter examines electricity consumption;
2. the 2nd chapter specifically focuses on electricity generation;
3. the 3rd chapter covers electricity trading on markets;
4. the 4th chapter analyses the interconnections between Belgium and its neighbouring countries;
5. the 5th chapter covers balancing;
6. the 6th and final chapter covers security of supply with an assessment of the capacity margin at the end of 2018 when nuclear availability was historically low.

Several conclusions will also be made at the end of the study. At the end of the document, the reader will find a glossary, the main abbreviations used in the study, a list of the works quoted, and a list of the figures and tables used throughout the study.

The Executive Committee of the CREG approved the present study at its meeting of 5 September 2019.

1. ELECTRICITY GRID LOAD

1.1. HISTORICAL BACKGROUND : SIGNIFICANT EVENTS

2008

- eruption of the financial crisis

2012

- February 2012 cold spell in France and Belgium

1.2. STATISTICS

1.2.1. Evolution of the Grid Load

At the European level

1. Figure 1 illustrates the total electricity demand as published by Entso-E from 2011 to 2018 for Belgium and its neighbouring countries France, the Netherlands, Germany and the United Kingdom. Total electricity demand for this region amounted to 1492 TWh in 2018; this is more or less constant in the observed period, with 1459 TWh the lowest and 1495 TWh the highest total demand. Belgium represents 6% of this total demand. If the UK is excluded, the Belgian share rises to 7.5%.

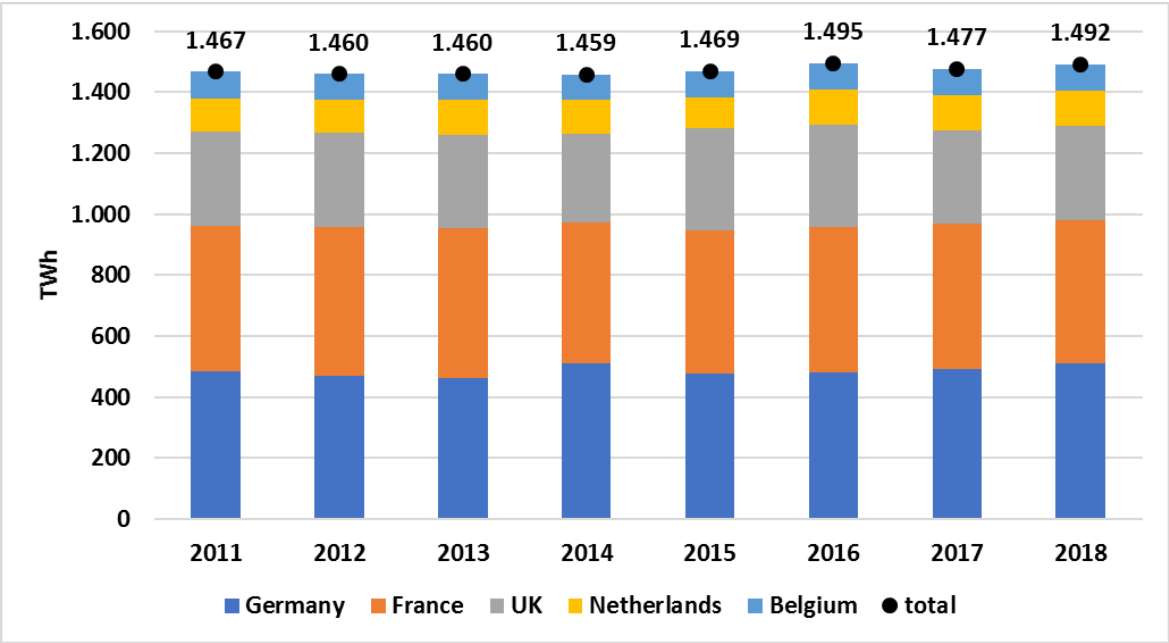


Figure 1: Evolution of the total electricity demand as published by ENTSO-E (TWh) from 2011 to 2017 for Belgium and its neighbouring countries
Sources: CREG, ENTSO-E[1]

[1] Some definitions and parameters of grid load between countries may differ slightly but the general trend per country is valid.

At the Belgian level

2. This section analyses the evolution of the Elia grid load[2], based on data provided by the TSO. Since this grid load does not take into account a significant part of the distributed generation, it is not equal to the total Belgian electricity consumption. However, this selected approach gives a good idea of how the wholesale electricity market is evolving.

3. The Elia grid load[3] amounted to 76.7 TWh in 2018, at a level slightly lower than the previous 4 years. Figure 2 shows the total Elia grid load over the last 12 years. Compared to 2007, the Elia grid load decreased by 12 TWh, or about -13%. The figure also shows the baseload part of the Elia grid load. This decreased from 56 TWh to 47 TWh, a decrease of about -16%. As such, the baseload part of the total grid load was more or less constant over the last 11 years, varying around 64%. This is remarkable, because one would expect that intermittent renewables would not only decrease the grid load, but also the baseload part of this load. The most obvious explanation for the constant baseload share is the increase of demand response to lower the peak.

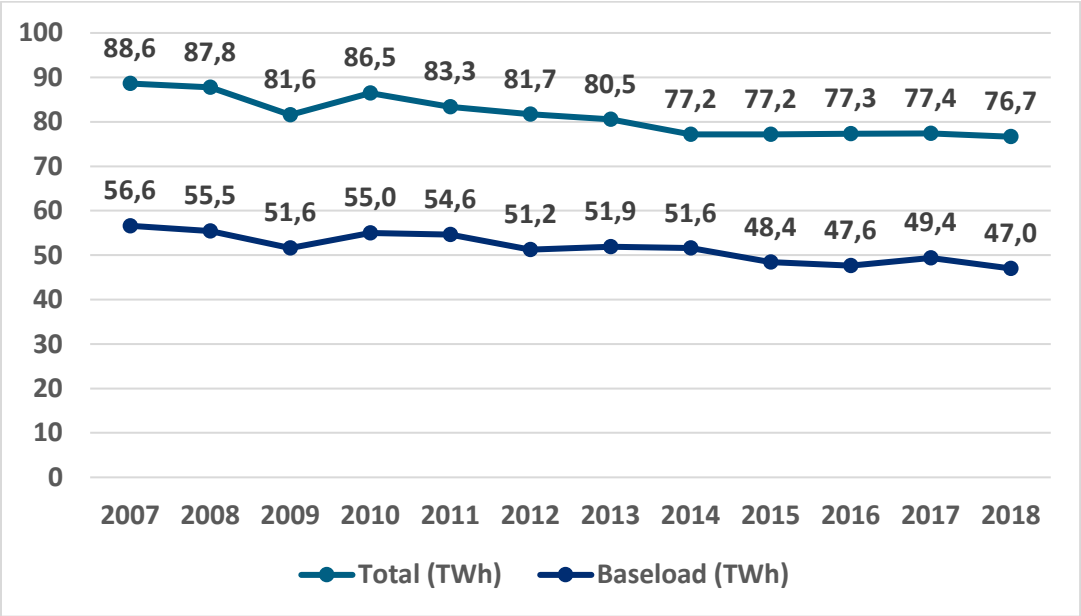


Figure 2: Total Elia Grid load and Baseload Elia Grid load during 2007 to 2018
Sources: Elia, CREG

[2] The Elia-grid load is a calculation based on injections of electrical energy into the Elia grid. It incorporates the measured net generation of the (local) power stations that inject power into the grid at a voltage of at least 30 kV and the balance of imports and exports. Generation facilities that are connected at a voltage of less than 30 kV in the distribution networks are only included if a net injection into the Elia grid is being measured. The energy needed to pump water into the storage tanks of the pump-storage power stations connected to the Elia grid is deducted from the total.
Decentralised generation that injects power at a voltage less than 30 kV into the distribution networks is not entirely included in the Elia grid load. The significance of this last segment has steadily increased in recent years. As such, Elia decided to complete its publication with a forecast of the total Belgian electrical load.
The Elia grid comprises networks of at least 30 kV in Belgium plus the Sotel/Twinerg grid in the south of Luxembourg. (Source: http://www.elia.be/en/grid-data/Load-and-Load-Forecasts/Elia-grid-load).

[3] The variations observed between the estimates of consumption of electricity of Synergrid and Elia are primarily due to the fact that (most of) the generation connected to the distribution grids and the losses of networks of the DSOs are not taken into account in the statement of electricity forwarding only by the Elia network.

4. The table below gives the detailed data on the total Elia grid load and its baseload part in 2007-2018. It also shows the average, maximum and minimum load per year for this period. The average Elia grid load in 2018 was 8,750 MW. The baseload Elia grid load was 5,365 MW, while the maximum amounted to 12,440 MW in 2018. This maximum Elia grid load was significantly lower than all the previous years.

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Total (TWh)	88,6	87,8	81,6	86,5	83,3	81,7	80,5	77,2	77,2	77,3	77,4	76,7
Max (MW)	14.033	13.431	13.513	13.845	13.201	13.369	13.385	12.736	12.634	12.734	12.867	12.440
Average (MW)	10.116	9.991	9.312	9.875	9.515	9.303	9.193	8.808	8.811	8.799	8.837	8.750
Min (MW)	6.462	6.330	5.895	6.278	6.232	5.845	5.922	5.889	5.529	5.438	5.638	5.365
Baseload (TWh)	56,6	55,5	51,6	55,0	54,6	51,2	51,9	51,6	48,4	47,6	49,4	47,0
%baseload	64%	63%	63%	64%	66%	63%	64%	67%	63%	62%	64%	61%

Table 1: Elia grid load (TWh) and power demand (MW) between 2007 and 2018
Sources: Elia, CREG

5. Figure 3 shows in more detail the evolution of the electricity peak demand in the Elia control area over the last 12 years. Four levels are shown here:

- the highest level (blue line - “maxCap”);
- 100 hours after the highest level (orange line - “Cap Hour 100”);
- 200 hours after the highest level (red line - “Cap Hour 200”);
- 400 hours after the highest level (dark blue line - “Cap Hour 400”).

Until 2014, all the trends observed were negative over the years. Since 2014, this bearish tendency has marked a stage of consolidation, but in 2018 the decrease of the maximal Elia grid load resumed.

The annual difference between the highest level of electricity demand (“maxCap”) and that of hour 100 level (“Cap Hour 100”) fluctuates between 900 and 1,300 MW. In other words, this means that additional power of only + 1,100 MW is necessary for less than 100 hours to meet the peak Elia grid load. For the following 100 hours (“Cap Hour 200”), slightly more than 200 MW was added. For the 400 hours (“Cap Hour 400”), or 4.6% of the time, it was necessary to rely on average on 1,600 MW, or 12.0% of the peak demand.

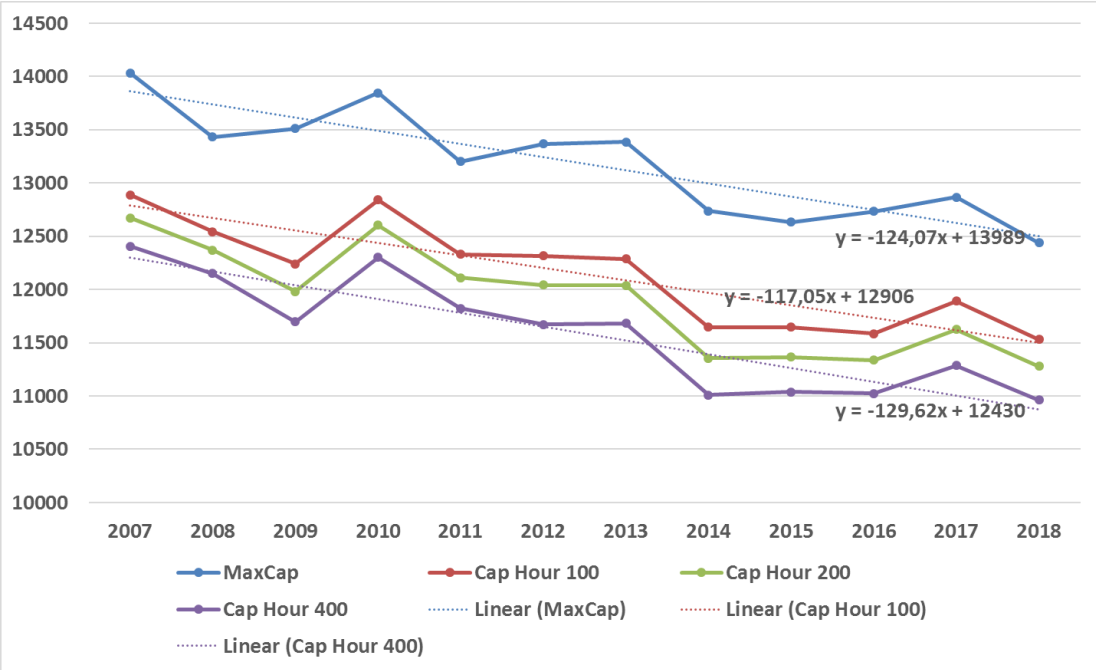


Figure 3: Evolution of the demand levels classified within the Elia control area (MW) for 2007-2018 (for the higher ¼ hour, hour 100, hour 200 and hour 400), like their trend curve - Sources: Elia and CREG

1.2.2. Electricity Demand according to Meteorological Conditions

6. Figure 4 shows the average Elia grid load per month for 2017 and 2018 compared to 2007 and 2008. The shape of the curves shows the seasonal effects on the Elia grid load. During the winter months, the average Elia grid load is appreciably higher (up to 2,000 MW higher) than in the summer months.

7. In January and November-October 2018, the monthly average Elia grid load was markedly higher than the year before.

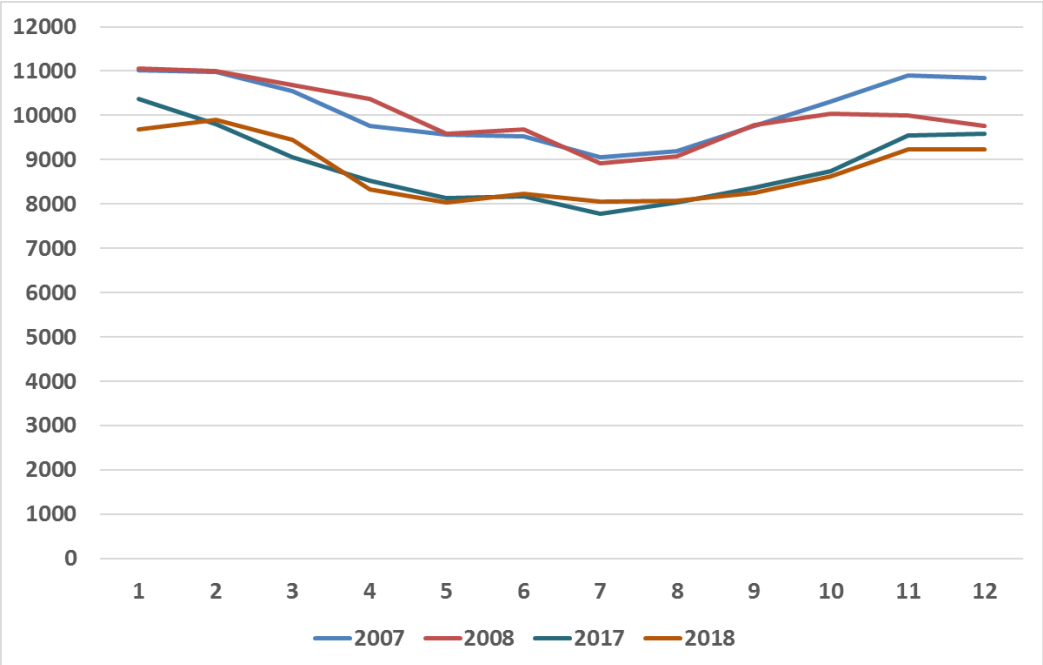


Figure 4: Average monthly Elia grid load for 2007-2008 and 2017-2018 (in MWh/hour) - Sources: Elia and CREG

1.2.3. Load Patterns and the Impact of Solar Panels

8. Figure 5 shows the evolution of the daily pattern of the average Elia grid load for the years 2007-2008 and 2017-2018. The peak just before midday in 2007 and 2008 has disappeared due to generation from solar panels. During the night and morning, the average Elia grid load in 2018 did not change compared to 2017. During the day, the average Elia grid load in 2018 was lower than in 2017.

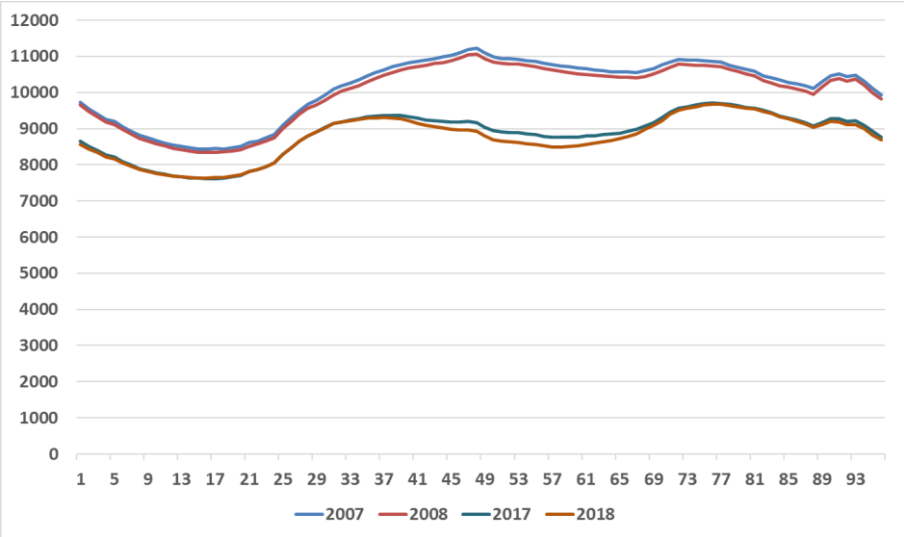


Figure 5: Average Elia grid load per quarter of an hour for 2007-2008 and 2017-2018 (MW) - Sources: Elia and CREG

9. These observations are confirmed by Figure 6 which shows the variability of the average Elia grid load during the day measured using standard deviation ("AV D-Stdev" - blue line) as well as the standard deviation of the difference in Elia grid load between two consecutive days ("StdDev of D-D-1" - red line). Figure 6 also illustrates on the right-hand axis the standard deviation of the difference between two consecutive quarters of an hour ("Stdev of QtoQ - right axis" - green line).

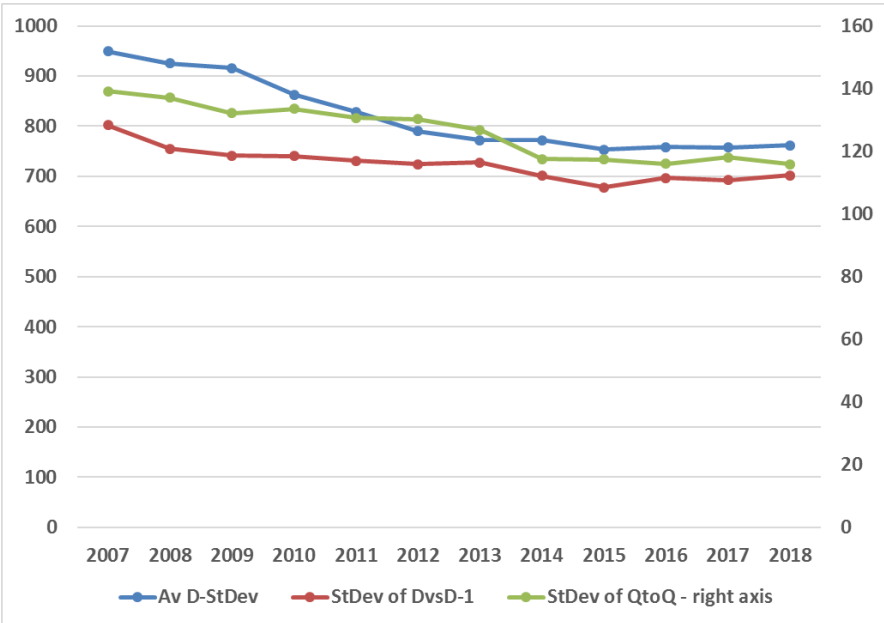


Figure 6: Annual variability of the average electricity demand during one day ("AV D-Stdev" - blue line), the difference between two consecutive days ("StdDev of D-D-1" - red line) and, on the right-hand axis, the difference between two consecutive fifteen minute intervals ("Stdev of QtoQ" - green line) (MW). - Sources: Elia, CREG

10. The constant lower levels of variability in 2018 and the years before compared to 2013 and earlier is an indication that the need for flexibility to meet the demand has decreased. This is confirmed in chapter six on *balancing.* Since 2013, a decrease in the resources required to maintain the power balance has been observed.

Impact of solar generation

11. The CREG only has TSO data on solar electricity generation for complete years from 2013 onwards. Figure 7 shows the daily pattern of the hourly average solar generation for Belgium for the period from 2013 to 2018. There is a clear increase in 2018 compared to the previous years. The solar generation at 1.00pm is 1,300 MW on average.

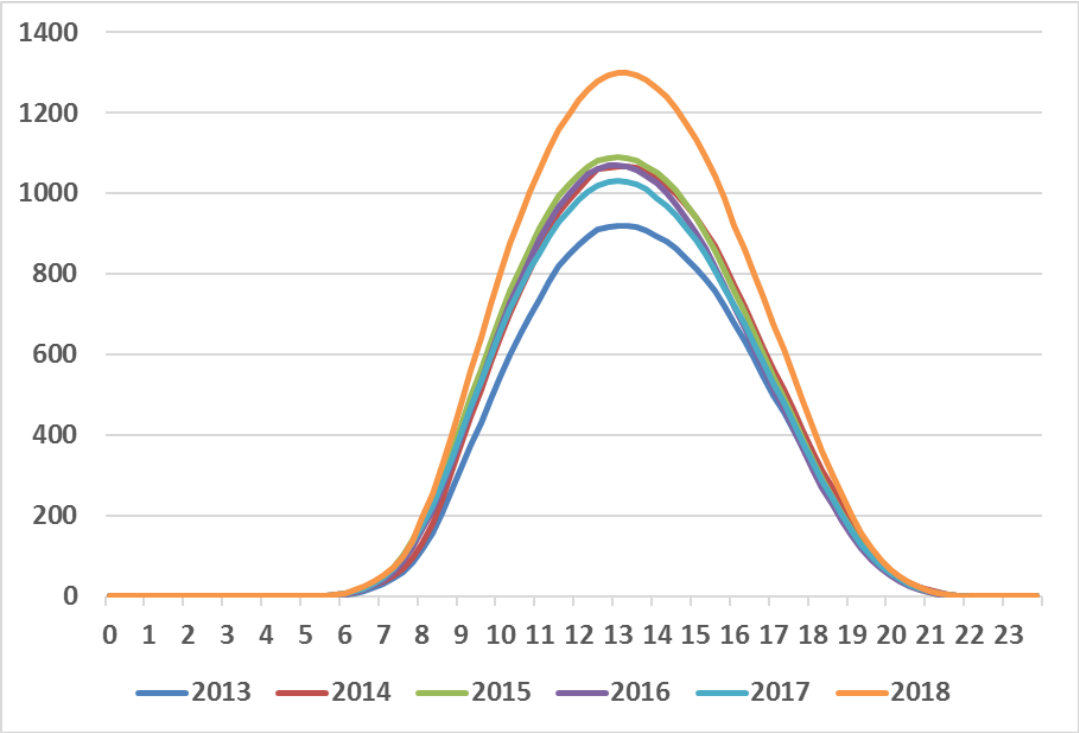
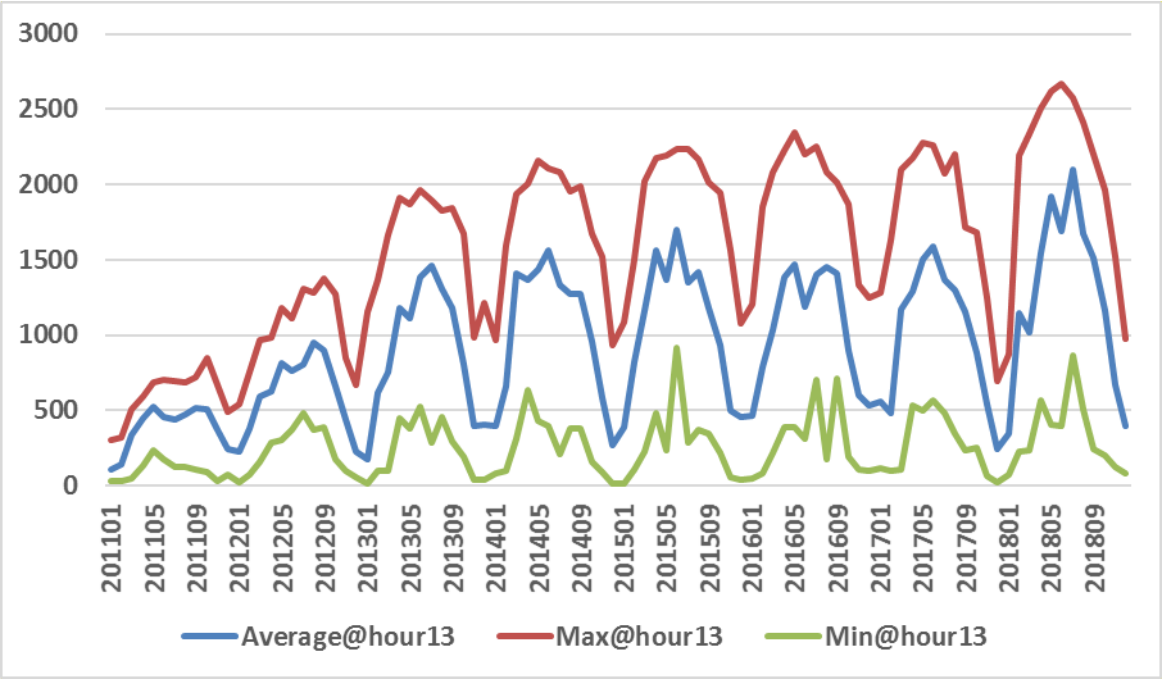


Figure 7: Daily pattern of the hourly average solar electricity generation (MW) of installed solar panels for 2013-2018.
Sources: Elia and CREG

12. This significant increase in 2018 is also confirmed by the total generated solar energy (Table 2). In 2018 3.6 TWh was estimated to be generated by solar panels in Belgium, an increase of 0.7 TWh or 20%. This is in sharp contrast to previous years when annual generated solar energy barely evolved after 2013. This shows that investments in the solar sector have resumed.

	Generated Solar Electricity (TWh)
2013	2.55
2014	2.94
2015	3.02
2016	2.90
2017	2.86
2018	3.58

Table 2: Generated electricity of solar origin 2013-2018
Source: CREG



13. Figure 8 shows the evolution of the maximum, average and minimum monthly generation at hour 13 of the day. The hours with the highest generation are observed in May and June. The estimated maximum generation rose to 2,668 MW in June 2018, compared to 2,277 MW in May 2017, an increase of almost 400 MW.

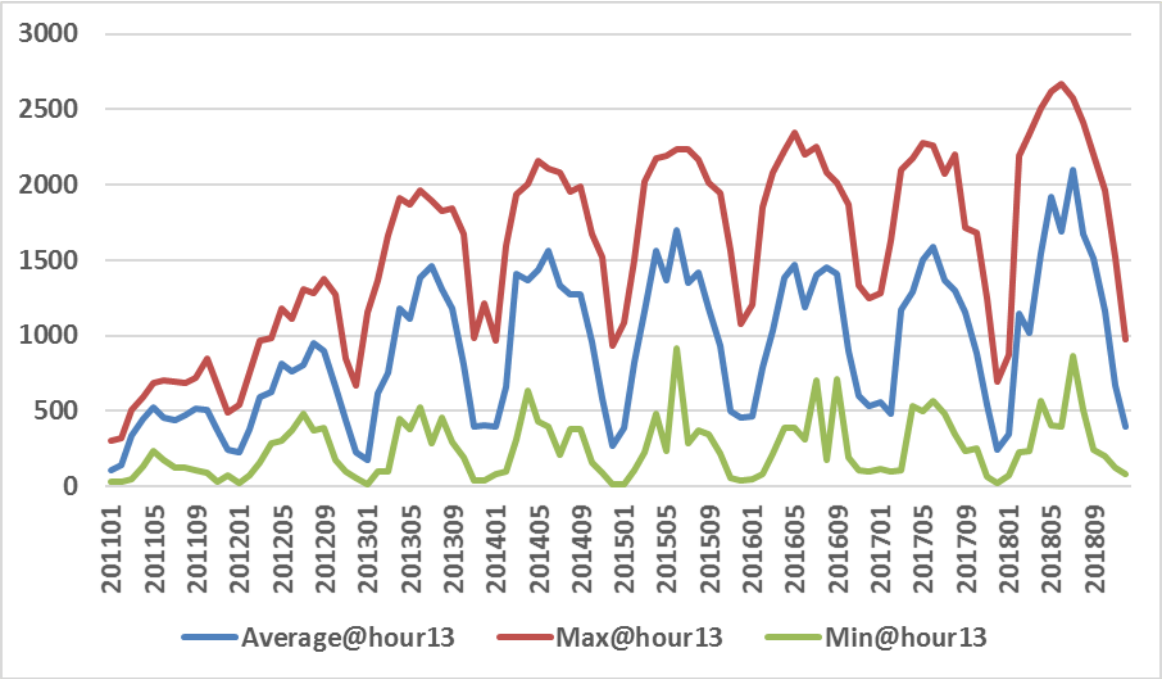


Figure 8: Evolution of the maximum, average and minimum monthly generation at the 13th hour of the day (midday)
Sources: Elia, CREG

14. From the figure above it is clear that solar electricity generation varies significantly. This variability could be perceptible in the event of higher variability of the Elia grid load in the middle of the day, since the solar generation connected at the distribution grid is seen as negative consumption by the Elia grid load.

Figure 9 shows a daily pattern of demand variability for 2007-2008 and for 2017-2018, measured using the standard deviation of the average demand per fifteen minute intervals (so for each year we calculate a standard deviation of 365 demand levels for the 96 quarters of the day).

Compared to 2007-2008, the variability of the demand in the middle of the day had increased by 150 to 300 MW in 2017-2018, in other words an increase of 15 to 30%. However, the variability in 2018 decreased slightly compared to the previous year. This decrease is seen throughout the whole day, so it probably cannot be attributed to a lower variability in solar generation.

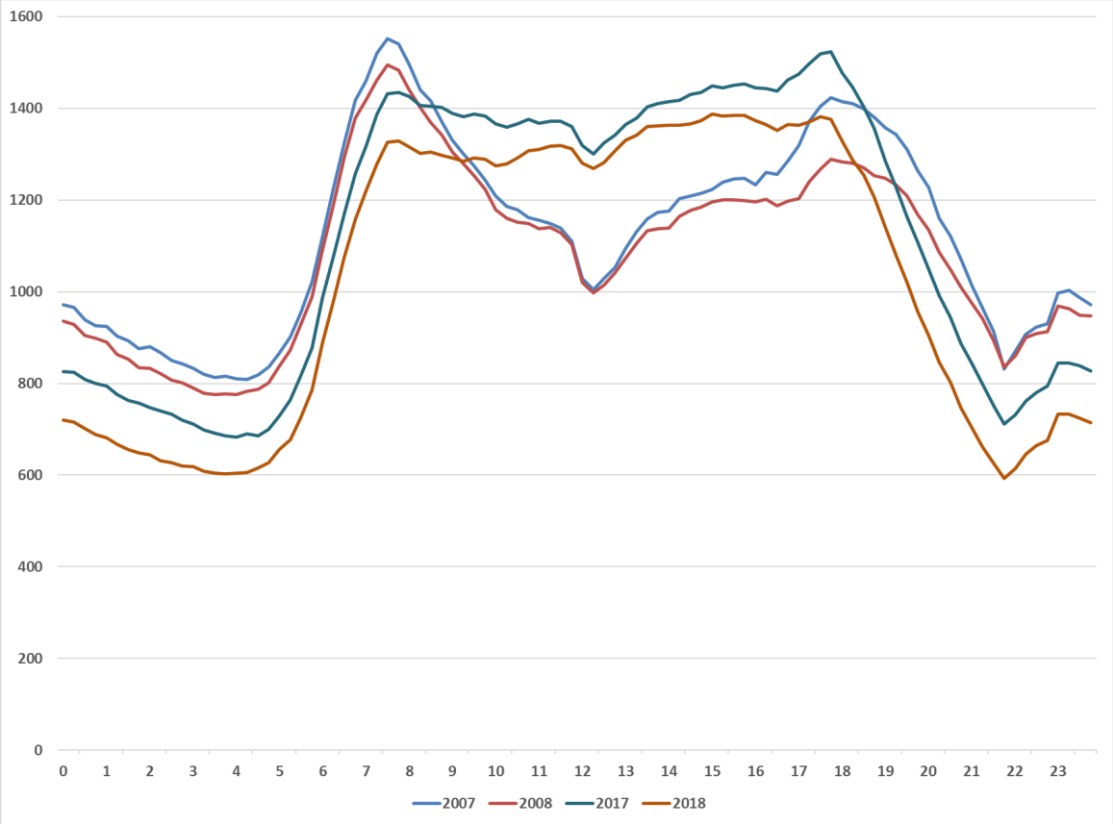


Figure 9: Standard deviation of the average demand per quarter of an hour on the network in the Elia control area (MW) for 2007-2008 and 2017-2018.
Sources: Elia and CREG

2. GENERATION

2.1. HISTORICAL BACKGROUND AND SIGNIFICANT EVENTS

15. Over the last decade, electricity generation in Belgium has been subject to various major changes. Investments in new conventional generation facilities fell significantly after the financial crisis of 2009, which also coincided with the start of a continuous fall in electricity demand. On the other hand, the installed capacity of investments in generation units using renewable energy sources is still increasing. This renewable capacity is characterised by relatively small marginal costs which affect the wholesale market price.

Conventional generation units have suffered from a fall in revenues due to declining running hours combined with lower market prices. The decline in running hours was primarily caused by lower electricity demand, increased renewable generation which precedes conventional units in the merit order and the low carbon value which led to a coal-before-gas scenario.

The elements described above led to a number of announcements of the temporary closure (mothballing) and definitive decommissioning of older, less profitable units. In addition to the decommissioning of some smaller, older units (turbojets, old co-generation), the closure of some CCGTs was also announced.

Since 2012, an increase in the unplanned unavailability of nuclear generation facilities has been observed.

The combination of several announcements regarding the mothballing and decommissioning of generation facilities, and this increase in the unavailability of nuclear plants, has led to concern about the security of electricity supply in Belgium. While in our neighboring countries, a reflection was carried out on the need to introduce a capacity remuneration mechanism, Belgium was confronted with a short-term security of supply issue. In 2014 and 2015 various measures were taken to cope with this issue: postponing the nuclear phase-out and setting up a mechanism of strategic reserves. Since winter 2014-2015, the mechanism of strategic reserves has been operational, although it has not been necessary to make use of this reserve.

In 2017, the profitability of CCGT plants further increased and several notifications of decommissioning of power plants were further postponed until 2019-2021.

Finally, in September 2018, Belgium was confronted with an unexpected additional unavailability of several nuclear plants, leaving only one nuclear unit available at certain times. Several measures were taken by market players and authorities to address this situation. A more detailed analysis is given in the CREG study (F)1950.

2.2. SPECIAL TOPIC : RELATION BETWEEN AGE AND AVAILABILILTY, PLANNED UNAVAILABILITY AND FORCED OUTAGE RATES

2.2.1. Objective of this analysis

16. In this chapter, the eventual effect of age on different parameters related to the availability of the major generation units, CCGT and nuclear, will be analysed. The effect on the following parameters will be analysed:

- Average availability rate (calculated as the number of days when the units were available over 365 (or 366) days);
- Planned unavailability rate;
- Forced outage rate.

This analysis will be based on data available (source: Elia) for the period 2007-2018. Ideally the analysis should be made over the total lifetime of the units, which is not feasible due to limited available data.

With the nuclear phase-out which is planned between 2022 and 2025, discussions are ongoing on how generation adequacy can be maintained. One of the questions raised is whether the existing units (this discussion primarily relates to CCGT-units) which are getting older, can be technically maintained in the system with a sufficient degree of availability. This special topic addresses this issue in a first high level analysis.

2.2.2. CCGT units

17. For the analysis of the effect of age on CCGT-units, Seraing and Vilvoorde will not be considered, as these units have been contracted since 2014 in the strategic reserve (out of the market) which was never activated. Hence, no forced outage rates have been available for these units since November 2014.

18. In 2018, the ages of the CCGT units analysed in this chapter ranges from 6 years for the most recent build to 24 years for the oldest CCGT still in operation.

19. The Figure below shows the availability of CCGTs according to their age. For the unit at Drogenbos, we see a deterioration of the availability over the last 3 years. Below we will analyse whether this is due to planned unavailability (for a major maintenance) or to forced outage. Based on these results, it can be noted that, except for the first years -sometimes with start-up problems-, no clear structural decrease of the availability of CCGTs can be observed.

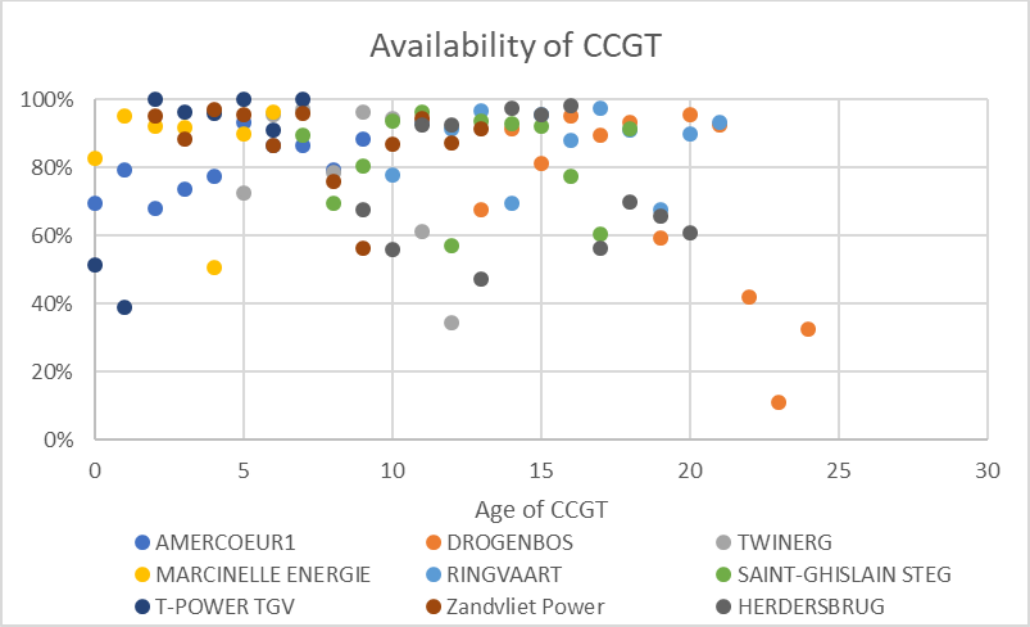


Figure 10: availability of CCGT according to age

The figure below shows the average forced outage rate for CCGTs according to their age. Clearly, no structural increase of the forced outage rates can be observed for older CCGT units.

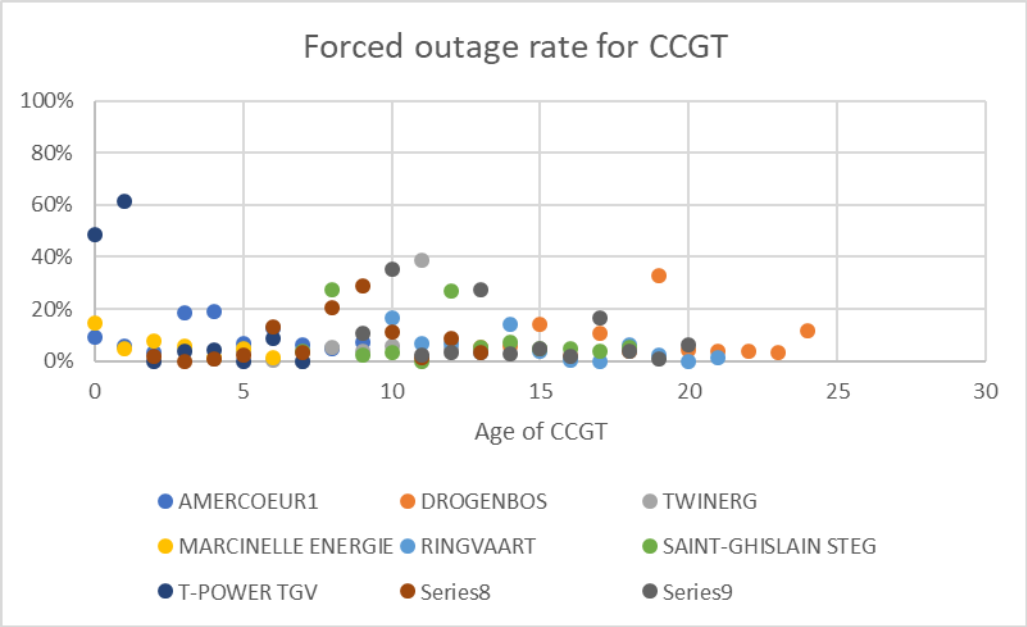


Figure 11: average forced outage rate of CCGTs

The figure below shows the planned unavailability rate for CCGTs. It explains that the lower unavailability of Drogenbos was caused by planned unavailability rather than due to forced outages.

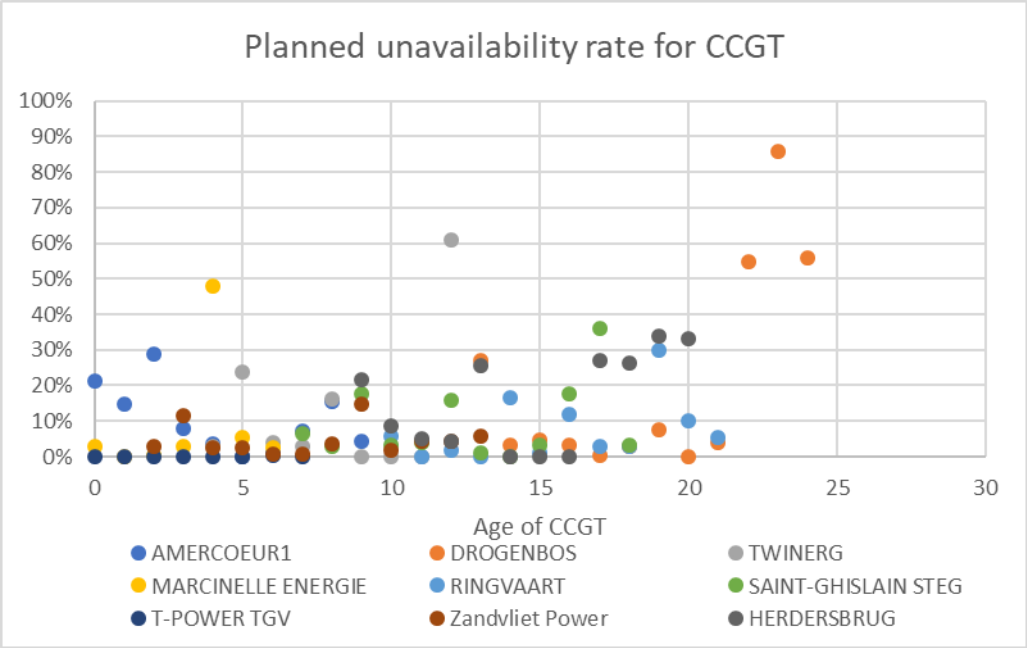


Figure 12: Planned unavailability of CCGTs

2.2.3. Nuclear units

20. The Figure below shows the availability of nuclear units according to their age. The decreasing availability of the nuclear units in recent years can be observed in this graph. It is questionable whether these unavailabilities need to be considered as "structural", as for example the concrete degradation should no longer be a cause of nuclear unavailability once repaired.

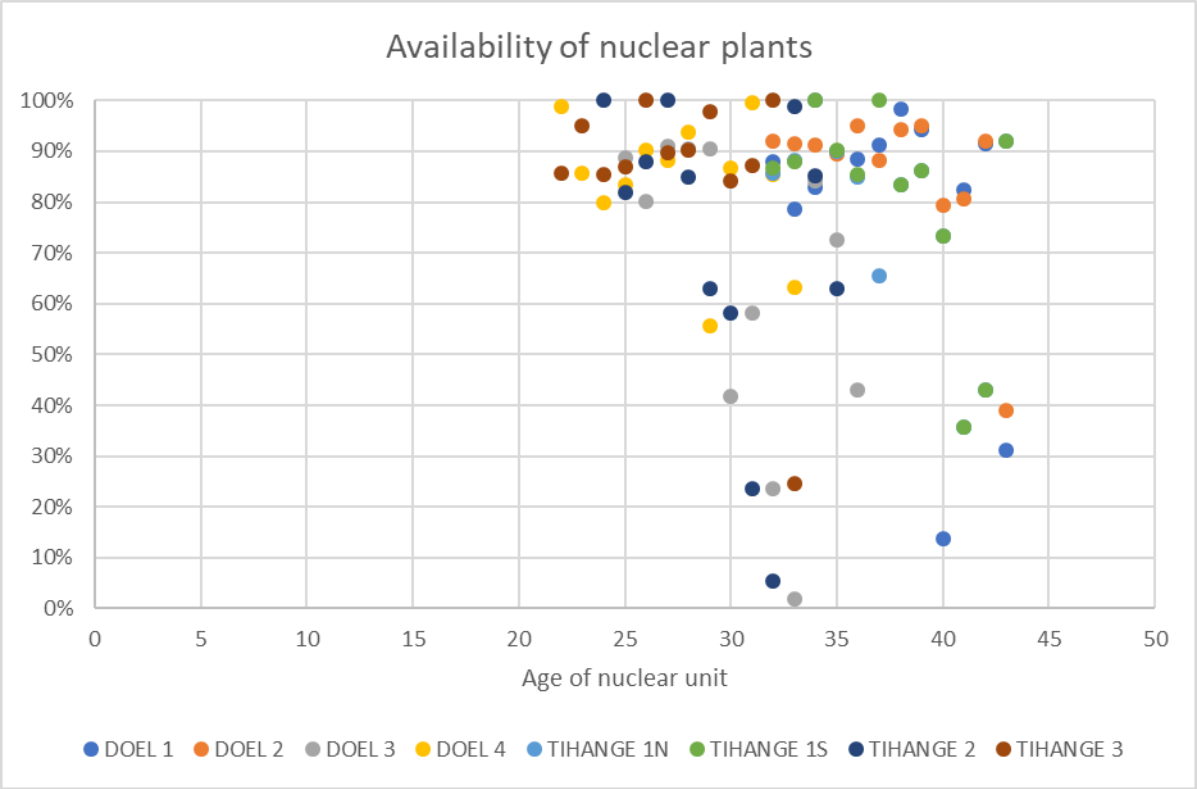


Figure 13: availability of nuclear plants

21. The two Figures below show that the limited nuclear unavailability in the recent years was mainly due to planned unavailabilities rather than due to forced outages.

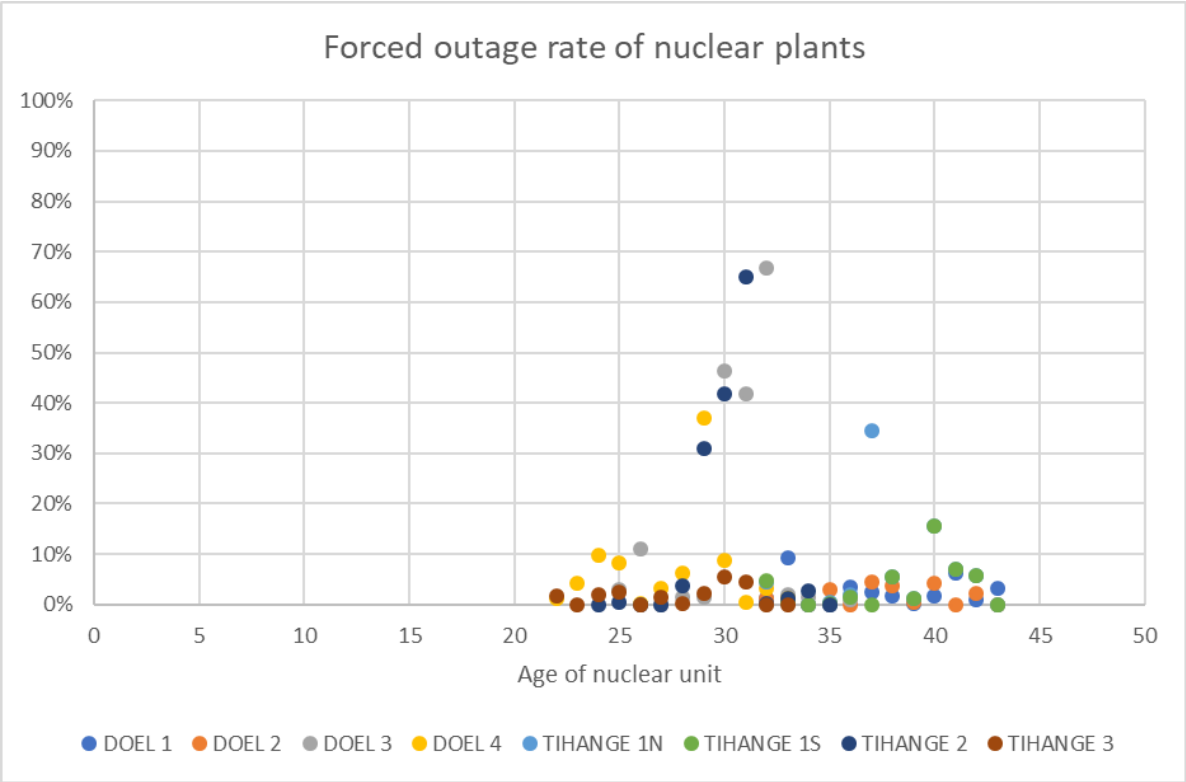


Figure 14: forced outage rate of nuclear plants

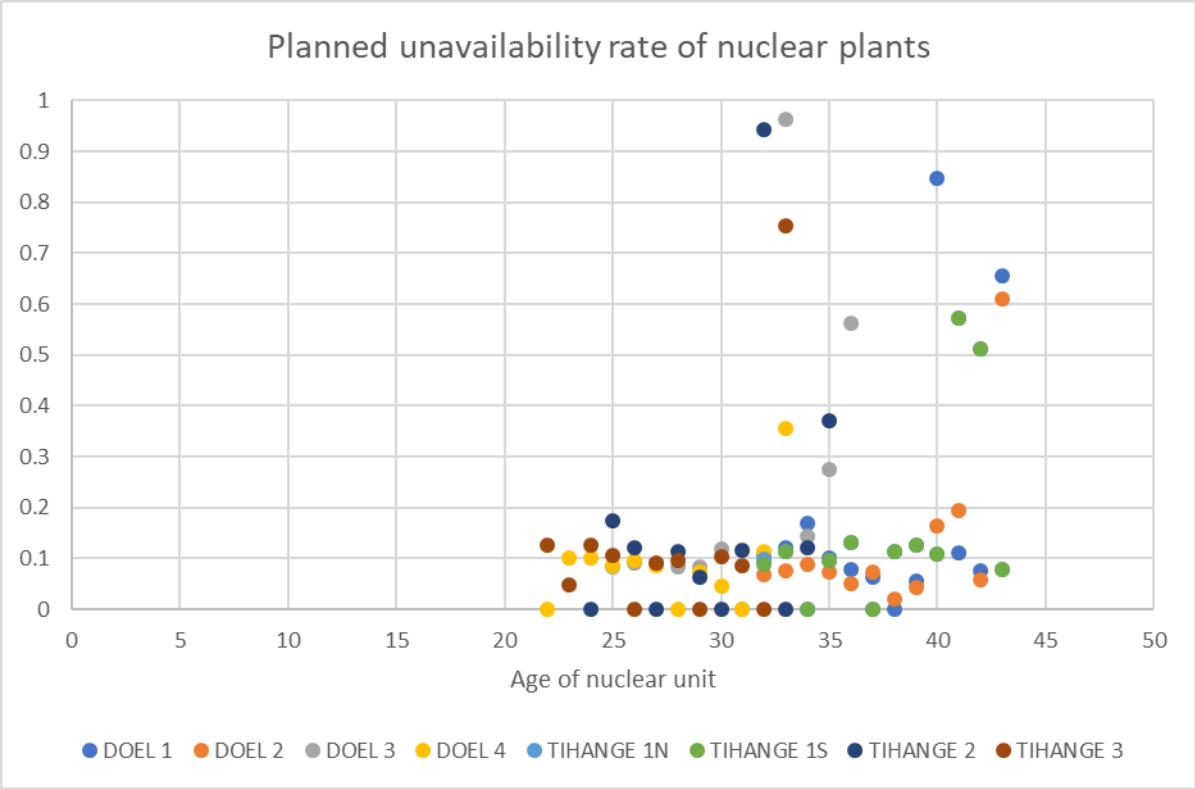


Figure 15: planned unavailability of nuclear plants

2.2.4. Conclusion

22. For CCGT units, decreased availability can be observed for older units, mainly linked to planned unavailibilities. No increased forced outage rate can clearly be detected for CCGTs.

For nuclear plants, recent years have been quite exceptional in terms of availability due to a number of non-structural events. As for CCGTs, no clearly increased forced outage rate can be detected for older nuclear units.

2.3. STATISTICS

2.3.1. Main characteristics of electricity generation in Belgium

23. At the end of 2018, the installed generation capacity (excluding mothballed capacity and capacity in strategic reserve) connected to the Elia grid amounted to 15.4 GW, compared to 14.1 GW in 2017. This significant increase in installed capacity is partially due to the commissioning of the Rentel offshore windfarm (309 MW) and the return to market of generation units which were contracted in strategic reserves in previous years (750 MW), complemented by different measures taken after the announcement of the additional nuclear unavailability for the winter period 2018-2019. Total electricity generated in 2018 by units connected to the Elia grid amounted to 57.8 TWh, compared to 70.2 TWh in 2017. Figure 16 shows the distribution of the installed capacity at the end of 2018 and the electricity generated in 2018 per fuel source.

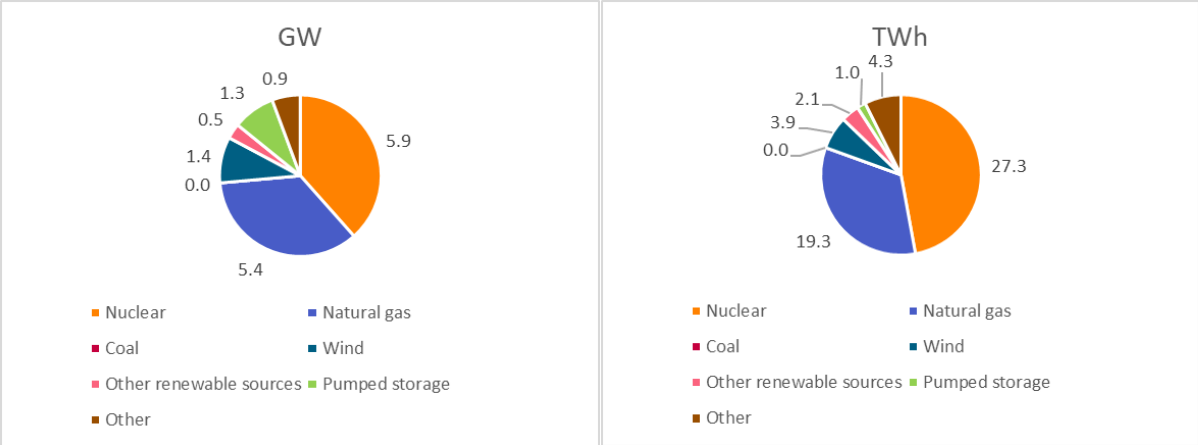


Figure 16: Installed capacity and electricity generation in 2018 by fuel source.
Sources: Elia, CREG

24. An estimate of the evolution of the installed capacity per fuel type connected to the Elia grid is shown in Table 3, considering the situation at the end of December. The share of the 7 nuclear power plants decreases to the level of 2013, due to the return to market of gas fired units which were contracted in the strategic reserve as from winter 2014-2015. The generation capacity shown is the capacity in the market: it does not include the installed generation capacity which is temporarily decommissioned and which might be contracted in the strategic reserve.

Type of fuel	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	5.8	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	36%	38%	38%	37%	39%	41%	41%	42%	42%	38%
Natural gas	5.6	5.8	5.9	6.3	5.6	4.7	4.6	4.6	4.5	5.4	35%	37%	37%	39%	37%	32%	32%	33%	32%	35%
Coal	1.4	0.9	0.8	0.7	0.5	0.5	0.5	0.0	0.0	0.0	9%	6%	5%	4%	3%	3%	3%	0%	0%	0%
Wind	0.1	0.3	0.3	0.5	0.7	0.9	0.9	0.9	1.1	1.4	1%	2%	2%	3%	5%	6%	6%	6%	8%	9%
Other renewable sources	0.2	0.4	0.6	0.4	0.4	0.4	0.4	0.4	0.4	0.5	1%	3%	4%	3%	3%	3%	3%	3%	3%	3%
Pumped storage	1.4	1.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	9%	9%	8%	8%	9%	9%	9%	9%	9%	8%
Other	1.4	1.0	1.0	0.9	0.8	0.9	0.9	0.8	0.8	0.9	9%	6%	6%	6%	6%	6%	6%	6%	6%	6%
Total	**16.0**	**15.8**	**15.8**	**16.0**	**15.3**	**14.6**	**14.5**	**14.0**	**14.1**	**15.4**	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Table 3: Evolution of generation capacity by fuel type (GW and %)
Source: Elia, CREG

An estimate of the evolution of the generated electricity per fuel type connected to the Elia grid for the last decade is shown in Table 4. The level of electricity generation in Belgium in 2018 is close to the level in 2013. The low values in the years 2014 and 2015 were mainly caused by the unavailability of several nuclear power plants.

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Nuclear	45.0	45.7	45.9	38.5	40.6	32.1	24.8	41.4	40.2	27.3	53%	53%	57%	54%	57%	54%	44%	59%	57%	47%
Natural Gas	29.4	30.2	24.1	21.9	18.1	16.8	18.5	18.0	18.8	19.3	34%	35%	30%	31%	26%	28%	33%	26%	27%	33%
Coal	6.3	4.9	3.7	3.3	3.0	2.2	2.2	0.4	0.0	0.0	7%	6%	5%	5%	4%	4%	4%	1%	0%	0%
Wind	0.2	0.4	1.0	1.1	1.8	2.5	2.9	2.7	3.2	3.9	0%	0%	1%	2%	3%	4%	5%	4%	5%	7%
Other Renewable	0.7	0.8	1.4	2.4	1.9	1.3	2.0	2.2	2.3	2.1	1%	1%	2%	3%	3%	2%	4%	3%	3%	4%
Pumped Storage	1.4	1.4	1.2	1.3	1.3	1.2	1.1	1.1	1.1	1.0	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Other	2.6	3.3	3.2	3.3	3.9	3.9	4.2	4.1	4.5	4.3	3%	4%	4%	5%	5%	6%	7%	6%	6%	7%
Total	**85.5**	**86.6**	**80.5**	**71.9**	**70.7**	**59.9**	**55.8**	**69.9**	**70.2**	**57.8**	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Table 4: Evolution of electricity generated by fuel type (TWh and %)
Source: Elia, CREG

25. Table 5 shows the evolution of the market shares of generation capacity connected to the Elia grid for different Access Responsible Parties (ARP) in the last decade. The table is based on end-of-year data.

The Herfindahl-Hirschman Index (HHI), which is an indication of market concentration, remains between 4000 and 6000. A market is considered to be highly concentrated when HHI-values are above 2000. There is still a long way to go to achieve a competitive market for generation in Belgium.

ARP	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Electrabel	12.1	11.4	11.0	10.7	9.9	9.9	10.2	10.2	10.1	10.6	76%	72%	70%	66%	65%	68%	71%	73%	72%	69%
EDF-Luminus	2.2	2.4	2.4	2.3	2.2	1.8	1.7	1.9	2.0	2.6	14%	15%	15%	14%	15%	12%	12%	14%	14%	17%
E.ON	1.2	1.5	1.5	1.5	1.5	1.1	0.6	0.0	0.0	0.0	8%	9%	9%	9%	10%	7%	4%	0%	0%	0%
T-Power	0.0	0.0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0%	0%	3%	3%	3%	3%	3%	3%	3%	3%
Others (<3%)	0.5	0.6	0.5	1.2	1.3	1.5	1.6	1.5	1.5	1.8	3%	3%	3%	7%	9%	10%	11%	11%	11%	12%
Total	**16.0**	**15.8**	**15.8**	**16.0**	**15.3**	**14.6**	**14.5**	**14.0**	**14.1**	**15.4**	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
											HHI	5970	5540	5170	4720	4460	4760	5160	5510	5420	5040

Table 5: Evolution of generation capacity by ARP (GW and %)
Source: Elia, CREG

26. The energy generated by units connected to the Elia grid by ARP is shown in Table 6. The share of generated electricity in 2018 decreased for Electrabel due to the high unavailability rate of nuclear plants, which are to a large extent owned by Electrabel.

ARP	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Electrabel	70.3	62.7	58.9	50.7	49.9	40.7	36.6	54.3	53.7	40.0	82%	72%	73%	71%	71%	68%	66%	78%	76%	69%
EDF-Luminus	12.2	12.2	9.3	8.5	8.6	7.6	7.3	7.2	8.5	9.7	14%	14%	12%	12%	12%	13%	13%	10%	12%	17%
E.ON	0.5	8.8	8.5	7.8	6.9	6.3	4.6	0.9	0.0	0.0	1%	10%	11%	11%	10%	11%	8%	1%	0%	0%
T-Power	0.0	0.0	1.0	0.5	0.4	1.4	2.2	2.6	2.5	2.4	0%	0%	1%	1%	1%	2%	4%	4%	4%	4%
Autres (<3%)	2.6	3.0	2.8	4.4	4.9	4.0	5.1	4.9	5.5	5.7	3%	3%	4%	6%	7%	7%	9%	7%	8%	10%
Total	85.5	86.6	80.5	71.9	70.7	59.9	55.8	69.9	70.2	57.8	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
										HHI	6868	5439	5599	5242	5223	4893	4559	6167	6011	5103

Table 6: Evolution of generated electricity by ARP (TWh and %)
Source: Elia, CREG

2.3.2. Nuclear generation

27. As previously mentioned, nuclear generation represents a major share of electricity generation in Belgium. Nuclear plants are geographically situated in two locations: Doel and Tihange. Table 7 provides an overview of the capacity and the ownership of the 7 nuclear plants.

Nuclear Plants		Doel 1	Doel 2	Doel 3	Doel 4	Tihange 1	Tihange 2	Tihange 3	Total	
Installed capacity		433 MW	433 MW	1006 MW	1039 MW	962 MW	1008 MW	1038 MW	5919 MW	100.0%
Ownership	Electrabel	100.0%	100.0%	89.8%	89.8%	50.0%	89.8%	89.8%	5021 MW	84.8%
	EDF			10.2%	10.2%	50.0%	10.2%	10.2%	898 MW	15.2%

Table 7: Ownership of nuclear plants
Source: Elia, CREG

Although several nuclear plants are jointly owned by Electrabel and EDF-Luminus, Electrabel manages daily operations and is the only Access Responsible Party for all units. Until the end of December 2015, E.ON had drawing rights on a part of the Electrabel share.

Electricity generation by nuclear plants has been extremely volatile in recent years due to the unplanned unavailability of several nuclear units. Figure 17 shows the monthly nominations for all nuclear power plants in Belgium. Nuclear generation in the last quarter of 2018 reached the lowest levels of annual generation of the past decade. On a year-to-year basis, nuclear generation was 13 TWh lower than in 2017. Over the past decade, nuclear generation was only lower in 2015 (25 TWh in 2015 compared to 27 TWh in 2018).

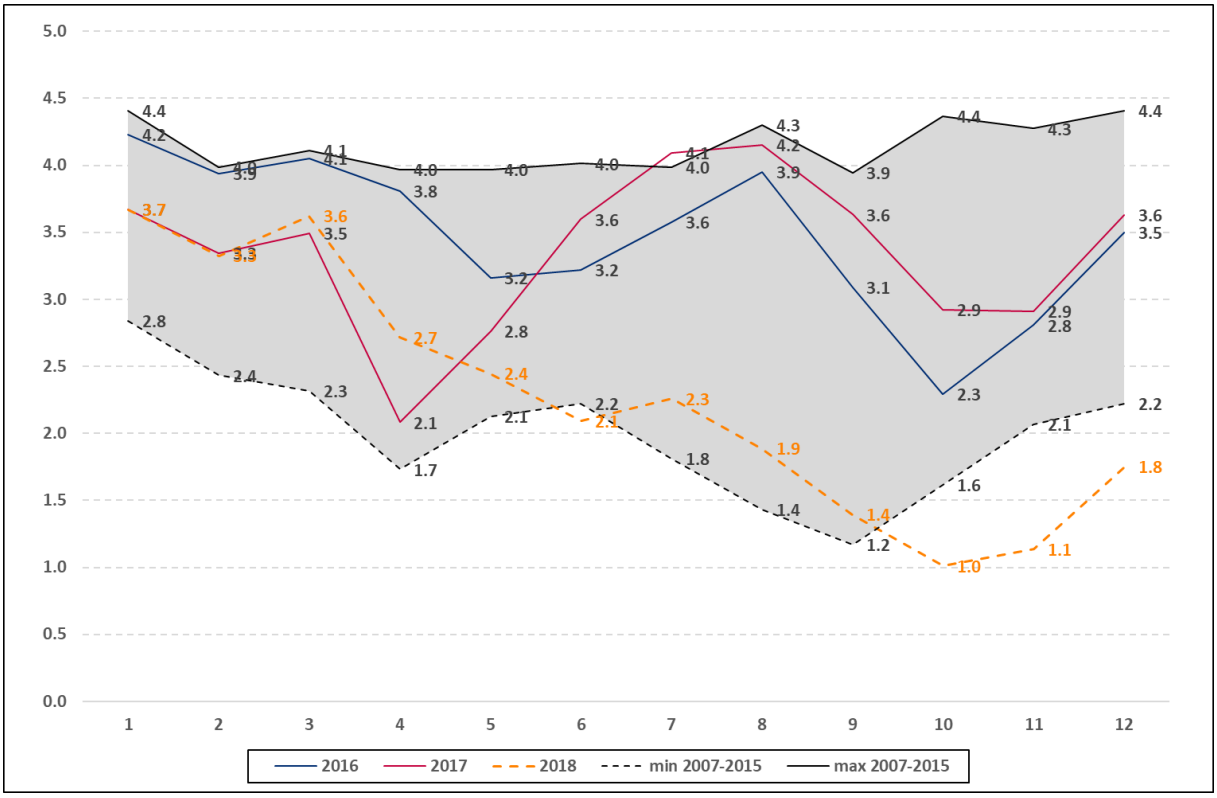


Figure 17: Monthly nominations for generation by nuclear power plants per year
Sources: Elia, CREG

28. The following figure shows for each year of the last decade the number of days of unavailability for each nuclear plant. The high unavailability of Doel 1, Doel 3 and Tihange 2 in 2014 and 2015 can be observed. On 7 September 2016, Tihange 1 was shut down because one building had been damaged during civil construction works. It remained unavailable until May 2017. In 2018, nuclear availability

was significantly reduced from September until December 2018, with sometimes only one 1GW-unit available.

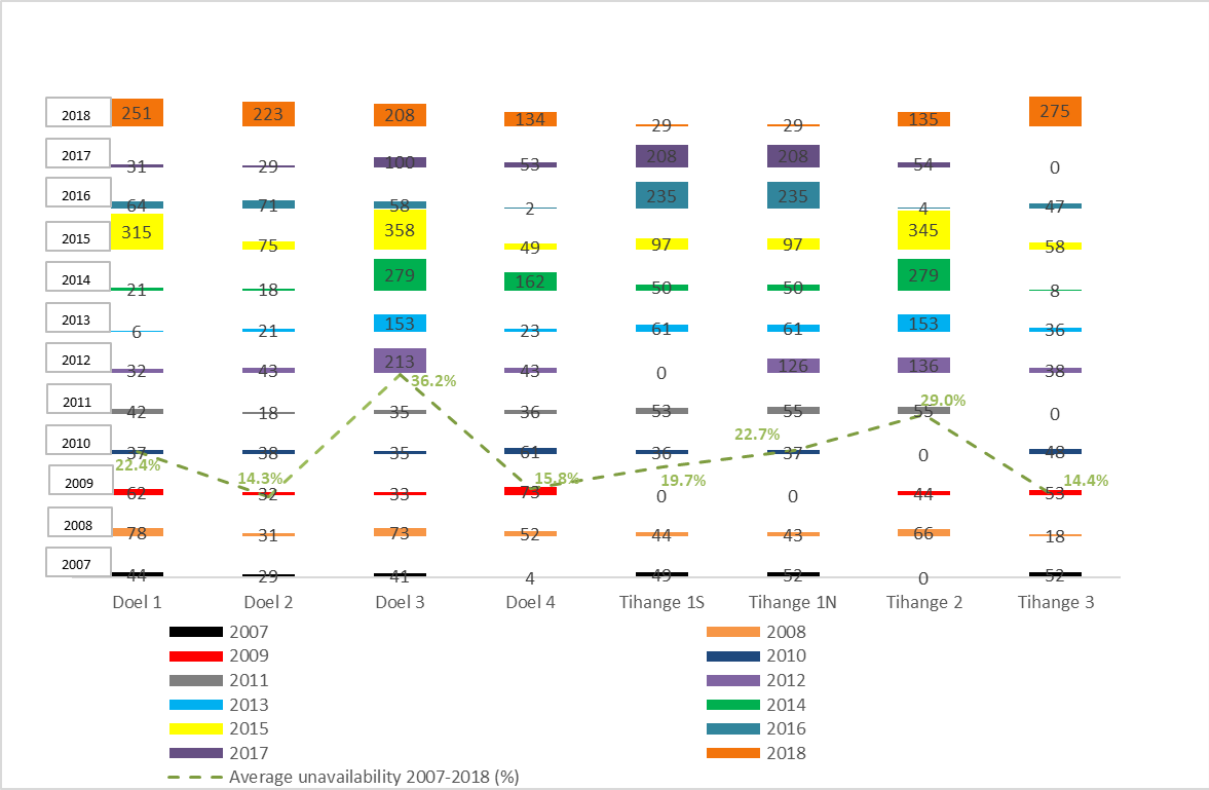


Figure 18: Number of days of unavailability of the 7 nuclear plants per year
Sources: Elia, CREG

2.3.3. Gas fired plants

29. Gas fired electricity generation in Belgium represents 33% of electricity generation in Belgium, behind nuclear generation (see also Table 4). Table 8 shows the ownership of the most important CCGTs in Belgium which are still active in the market.

Major CCGT's (± 400 MW) in Elia-zone		
Owner	**Unit**	**MW**
Electrabel	AMERCOEUR 1	451
Electrabel	DROGENBOS	460
Electrabel	HERDERSBRUG	465
Electrabel	SAINT-GHISLAIN	350
Electrabel 50% / BASF 50%	ZANDVLIET POWER	386
EdF Luminus	RINGVAART	365
T-Power	T-POWER	422
Direct Energy	MARCINELLE	413
EdF Luminus	SERAING	470
Total		3782

Table 8: Overview of major CCGTs in Belgium
Source: CREG

30. As shown in Figure 19, electricity generation by CCGTs had been decreasing since 2010. At the end of 2014 this trend was reversed and a further increase in generation by CCGTs was observed in 2016. The blue line represents the average minimum volume to be nominated in order to supply the secondary reserves (R2) of 140 MW.

In the 12 previous years, the number of CCGTs available in the market varied from 8 in 2007 to 11 in February 2012. From 2014 onwards, the number of CCGTs active in the market decreased from 11 to 8 in 2015. In November 2018, the CCGT of Seraing returned to the market (after being temporarily closed and contracted in the strategic reserve). The periods with different numbers of operational CCGTs are indicated by different shades of grey in Figure 19.

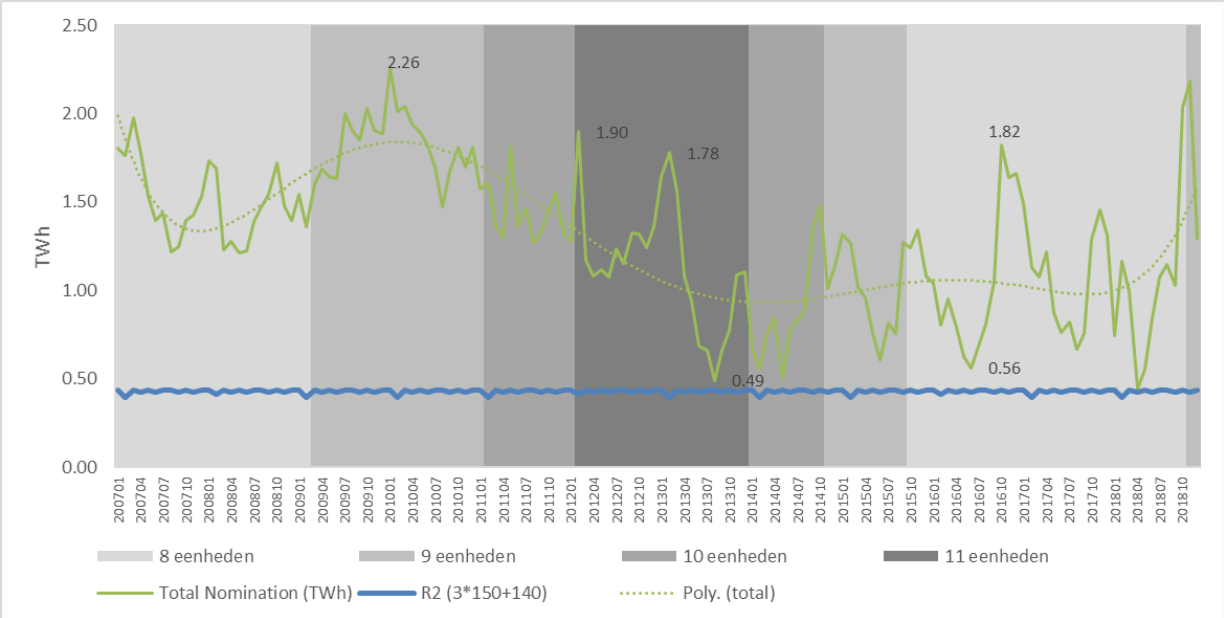


Figure 19: Total nominated energy in day-ahead of the Elia regulation zone CCGTs, per month, as well as an indication of the minimum average volume to be nominated for secondary reserves (blue line)
Sources: Elia, CREG

The high generation levels of CCGT at the end of 2016 and beginning of 2017 can be attributed to the unavailability of several French nuclear power units, and to the unavailability of Tihange 1. The high generation levels at the end of 2018 are also a consequence of the unavailability of nuclear plants in Belgium.

Table 9 gives, for each year, the total nomination for generation by CCGTs, the evolution of the generation in percentage, the average load factor for all CCGTs, the evolution of the load factor and the minimum and maximum load factor (which corresponds to the CCGT having relatively generated the least and most electricity). The decreasing trend of generation by CCGTs was reversed in 2015 and since 2016 there has been a slight increase. The fall of the load factor in 2018 is mainly due to the return to the market of Seraing for the last 2 months of 2018 (calculations need to be reviewed according to the number of months a unit is available). It should be noted that there is a big gap between the most profitable CCGT (which might be assumed to have the highest load factor) and the least efficient CCGT (with the minimum load factor). For obvious reasons, the load factors are impacted by unavailability of the unit.

(TWh)	Total electricity generation	Evolution (%)	Average load factor	Evolution (%)	minimum load factor	maximum load factor
2007	18.5		64%		46%	90%
2008	17.4	-6.1%	60%	-7.1%	34%	81%
2009	21.0	21.0%	63%	5.1%	31%	88%
2010	22.1	5.2%	67%	6.0%	44%	88%
2011	17.4	-21.4%	43%	-35.4%	4%	77%
2012	15.3	-12.3%	37%	-13.3%	6%	80%
2013	12.5	-18.3%	30%	-18.7%	3%	62%
2014	10.8	-13.3%	29%	-3.5%	2%	68%
2015	12.4	15.0%	37%	26.6%	5%	64%
2016	12.5	0.2%	42%	12.1%	1%	71%
2017	12.9	3.2%	45%	9.0%	0%	70%
2018	13.5	5.2%	37%	-17.6%	2%	65%
2007-2018	15.5	-27.0%	46%	-42.1%		

Table 9: Overview of electricity generated by major CCGTs in Belgium and their load factors
Source: Elia, CREG

3. ELECTRICITY TRADING

3.1. HISTORICAL BACKGROUND: SIGNIFICANT EVENTS

3.1.1. Founding of the Belgian power exchange

2005 The Belgian power exchange Belpex (now EPEX SPOT SE) was founded in July 2005 following the liberalisation of the European electricity market and the transposition into national law on 29 April 1999. The Royal Decree of 20 October 2005 established the rules concerning the creation, access and operation of the market for the exchange of energy blocks.

2006 On 11 January 2006, Belpex was designated as market operator responsible for organising the Belgian short term electricity market. Belpex became operational on 21 November 2006. The Belgian Transmission System Operator (TSO) Elia held a stake of 70%, the Dutch (APX) and the French (Powernext/EPEX Spot) power exchanges each held a stake of 10%, as did the Dutch TSO TenneT. The French TSO RTE also subsequently participated by taking over a 10% stake from Elia.

3.1.2. Organisation of the Belgian day-ahead market by Belpex

2006 Since its inception, the Belgian day-ahead market has been coupled with APX and Powernext. The trilateral market coupling (TLC) algorithm imposed a floor price of 0.01 €/MWh and a ceiling price of 3,000 €/MWh.

2010 On 9 November 2010, the market coupling was expanded to Germany and Luxembourg, thereby creating the Central West-European (CWE) price coupled region and revising the floor price of the algorithm to -3,000 €/MWh, while maintaining the ceiling price at its level. The CWE-region was also coupled by volumes with the Scandinavian power market consisting of Norway, Sweden, Denmark, Finland, and Estonia.

2011 On 1 April 2011, the BritNed-cable linked the Dutch power market with the power market in United Kingdom, thereby coupling the latter to the CWE-region (CWE+UK).

2014 The coupling of the CWE-region with the Scandinavian power market was revised from volume coupling to price coupling on 4 February 2014 to create the North Western European (NWE) market coupling. Besides the countries already mentioned above, Austria, Poland, Lithuania, and Latvia were also included in the NWE-region. The NWE-region was the first region that used the algorithm *Euphemia*, developed as part of the Price Coupling of Regions (PCR) project, to optimise the social welfare in day-ahead by determining the commercial flows between bidding zones and by fixing market prices in each bidding zone. The floor price was revised to -500 €/MWh while the ceiling price was maintained at 3,000 €/MWh.

On 13 May 2014 the South Western European (SWE) region consisting of Spain and Portugal was coupled with the NWE-region to form the Multi-Regional market coupling (MRC). Later that year, on 19 November 2014, Romania, the Czech Republic, Slovakia, and Hungary were coupled with each other (4M market coupling). During these developments, the CWE-region prepared to substitute the coupling method by means of Available Transfer Capacities (ATCs) with the flow-based market coupling method. While the former optimises social welfare in the coupled region by exchanging electricity between adjacent bidding zones as long as the ATC permits, the latter at once calculates and allocates

electricity exchanges between all bidding zones in the coupled region based on the order books of all coupled bidding zones and the technical limitations of the underlying electricity grid.

2015 The flow-based market coupling method was applied on 20 May 2015 (delivery 21 May).

3.1.3. Organisation of the Belgian intraday market by Belpex

2008 Belpex started organizing the continuous intraday market on 13 March 2008. The new CIM segment allowed market participants to act on the market until 5 minutes before delivery time to adjust their commercial position to changes in expected supply or demand in day-ahead.

2010 On 13 December 2010, the German TSOs Amprion and EnBW, together with the French TSO RTE, organized the implicit allocation of cross-border intraday capacity between the French and German bidding zone.

2011 The implicit intraday market coupling on the Belgian-Dutch border followed on 17 February 2011. On 14 March 2011 the implicit intraday market coupling was expanded to include Denmark, Norway, Sweden, Finland, Estonia and Germany.

2012 On 16 October 2012 the Austrian intraday market was created and immediately coupled with the French and German intraday markets.

Since 2012 it had been envisaged to create a pan-European intraday electricity market platform in the NWE-region. In June 2018, the first go-live of the single intraday coupling (SIDC) included 14 countries (Austria, Belgium, Denmark, Estonia, Finland, France, Germany, Latvia, Lithuania, Norway, The Netherlands, Portugal, Spain and Sweden). A second go-live with 7 further countries – Bulgaria, Croatia, Czech Republic, Hungary, Poland, Romania and Slovenia – was planned for 2019.

2013 In the meantime, the Swiss intraday market was coupled by an explicit mechanism on 26 June 2013.

2014 Until 30 November 2014, SPE (now EDF-Luminus) provided liquidity on the intraday market by offering 25 MW of electricity during 80% of the trading window at a price within a certain pre-determined price interval. No other company has engaged in market making activities since.

2018 In June 2018, the first go-live of the single intraday coupling (SIDC) included 14 countries (Austria, Belgium, Denmark, Estonia, Finland, France, Germany, Latvia, Lithuania, Norway, The Netherlands, Portugal, Spain and Sweden). A second go-live with 7 further countries – Bulgaria, Croatia, Czech Republic, Hungary, Poland, Romania and Slovenia – was planned for 2019.

3.1.4. Integration of the activities operated by Belpex in EPEX SPOT

2015 On 17 April 2015 Belpex, APX and EPEX SPOT announced the planned integration of their services with the aim of reducing barriers in power trading in the CWE region, including the United Kingdom. Market participants should therefore benefit from harmonized trading systems, one single set of rules and one admission process for the entire region, thereby reducing trading costs and lowering barriers to entry for new participants. Moreover, they should gain access to a wider range of products and benefit from best-of-both standards and reliable customer support. Overall, the integration would lead to more effective governance and further facilitate the creation of a single European power market fully in line with the objectives of the European electricity regulatory

framework. EPEX SPOT would then encompass Belgium, the Netherlands, France, Germany, Austria, Luxembourg and Switzerland. On 1 October 2015, APX and Belpex integrated their staff into the governance structure of EPEX SPOT. The operational integration occurred in multiple steps.

2016 On 31 December 2016, Belpex changed its corporate name to EPEX SPOT Belgium. The trading platform was migrated from Eurolight – as used by Belpex for day-ahead and intraday[4] trade – to the M7 platform (intraday trade) on October 4 2016 and the EPEX Trading System (day-ahead trade, ETS) on 24 January 2017. The migration of the intraday trading platform resulted in the Belgian intraday market being coupled with those of Germany, France, Austria, and Switzerland on October 5.

Before Belpex was fully integrated operationally, EPEX SPOT requested a modification of the market rules of Belpex. On 7 January 2016[5], 19 July 2016[6] and 22 September 2016[7] the CREG gave opinions on the requested modifications of the Belpex market rules. In these opinions, the CREG recommended any obligations or restrictions applicable to the market participant to be included in the market rules in accordance with the Royal Decree of 20 October 2005. The CREG specified in its opinions the impact of the ECC Clearing Conditions on the ability for a small market participant to access the market which led to the design and launch of the ECC Direct Clearing Participant model (DCPM) for participants in Belgium and the Netherlands on 1 September 2016, later expanded to France, Germany and the United Kingdom. In its opinions, the CREG also drew attention to the possible unintended consequences of imposing transaction limits, by third parties, on market participants. The CREG also recommended including objective criteria to assess a Manifest Error. The Minister of Energy approved the proposed modifications.

2017 After completing tests on 24 January, the migration of the Belgian and Dutch day-ahead markets from Euphemia to the Emission Trading System was completed. At the same time, EPEX SPOT substituted the free, daily communication of market results to market participants regarding the Belgian market to a paid service via its SFTP server[8].

2018 On 31 December 2018, EPEX SPOT Belgium merged with EPEX SPOT SE. The merger finalises the integration of EPEX SPOT and former APX Group companies. All rights and obligations of EPEX SPOT Belgium SA have been transferred to EPEX SPOT SE and any reference to EPEX SPOT Belgium SA or old APX is to be understood in conjunction with these changes.

3.1.5. Legal framework impacting Belgian power exchanges

2015 On 14 August 2015, Regulation (EU) No. 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (CACM) entered into force, requiring the Minister of Energy to nominate one or more Electricity Market Operators (NEMO) in Belgium before 14 December 2015.

On 7 October 2015, Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency (REMIT) came into force.

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[4] Until September 8 2016 the Elbas trading system was used

[5] http://www.creg.be/nl/publicaties/advies-a160107-cdc-1502 (available in Dutch and French).

[6] http://www.creg.be/nl/publicaties/advies-a160719-cdc-1549 (available in Dutch and French).

[7] http://www.creg.be/nl/publicaties/advies-a160922-cdc-1567 (available in Dutch and French).

[8] Market prices can still be freely consulted on the Transparency Platform of ENTSO-E, under the tab 'Transmission': https://transparency.entsoe.eu/

2016 In relation to CACM, on 14 January 2016 the CREG gave two opinions, one for the nomination of Belpex[9] as NEMO and one of the nomination of Nord Pool[10] as NEMO, following requests by the Minister of Energy received on 7 December 2015. Both power exchanges have been successfully nominated as NEMO.

In relation to REMIT, the CREG received 3 formal notifications. In total, 7 cases were analysed during the year and 1 was closed or transferred to another authority.

2017 In relation to CACM, on 29 June 2017 the CREG published its decision on the application of EPEX SPOT Belgium and Nord Pool SA and all designated electricity market operators for the revised plan concerning the joint performance of MCO functions.

In relation to market monitoring activities, on 24 May and on 17 July, following enquiries from market participants, the CREG published two reviews explaining the day-ahead market results on 6 April, 10 April, and 1 May.

In relation to REMIT, the CREG received 7 formal notifications. In total, 13 cases were open for analysis during the year and 6 were closed or transferred to another authority.

3.1.6. Organisation of the Belgian day-ahead and intraday markets by EPEX SPOT Belgium

2016 On 14 January 2016 the CREG gave two opinions, one for the nomination of Belpex[11] as NEMO and one of the nomination of Nord Pool[12] as NEMO, following requests by the Minister of Energy received on 7 December 2015. Both power exchanges have been successfully nominated as NEMO.

In 2016, on 5 days, including 4 in November, a second auction was triggered, the majority due to high prices in hour 17 and/or 19. Second auctions are triggered if the market clearing price in a bidding zone exceeds 500 €/MWh. The impacted markets were Belgium and the United Kingdom. The risk of partial decoupling existed on 7 days. Besides the 4 days in November, 2 days in September and 1 in May were impacted. The market coupling results were delayed on 10 days, suggesting that it took the market clearing algorithm more than 10 minutes to calculate a feasible market clearing price, of which 7 are related to the causes described above. On 19 October 2016, version 9.5 of Euphemia was released.

2017 From 11 January onwards, the upper threshold to trigger a second auction was raised from €500/MWh (£500/MWh in the UK) to €1,500/MWh (£1.500/MWh in the UK). The lower threshold remains at €-150/MWh (£-150/MWh). No second auctions were triggered in 2017 and on 1 day the publication of market results was delayed, suggesting that it took the market clearing algorithm more than 10 minutes to calculate a feasible market clearing price.

Intraday trading was restricted on several occasions. On 9 January, from 2:20 to 3:11, on 10 January from 15:55 to 19:00, and on 24 January from 15:55 to 19:00 (advanced to 18:05) cross-border trading with the Netherlands was restricted. On 30 January from 19:40 until 31 January at 00:15, all local intraday trade was suspended.

On 14 November 2017 version 6.0 of the M7 trading system was deployed between 16:30 and 23:25.

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[9] http://www.creg.be/nl/publicaties/advies-a160114-cdc-1501 (available in Dutch and French).
[10] http://www.creg.be/nl/publicaties/advies-a160114-cdc-1503 (available in Dutch and French).
[11] http://www.creg.be/nl/publicaties/advies-a160114-cdc-1501 (available in Dutch and French).
[12] http://www.creg.be/nl/publicaties/advies-a160114-cdc-1503 (available in Dutch and French).

Finally, on 17 July Nord Pool spot was appointed market operator for the exchange of energy blocks by Ministerial Decree, after having filed a request on 16 May.

2018 The cross-border intraday initiative XBID was successfully implemented on the European intraday markets on 12 June with first deliveries on 13 June.

From July 2018, 15-minute continuous intraday trading was introduced on the Belgian and Dutch local power spot markets. The first day of trading was 10 July 2018.

3.2. SPECIAL TOPIC: PROFITABILITY OF COMBINED CYCLE GAS TURBINES

31. Combined Cycle Gas Turbines (CCGT) plants are relied on in Belgium to provide peak supply. Since 2014 concerns have arisen in the electricity sector on the profitability of CCGT plants and subsequently questions have been raised regarding the role CCGT plants can have in the future system with energy-only remuneration. This special topic looks at the historic profitability of CCGT plants, explains the background of the above-mentioned concerns and describes how the fundamentals have changed for the profitability of CCGT plants since 2014.

32. A CCGT plant is valorised by turning gas into electricity. The electricity is sold on the electricity market while the gas needed to generate the electricity is procured from international gas markets. By transforming energy from gas molecules to electrons, CO_2 is emitted in the air. Since 2005, following the launch of the Emission Trading System (ETS) in the European Union, emitted CO_2 needs to be offset by CCGT plant owners by purchasing sufficient certificates. A CCGT plant can generate electricity at a profit if the price for electricity is larger than the cost for procuring the equivalent volume of gas and the equivalent number of certificates to offset CO_2 emissions. The difference between the electricity price and the equivalent cost components is referred to as the Clean Spark Spread (CSS): if positive, the CCGT plant can make a profit.

The CCGT plant is thus valorised by selling electricity on the electricity markets and buying a volume of gas and a number of CO_2 certificates to generate the sold volume of electricity when the CSS is positive. When the CSS is negative, the CCGT plant can also be valorised by buying electricity on the electricity markets and selling an equivalent volume of gas and a number of CO_2 certificates. By selling electricity the commercial position of the CCGT plant is increased to deliver electricity during the time period for which the electricity is sold. Purchasing electricity decreases the commercial position of the CCGT plant. Depending on the sign of the CSS, the CCGT plant can be continuously valorised, either by selling electricity when the CSS is positive or by purchasing electricity when the CSS is negative.

33. Electricity, gas and CO_2 markets are all open for trade 3 years ahead of delivery so that theoretically every day up to real time the CCGT plant can be valorised. In practise, the commercial position is not frequently altered as the delivery by the CCGT plant of the final commercial position needs to be technically feasible and as various risks exist when trading, including forecast, commercial and financial risks. For these reasons, this special topic assumes two valorisation steps. On each of the three year-ahead markets, electricity is assumed to be sold (not purchased) as a first step. The second step assumes either selling or buying electricity on the day-ahead market, whichever is more profitable given the sign of the CSS.

34. The profitability of the first step (selling electricity and buying an equivalent volume of gas and number of CO_2 certificates) each year is indicated by the average positive CSS during the year and the number of days with a positive CSS (Figure 20). Note that the figure indicates the year of delivery, not the year of transaction. The higher both metrics, the higher the profitability of the first step.

Until 2011, for each year-ahead product, both the average positive CSS and the number of days during which the CSS is positive are high, indicating a high valorisation of the CCGT plant. In 2012, the 1-year-ahead product becomes unprofitable, joined by the 2-year-ahead product in 2013 and the 3-year-ahead product in 2014. Starting from 2015, the number of days during which the 1-year-ahead product is profitable increases gradually, reaching pre-2012 levels for delivery in 2019. The 2-year-ahead product shows signs of improvement as well, reaching almost 150 days of positive CSS in 2019.

The average positive CSS remains subdued compared to pre-2012 levels. In 2018, a 1-year-ahead CSS of €4/MWh is attained while the CSS exceeded €14/MWh in 2008 to 2010. No trend is visible for the other two year-ahead products.

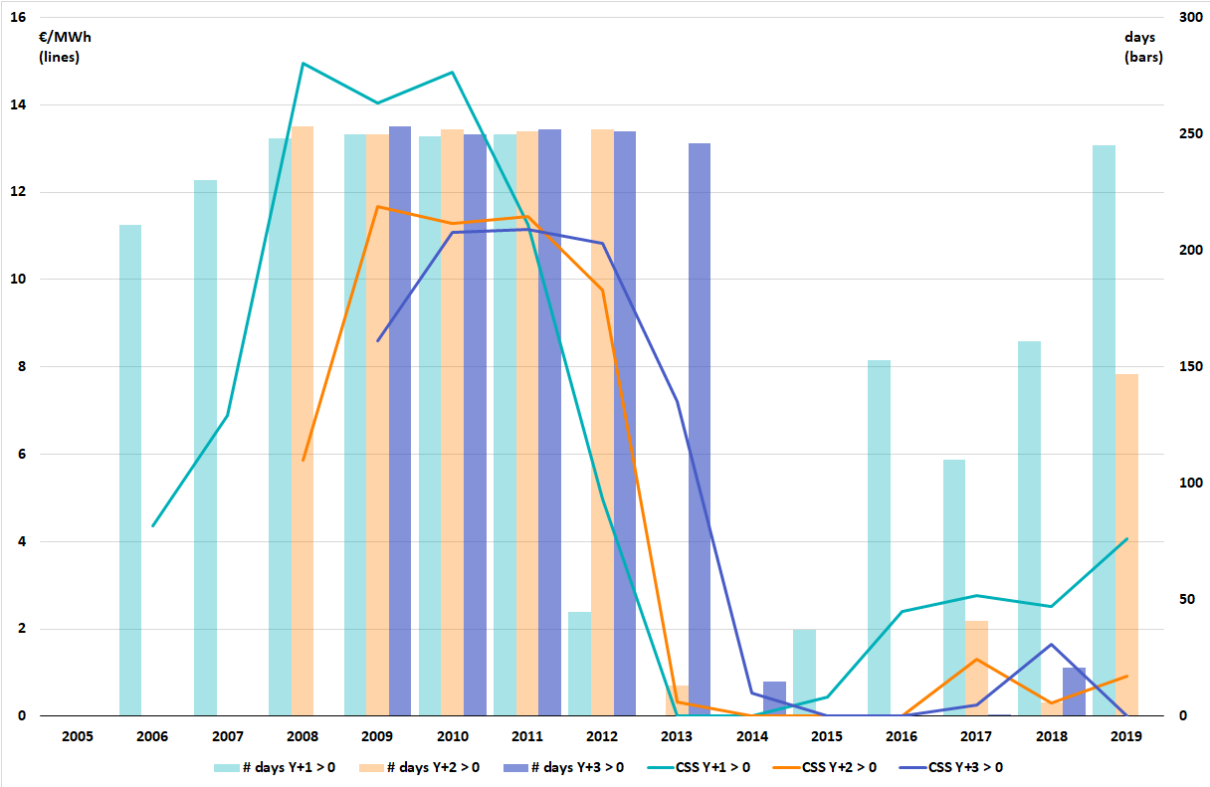

Figure 20 – Average positive Clean Spark Spread (lines, left axis) and number of days with positive Clean Spark Spread (bars, right axis), per year, for the three year-ahead wholesale electricity products with delivery in Belgium
Source: CREG based on data received from EPEX SPOT, EEX

35. Based on the first step, the majority of the capacity of the CCGT plant is sold on forward markets in the years 2009 to 2012. During 2014 and 2015 almost no capacity is sold on forward markets. An intermediate amount is sold in the remaining years. This means that in the years 2012 to 2018, a CCGT plant could be further valorised on the spot market by selling electricity while during the years 2009 to 2012 and 2016 to 2018 a CCGT plant could be further valorised by purchasing electricity.

36. The profitability of selling electricity in the second step each year is indicated by the average positive CSS during the year and the number of hours with a positive CSS (Figure 21). The figure distinguishes between an early off-peak period (hour 1 to hour 8 each day), a peak period (hour 9 to 20 each day) and a late off-peak period (hour 21 to 24 each day). The higher both metrics, the higher the profitability of selling electricity in the second step.

Since 2011, the number of hours with positive CSS have declined. The decline is stronger during each of the off-peak periods compared with the peak period. Starting from 2014, the average number of hours with positive CSS increases. A pullback is visible in 2018. The average positive CSS shows a similar curve with the exception for 2018, where the average positive CSS for the late off-peak period continued to rise while the average positive CSS for the other two periods fell.

Consequently, from 2015 onward, the unsold capacity of the CCGT plant on forward markets can increasingly be valorised on the day-ahead market. In 2018 however, the number of hours with positive CSS during the early off-peak period falls sharply.

37. The profitability of buying electricity in the second step each year is indicated by the average negative CSS during the year and the number of hours with a negative CSS (Figure 22). The figure distinguishes between an early off-peak period (hour 1 to hour 8 each day), a peak period (hour 9 to 20 each day) and a late off-peak period (hour 21 to 24 each day). The higher both metrics in absolute value, the higher the profitability of purchasing electricity in the second step.

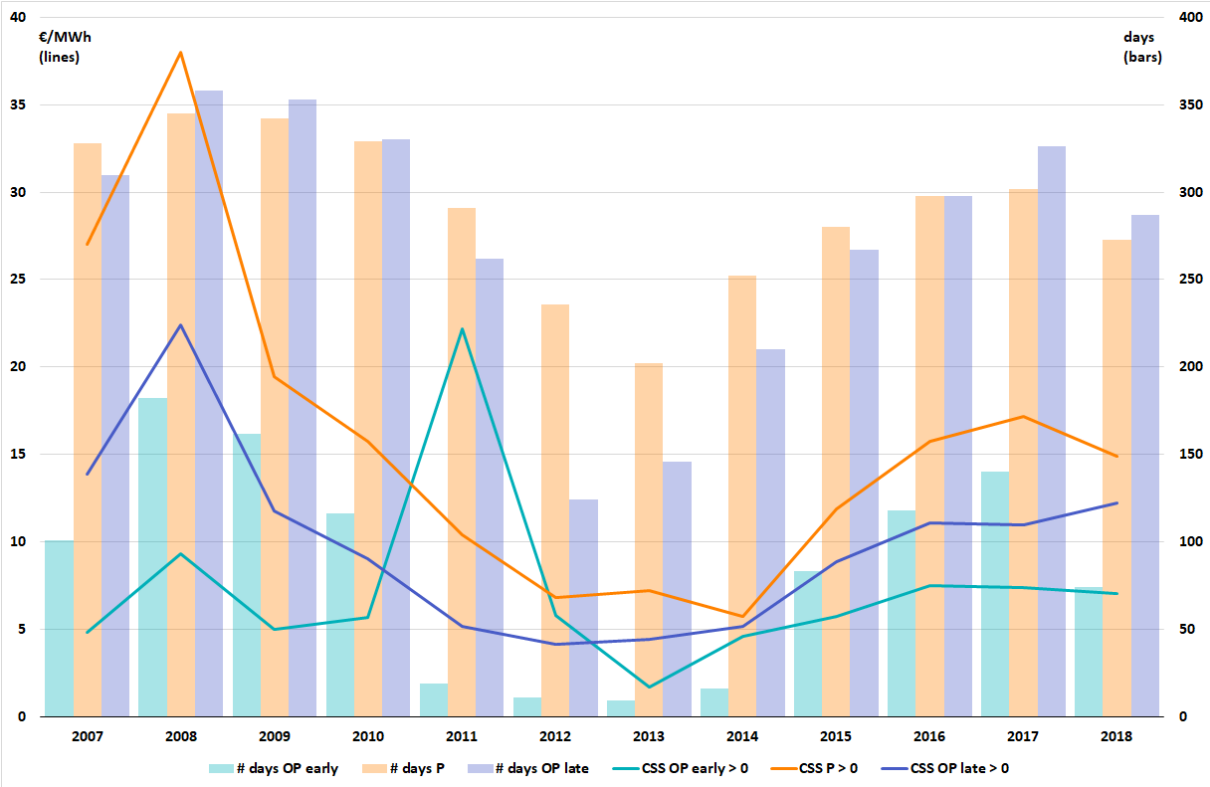

Figure 21 – Average positive Clean Spark Spread (lines, left axis) and number of days with positive Clean Spark Spread (bars, right axis), per year, for the three peak/off-peak periods of the day-ahead wholesale electricity product with delivery in Belgium
Source: CREG based on data received from EPEX SPOT, EEX

Based on the first step, the majority of the capacity of the CCGT plant is sold on forward markets in the years 2009 to 2012. From 2009 onward repurchasing the sold capacity on forward markets becomes increasingly profitable. Valorising the CCGT plant by repurchasing electricity is less attractive from 2016 onward except during the early off-peak period.

38. Combining all these observations, the evolution of the operational profitability of a CCGT plant can be derived. For illustrative purposes, an average CCGT[13] is assumed (Figure 23).

The CCGT plant is largely valorised on the forward markets from 2007 to 2011. Assuming most of the capacity is sold, the valorisation in the second step will be concentrated around the ability to (partially) repurchase the sold capacity on forward markets. Given the decreasing value of the negative CSS and the increasing number of hours with negative CSS, the valorisation of the second step will increase from 2007 to 2011, especially during the early off-peak periods.

In 2012 and 2013 the opportunity to valorise the CCGT plant on forward markets diminishes and as a result a lower capacity is sold. This will result in not only a reduced valorisation in the first step, but also a reduced valorisation in the second step from buying electricity, as less capacity has been sold on forward markets and thus less capacity can be repurchased than in previous years. Alternatively, the valorisation of the second step from selling electricity during the peak and late off-peak periods is still possible. Combining both buying and selling electricity in the second step more frequently increases the additional costs (start-up costs or must-run costs) as the CCGT plant is modulated between the early off-peak period and the other two periods during the day.

[13] An average CCGT plant is assumed to be modulable between 150 MW and 400 MW, its maximum capacity. It has an efficiency of 50% and a start-up cost of a fixed 2,500 euro plus a variable cost equalling 700 MWh_{th} gas consumption.

In 2014 and 2015, there was almost no opportunity to sell electricity on forward markets. Consequently, the capacity of the CCGT plant is mainly valorised by selling electricity in the second step. Since few early off-peak periods are profitable, the CCGT plant is also frequently modulated causing the additional costs to increase. As the average positive CSS is low, these additional costs offset a significant part of the gain. In 2014, for example, the average gain was 69 euro/MW during each peak period. The CCGT plant of 400 MW would gain on average 27.550 euro by starting up each peak period with positive CSS. The start-up costs of the plant however lies around 17.000 euro, thereby netting only 39% of its gain as an operational profit before including O&M costs or other fixed costs.

Starting from 2016, the opportunity to sell electricity on forward markets returns gradually: in 2016 the 1-year-ahead product is profitable, adding a profitable 2-year-ahead product in 2017 and again the 3-year-ahead product in 2018. As a result, the capacity sold will increase, reducing the valorisation potential of the CCGT plant by selling electricity but increasing its potential for repurchasing the electricity. As in 2017 the average positive CSS is largest and given the high number of hours with positive CSS over all three periods, the CCGT plant would see its highest gain and lowest offset caused by additional costs in 2017.

In 2018, the gain by selling electricity in the second step is reduced because most capacity has been sold in forward markets (and less capacity is additionally sold in the second step). The CCGT is further valorised by repurchasing electricity during the early off-peak period in the second step. Given the mainly positive CSS during the peak period and late off-peak period, the CCGT plant needs to be modulated frequently, thereby incurring additional costs and dampening the operational profitability of the CCGT plant with respect to 2017.

While the profitability of the 3-year-ahead product disappears in 2019, the other two year-ahead products increase significantly in profitability.

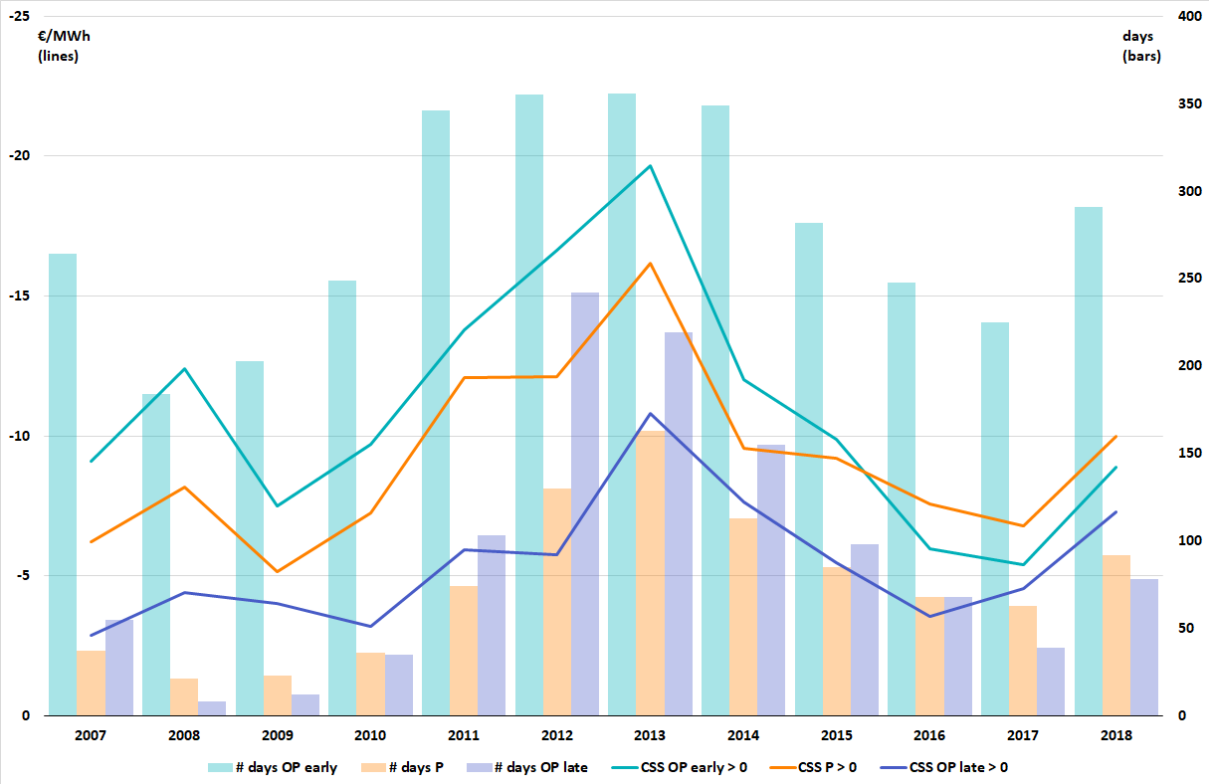

Figure 22 – Average negative Clean Spark Spread (lines, left axis) and number of hours with negative Clean Spark Spread (bars, right axis), per year, for the three peak/off-peak periods of the day-ahead wholesale electricity product with delivery in Belgium
Source: CREG based on data received from EPEX SPOT, EEX

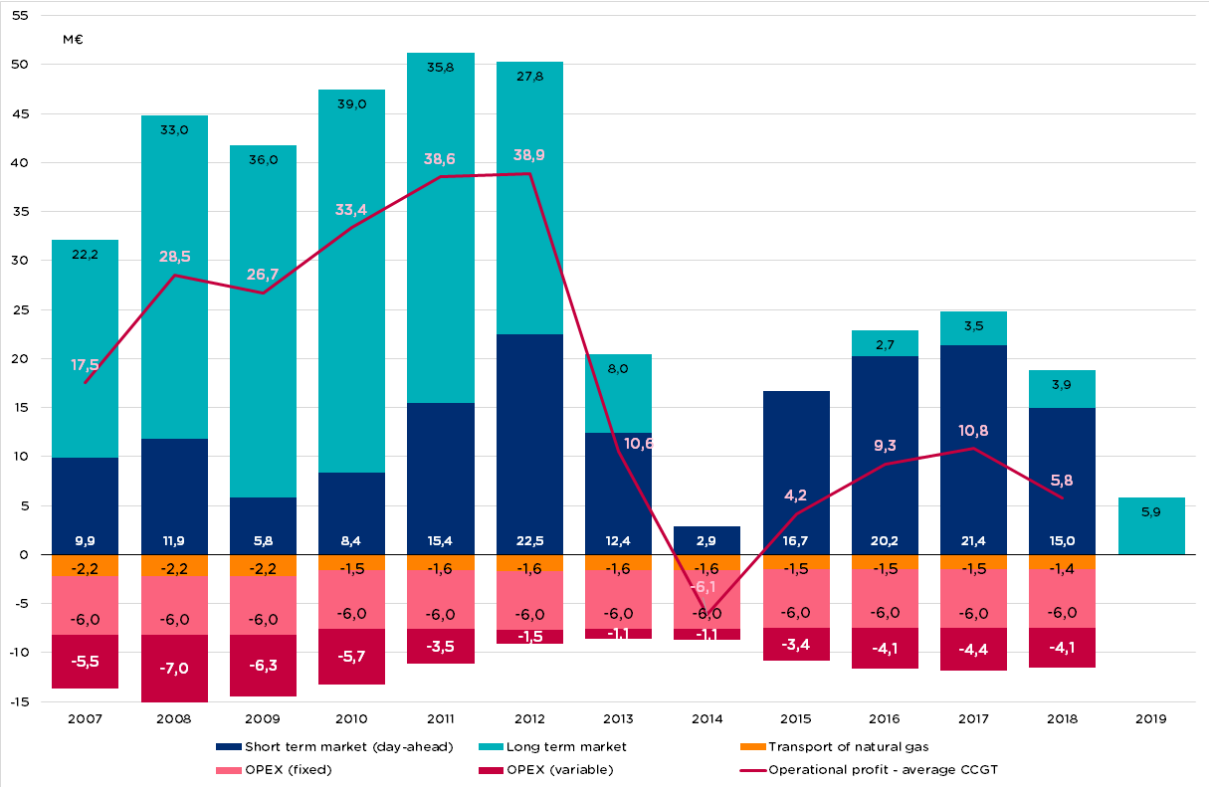

Figure 23 – Operational profitability of an average CCGT plant with indicated fixed and variable costs, from 2007 to 2019. Source: CREG

3.3. STATISTICS

3.3.1. Day-ahead wholesale electricity market for delivery in Belgium

39. The yearly averaged day-ahead wholesale electricity price in Belgium increased by 24% to 55.3 €/MWh (Figure 24). A year-on-year increase in prices was also observed in the other bidding zones in the CWE region and signals that, on average in 2018, the whole region – not only Belgium – relied on more expensive supply to meet demand. Yearly averaged prices in the Netherlands and Germany increased more than 30% year-on-year compared with 12% in France. The Austrian bidding zone, split from the German bidding zone since the first of October 2018 (delivery date), had an average price of 59,9 €/MWh during this period.

40. The monthly averaged day-ahead prices in Belgium are significantly elevated during the fourth quarter of each year (Figure 25). In both 2017 and 2018, an increase of 40% is observed between the fourth quarter and the other quarters of the same year. Increases are also observed for the other bidding zones in the CWE region, although with different magnitudes: 20% for the Netherlands and 37% for the France. The price increases fluctuate every year for Germany, with a 28% increase in 2018. These observations indicate a structural shift of the supply-demand equilibrium throughout the year, ranging from sufficient regional supply and cross-border capacity to cover all demand in the CWE region during spring and summer, to a situation where local supply and cross-border capacity are scarcer to meet demand.

Besides increasing demand in the CWE region during the winter period, the shift of the supply-demand equilibrium was driven by lower nuclear power plant availability in Belgium. A lower amount of baseload capacity increases prices during summertime, when the marginal cost of baseload power

plants set the price. It also increases prices during wintertime because peak units are more frequently called upon to meet demand.

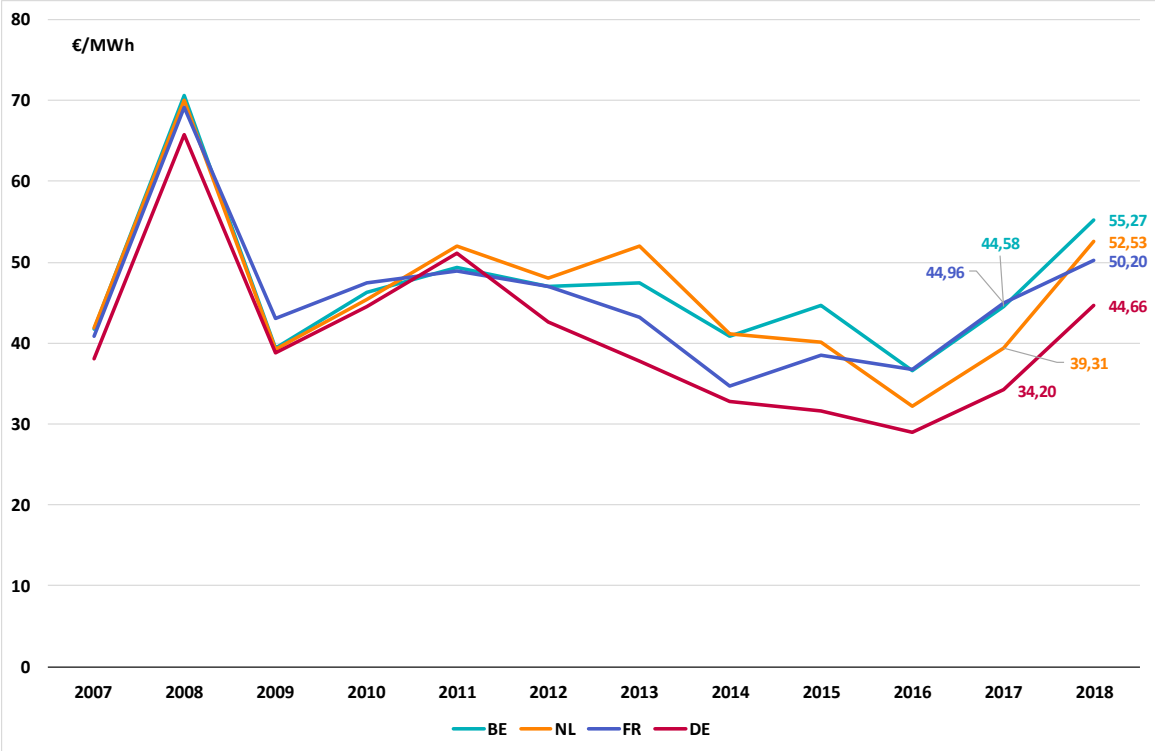

Figure 24: Yearly average hourly day-ahead wholesale electricity prices, per bidding zone in the CWE region, increased in 2018. The Belgian bidding zone together with the Dutch zone have the highest averaged prices. The Austrian bidding zone, separated from the German bidding zone since the first of October, is not presented as no full year of data is available.
Sources: CREG based on data received from EPEX SPOT SE

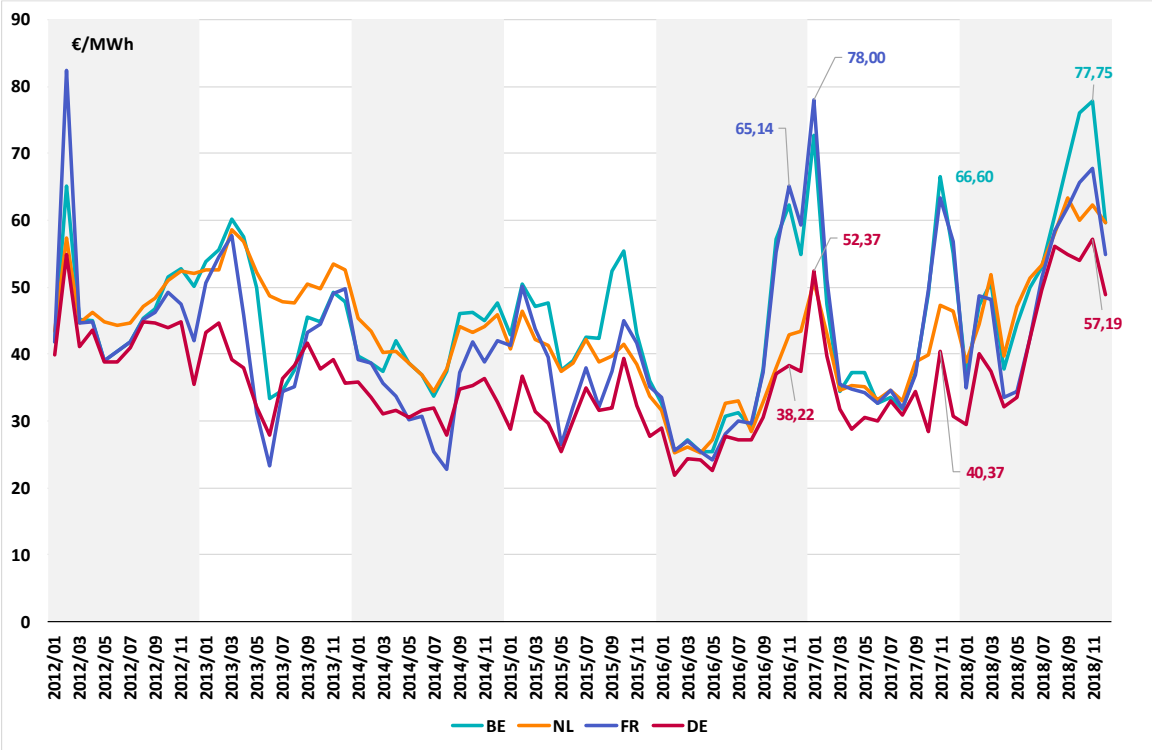

Figure 25 – Evolution of the monthly averaged day-ahead prices in the CWE region.
Source: CREG based on data received from EPEX SPOT

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
<0	0	0	0	0	0	7	15	2	0	2	6	10
[0 - 20[	1493	354	940	457	815	370	830	444	285	989	309	240
[20 - 40[	4190	757	4117	2421	1033	2495	1912	3779	3111	5222	4256	1562
[40 - 60[	1770	2105	2731	4391	4666	4405	3873	4032	4438	1724	2744	3989
[60 - 80[	605	2711	730	1314	2178	1291	1871	477	796	590	913	2140
[80 - 100[	339	1675	199	123	48	140	215	19	65	140	296	584
[100 - 200[	305	1164	43	52	19	73	44	6	29	98	229	215
[200 - 300[	25	13	0	2	0	3	0	1	22	14	5	11
[300 - 500[	15	2	0	0	0	0	0	0	14	2	2	9
[500 - 1000[	14	3	0	0	0	0	0	0	0	3	0	0
[1000 - 3000[	4	0	0	0	1	0	0	0	0	0	0	0

Table 10 – Histogram of the Belgian day-ahead wholesale electricity prices, per year.
Source: CREG based on data provided by EPEX SPOT

41. Defining hours during which the Belgian day-ahead price exceeds 80 EUR/MWh as hours with elevated prices, in 2018 around 9% of the time (819 hours) scarcity was observed, 50% higher than the number of hours of the previous year (Table 10). In 2018, the energy-only market therefore remunerated the most expensive generation asset above its marginal cost, allowing it to receive a premium and therefore mitigating the missing money problem. The price never exceeded €500/MWh in 2018 indicating that no hours with actual scarcity were observed.

A large share of hours (63%) were between 20 EUR/MWh and 60 EUR/MWh in 2018. This share declined with respect to 2017 while the number of day-ahead prices between €60/MWh and €80/MWh increased, indicating that the marginal cost to provide baseload generation capacity increased. The increase in marginal cost is a consequence of the lower available nuclear capacity in 2018.

A negative price was observed during 10 hours in 2018. Negative prices are typically imported from Germany when large volumes of renewable energy are injected into its grid. In 2018, German day-ahead prices were negative for 119 hours on 21 days. The large difference in the number of negative hours between Belgium and Germany suggests that interconnection capacity for day-ahead trade is insufficient to effectively integrate the four markets in the CWE region when infeed from renewable energy is high.

42. Hourly day-ahead prices remain convergent in the CWE-region for 32% of the time (Table 11). Full price divergence in the CWE region has increased to 56%, from less than 6% before 2015. Over the same time span, price convergence between Belgium and France only, Belgium and the Netherlands only, or between Belgium, France and the Netherlands, has decreased from more than 10% to less than 5%. The observations suggest that the introduction of the flow-based market coupling in May 2015 discourages partial market integration in the CWE region if full market integration cannot be achieved.

43. As of the first of October, the Austrian bidding zone split from the German bidding zone. During the fourth quarter of the year, price differences between the German and Austrian bidding zones were smaller than €1/MWh for only 5% of the time. No full price convergence between both bidding zones was observed, indicating more efficient pricing than when price convergence between Germany and Austria was enforced. No conclusions can be drawn on how the split of the German-Austrian bidding zone affected the price convergence within the CWE region, given the high level of nuclear unavailability (and thus increasing probability of price divergence) in the fourth quarter of 2018.

	BE = FR				BE ≠ FR			
	BE = NL		BE ≠ NL		BE = NL		BE ≠ NL	
	BE = DE	BE ≠ DE	BE = DE	BE ≠ DE	BE = DE	BE ≠ DE	BE = DE	BE ≠ DE
2007	0,29%	62,26%	0,11%	26,27%	0,06%	9,45%	0,00%	1,56%
2008	0,11%	69,13%	0,06%	15,21%	0,02%	14,74%	0,00%	0,73%
2009	0,11%	56,69%	0,01%	13,22%	0,06%	28,32%	0,00%	1,59%
2010	8,08%	52,35%	0,07%	26,26%	0,21%	11,79%	0,01%	1,23%
2011	65,82%	5,16%	1,52%	26,69%	0,10%	0,25%	0,00%	0,46%
2012	46,61%	12,85%	11,01%	14,97%	1,90%	11,24%	0,00%	1,42%
2013	14,76%	19,01%	17,28%	20,50%	0,68%	25,05%	0,01%	2,71%
2014	18,66%	10,99%	4,97%	11,89%	5,83%	42,29%	0,00%	5,35%
2015	18,95%	10,16%	0,67%	13,78%	0,27%	14,28%	0,06%	41,83%
2016	34,53%	1,80%	0,42%	7,90%	1,66%	3,72%	0,13%	49,84%
2017	34,19%	3,61%	0,71%	6,31%	1,39%	5,00%	0,14%	48,65%
2018	32,57%	4,43%	1,27%	1,87%	0,00%	3,49%	0,00%	56,37%
JAN	34,41%	8,87%	0,54%	6,18%	0,00%	6,32%	0,00%	43,68%
FEB	30,06%	18,60%	0,00%	2,38%	0,00%	2,83%	0,00%	46,13%
MAR	29,03%	14,78%	0,00%	3,76%	0,00%	6,72%	0,00%	45,70%
APR	37,78%	3,75%	5,00%	0,42%	0,00%	5,14%	0,00%	47,92%
MAY	12,23%	0,00%	5,24%	0,94%	0,00%	6,05%	0,00%	75,54%
JUN	16,39%	0,00%	2,92%	0,00%	0,00%	3,19%	0,00%	77,50%
JUL	63,71%	0,13%	1,48%	0,00%	0,00%	2,02%	0,00%	32,66%
AUG	61,02%	2,55%	0,00%	0,00%	0,00%	0,81%	0,00%	35,62%
SEP	36,53%	0,28%	0,00%	1,94%	0,00%	1,11%	0,00%	60,14%
OCT	20,56%	2,96%	0,00%	4,17%	0,00%	1,61%	0,00%	70,70%
NOV	21,94%	0,14%	0,00%	0,14%	0,00%	1,67%	0,00%	76,11%
DEC	26,34%	2,02%	0,00%	2,42%	0,00%	4,30%	0,00%	64,92%

Table 11 – Full hourly price convergence (≤ 0,01 EUR/MWh) between Belgian day-ahead prices and the day-ahead prices in the other bidding zones in the CWE region, per year and for each month of 2018
Sources: CREG based on data provided by EPEX SPOT

44. Price volatility in 2018 did not change much compared with the situation in 2017 (Figure 26).

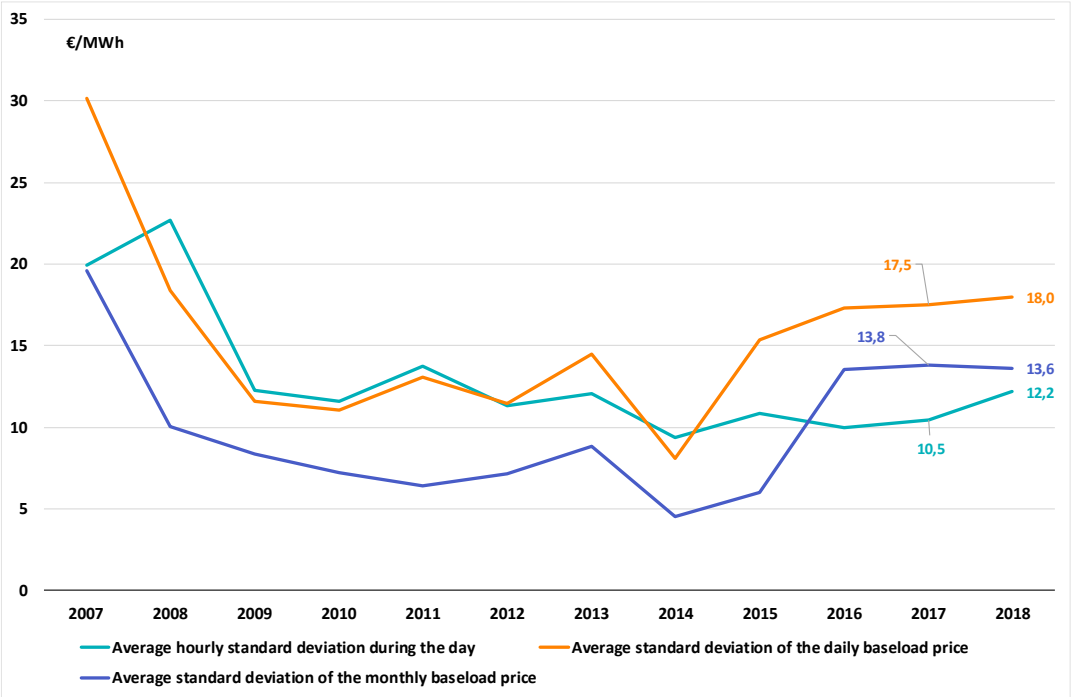

Figure 26 – Volatility of the Belgian day-ahead price, described by three statistics, per year
Source: CREG based on data provided by EPEX SPOT

45. Trade on the Belgian day-ahead market increased by 8.0 TWh in 2018, or 45% compared to 2017 (Table 12). The cause of the increase in trade was increased buyer interest in importing electricity from abroad, probably driven by nuclear unavailability in Belgium. Imports doubled to 15.4 TWh and exports became almost non-existent at 0.2 TWh. Day-ahead trade on the power exchange accounted for more than a third of the Elia load, the highest share since records began. Complemented with the increase in average Belgian day-ahead prices, the value of contracts concluded on the Belgian day-ahead spot exchange increased 80% in 2018 compared to 2017, to 1.5 trillion euro (Figure 27).

Buy volumes increased gradually over the course of the year, achieving peak volumes during the last quarter of the year. Sell volumes remained relatively flat throughout the year indicating that imports are responsible for supplying the increase in buy volumes throughout the year (Figure 28).

The role of the day-ahead power exchange in fairly and objectively creating transparent price signals is important. Day-ahead prices formed on power exchanges determine commercial cross-border exchanges and are used as references for the majority of bilateral contracts. Consequently, the CREG expects market participants to trade, in day-ahead and by efficiently using all products, all available generation and demand capacity at a price that is cost-reflective (i.e. marginal costs). Scarcity on the day-ahead market should be the result of the fair and competitive interplay of demand and supply, not an artificially created opportunity by not offering available generation and demand capacity.

	Buy	Sell	Trade	Import	Export	Net Import	Trade / Load ELIA
2007	6,8	4,8	7,6	2,7	0,8	2,0	8,6
2008	10,4	4,3	11,1	6,8	0,7	6,1	12,6
2009	6,0	9,1	10,1	1,0	4,1	-3,1	12,4
2010	9,6	8,9	11,8	2,9	2,3	0,7	13,7
2011	10,3	9,2	12,4	3,1	2,1	1,1	14,8
2012	15,8	8,9	16,5	7,6	0,6	6,9	20,1
2013	16,1	11,2	17,1	5,9	1,0	4,9	21,3
2014	19,6	9,5	19,8	10,3	0,2	10,1	25,6
2015	23,6	9,6	23,7	14,0	0,0	14,0	30,7
2016	18,3	11,9	19,6	7,6	1,2	6,4	25,3
2017	16,6	10,1	17,9	7,7	1,3	6,4	23,1
2018	25,8	10,6	25,9	15,4	0,2	15,2	33,8
2007-2018	*178,9*	*108,2*	*193,5*	*85,1*	*14,4*	*70,7*	*20,2*

Table 12 – Traded volumes and commercial cross-border exchanges on the Belgian day-ahead power exchange, including the share of traded volume in terms of the Elia load
Source: CREG based on data provided by EPEX SPOT

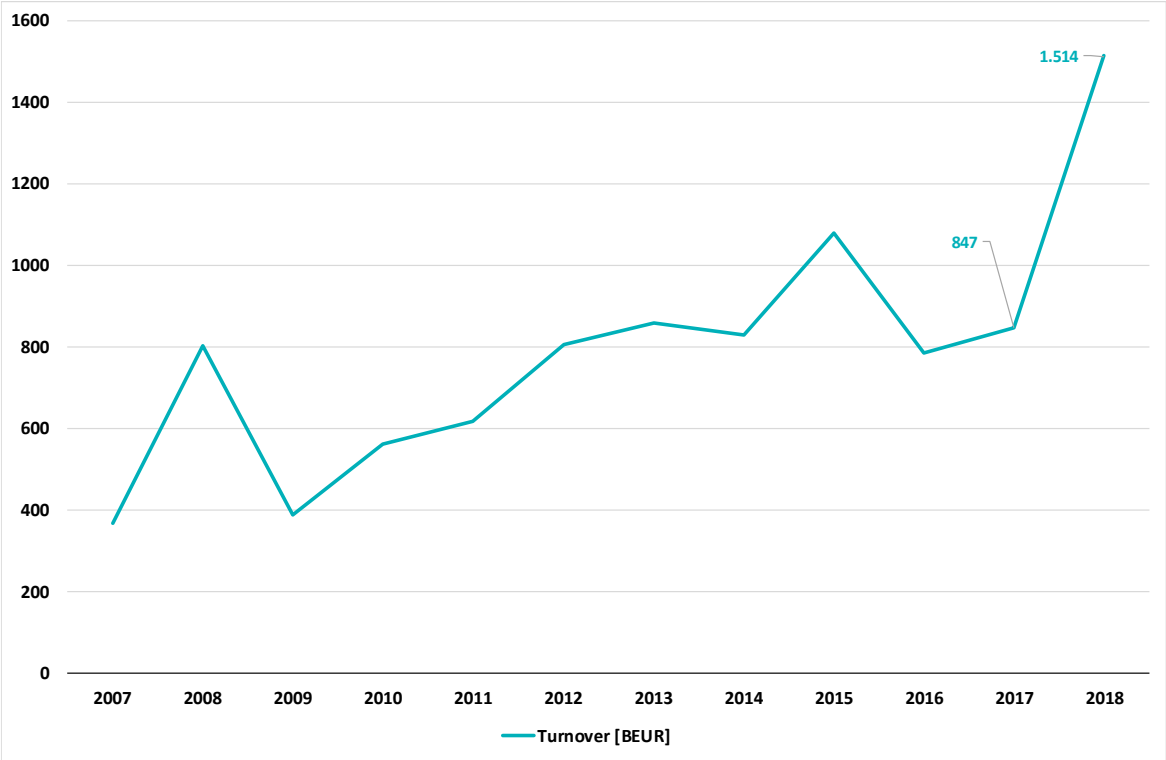

Figure 27 – Value of the contracts traded on EPEX SPOT Belgium
Source: CREG based on data provided by EPEX SPOT

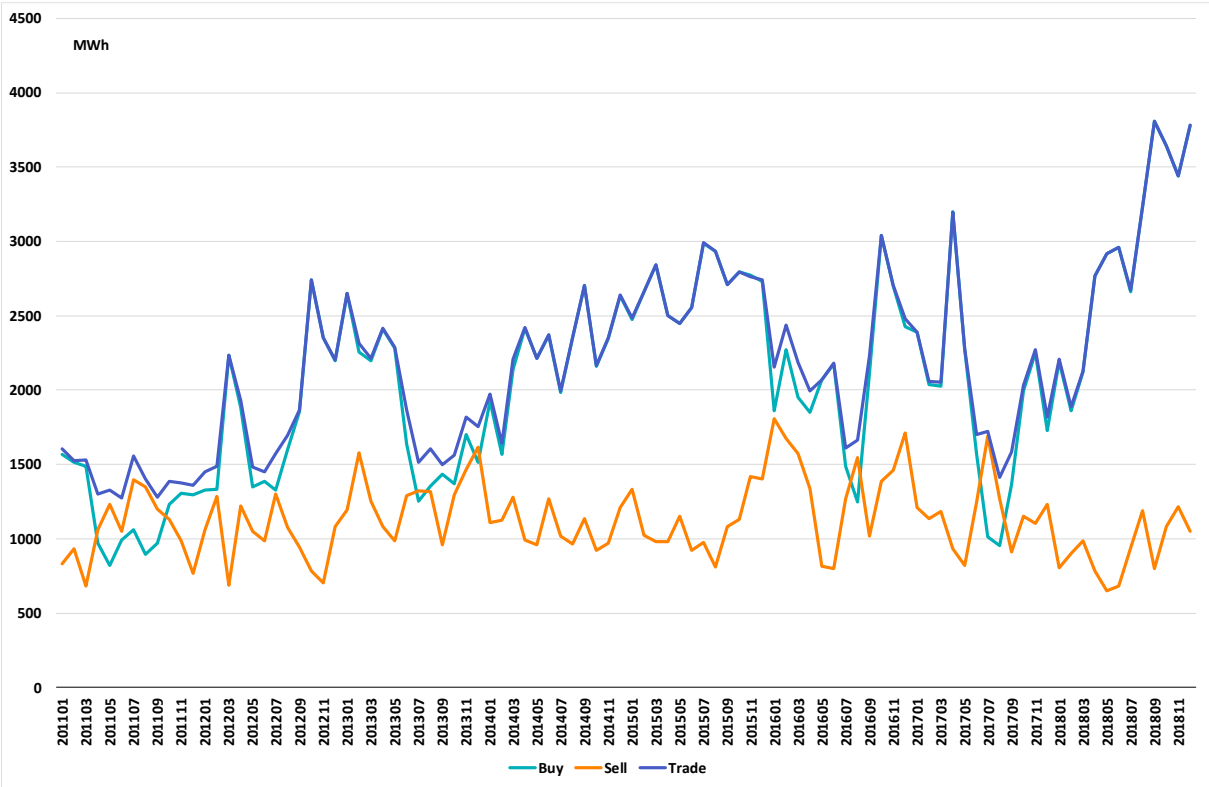

Figure 28 – Average traded, sold and bought volumes on the Belgian power exchange between 2007 and 2018.
Source: CREG based on data provided by EPEX SPOT

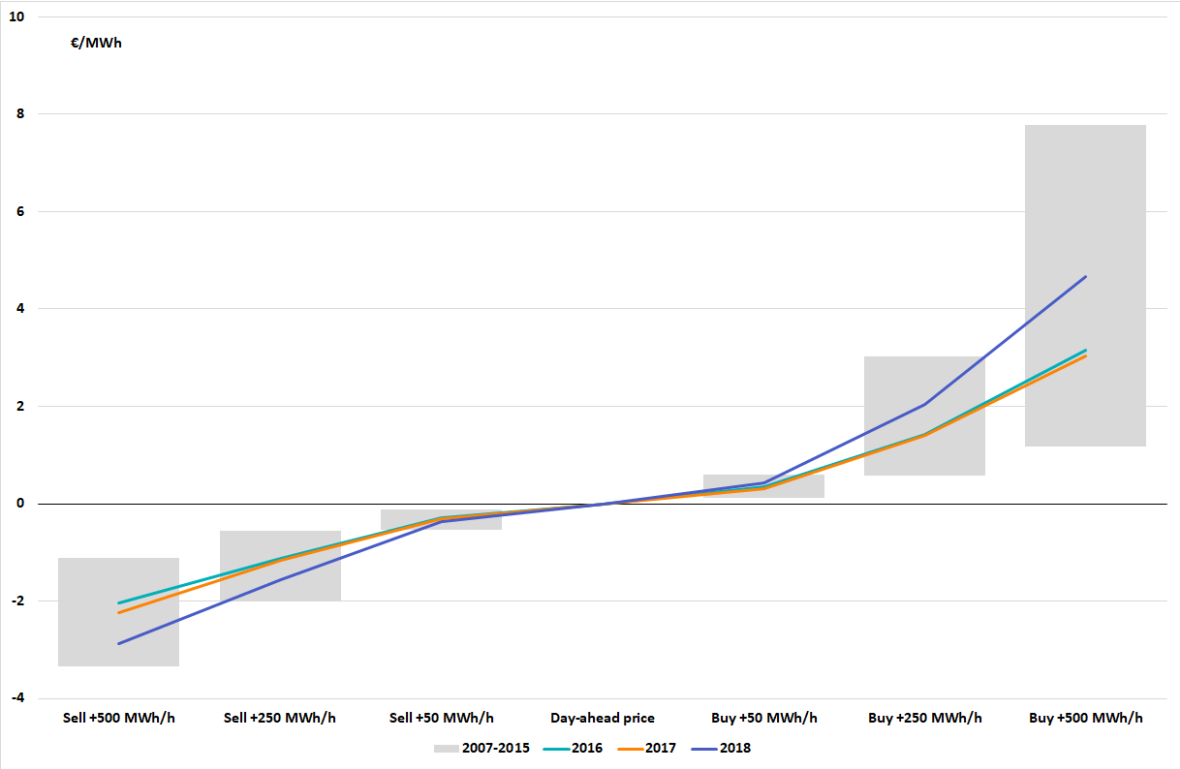

Figure 29 – Average change of the Belgian day-ahead price in terms of additional supply or additional demand, 2007-2018
Source: CREG based on data provided by EPEX SPOT

46. Average day-ahead price robustness in 2018 declined with respect to 2016 and 2017 (Figure 29). Similarly to the previous 2 years, the last quarter of the year showed the highest day-ahead price sensitivity (Figure 30).

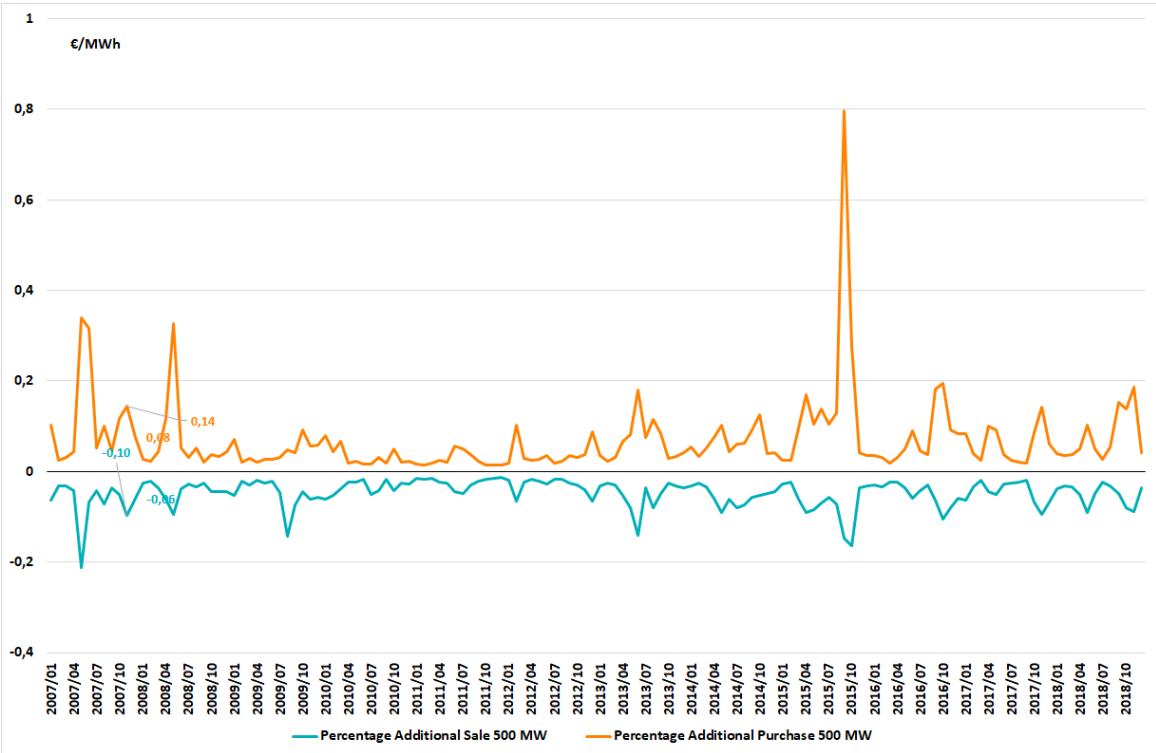

Figure 30 – Average absolute sensitivity of the Belgian day-ahead price in terms of 500 MWh/h additional supply or 500 MWh/h additional demand
Source: CREG based on data provided by EPEX SPOT

3.3.2. Intraday wholesale electricity market for delivery in Belgium

47. In 2018 the traded volume on the intraday power exchange increased slightly compared to the volume traded in 2017 (Table 13). Volumes have increased by 1% since 2017. The yearly traded volume on the intraday market equates to 7.8% of the yearly traded volume on the day-ahead market (see Table 12).

48. In 2018, a volume was traded during 8,401 hours, compared to 8,489 hours in 2017. The average volume traded during these hours increased from 235 MWh/h in 2017 to 240 MWh/h in 2018 suggesting the intraday market becomes sufficiently liquid for market participants to find a counterparty for their trades.

49. Intraday prices were on average 1,02 EUR/MWh higher than day-ahead prices (Table 13). Except for the year 2015, the spread in 2018 is the lowest of the observed period, pointing to a continuously decreasing opportunity cost for exercising the option to trade baseload power on the intraday market instead of the day-ahead market. Correlation between day-ahead and intraday prices nonetheless decreased, from 78% in 2017 to 72% in 2017, indicating a continued reduced statistical relationship.

The hourly spread between the day-ahead and intraday prices is lower than 5 EUR/MWh for 50% of the time (Figure 35). It can be as low as -237.3 EUR/MWh and as high as 554.6 EUR/MWh. The tail of the histogram of the price spread is longer on the positive side.

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Intraday Market Price (EUR/MWh)	84,46	41,78	49,88	55,59	51,66	52,40	42,55	43,96	37,93	45,73	56,29
Day-ahead Market Price (EUR/MWh)	70,61	39,36	46,30	49,37	46,98	47,45	40,79	44,68	36,62	44,58	55,27
Intraday Volume (GWh)	89	187	275	364	513	651	786	737	1089	1991	2012
Import (GWh)	-	-	-	-	-	-	302	239	552	1009	773
Export (GWh)	-	-	-	-	-	-	395	357	403	809	920

Table 13 – Intraday prices and volumes for delivery of electricity in Belgium, 2008-2018. Export and import volumes are provided since 2014.
Source: CREG based on data provided by EPEX SPOT

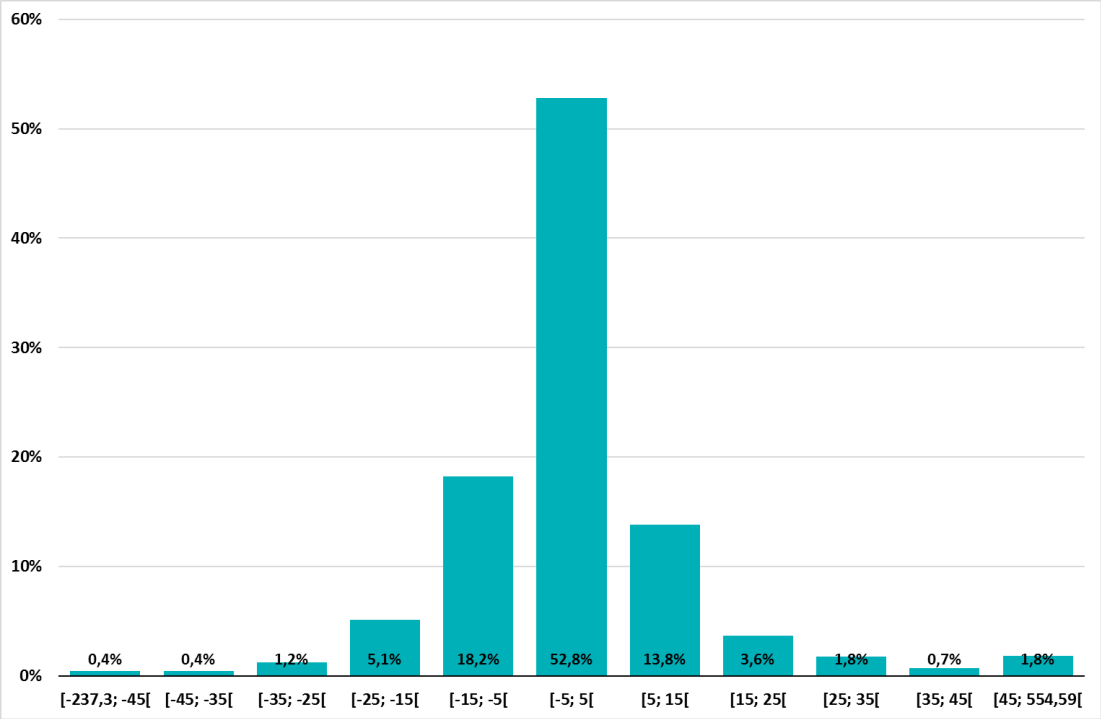

Figure 31 – Histogram of hourly differences between the day-ahead and intraday prices in 2018
Source: CREG based on data provided by EPEX SPOT

3.3.3. Long-term wholesale electricity market for delivery in Belgium

50. The yearly averaged year-ahead wholesale electricity price in Belgium increased to 51.0 €/MWh in 2018 (Figure 32). Year-on-year price increases of 36% were observed in all bidding zones in the CWE region with the exception of France, where the year-on-year increase was 28%. This signals that, on average, market participants expect the average day-ahead price in 2019 to be higher than in 2018 in the CWE region. Year-ahead prices gradually increased throughout 2018 and show a similar profile in each bidding zone. Market participants therefore confidently expect price spreads to remain in the CWE-region during 2018 (Figure 33).

On 26 June 2017 the first long-term contract for delivery in the Austrian bidding zone was traded. As 2018 is the first full year of data, only 2018 data regarding prices for delivery in the Austrian bidding zone is included. The average yearly price is 46.64 €/MWh, or 2.5 €/MWh higher than the average yearly price for delivery in the German bidding zone.

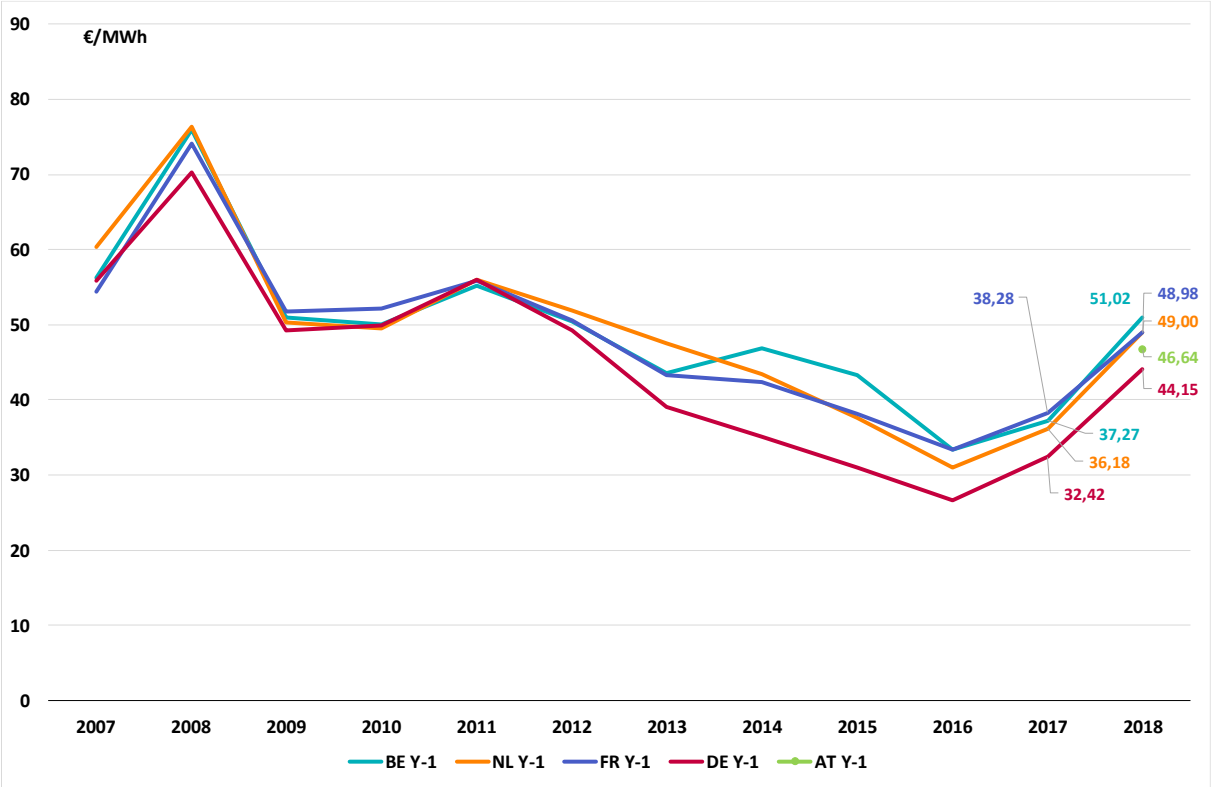

Figure 32 – Yearly averaged year-ahead wholesale electricity prices in the CWE region. Prices for delivery in only the Austrian bidding zone, in contrast to the joint German-Austrian bidding zone, are only shown if a full year of data is available.
Source: CREG based on data provided by ICE Endex and EEX

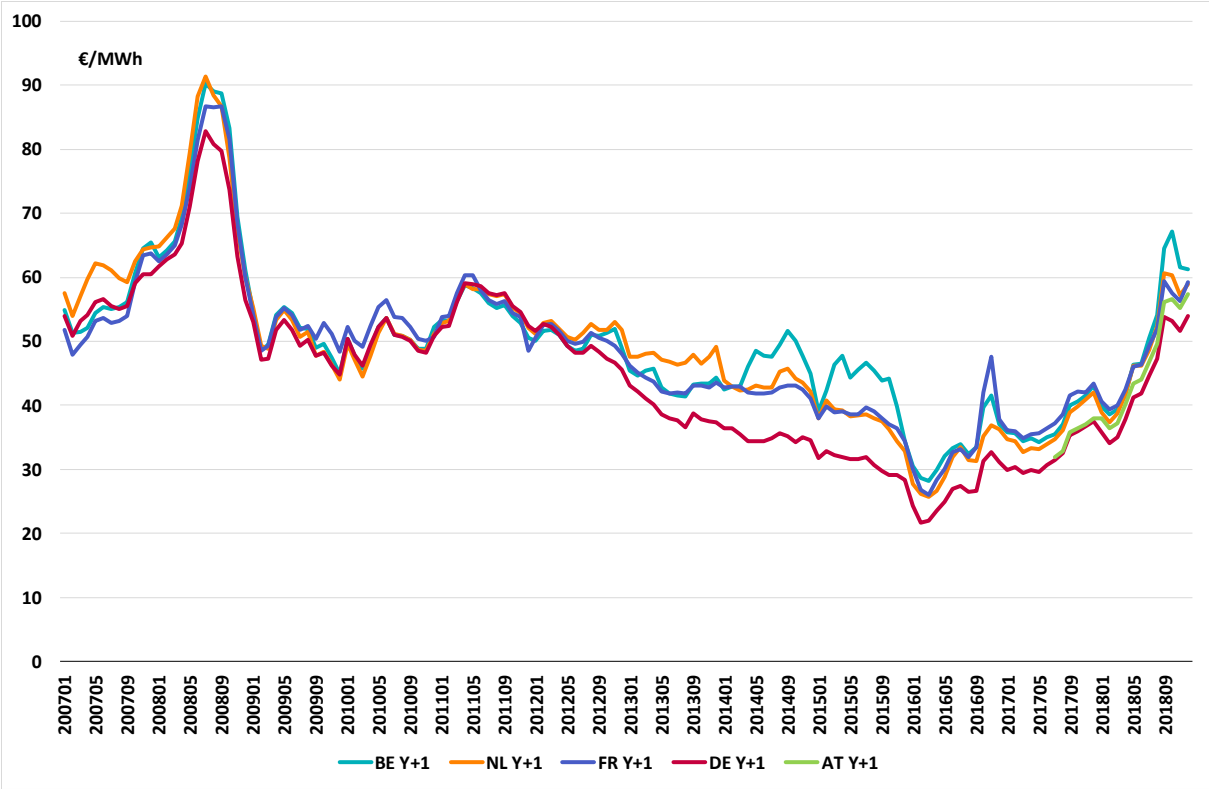

Figure 33 - Monthly averaged year-ahead wholesale electricity prices in the CWE region. Prices for delivery in only the Austrian bidding zone, in contrast to the joint German-Austrian bidding zone, are only shown if a full month of data is available
Source: CREG based on data provided by ICE Endex and EEX

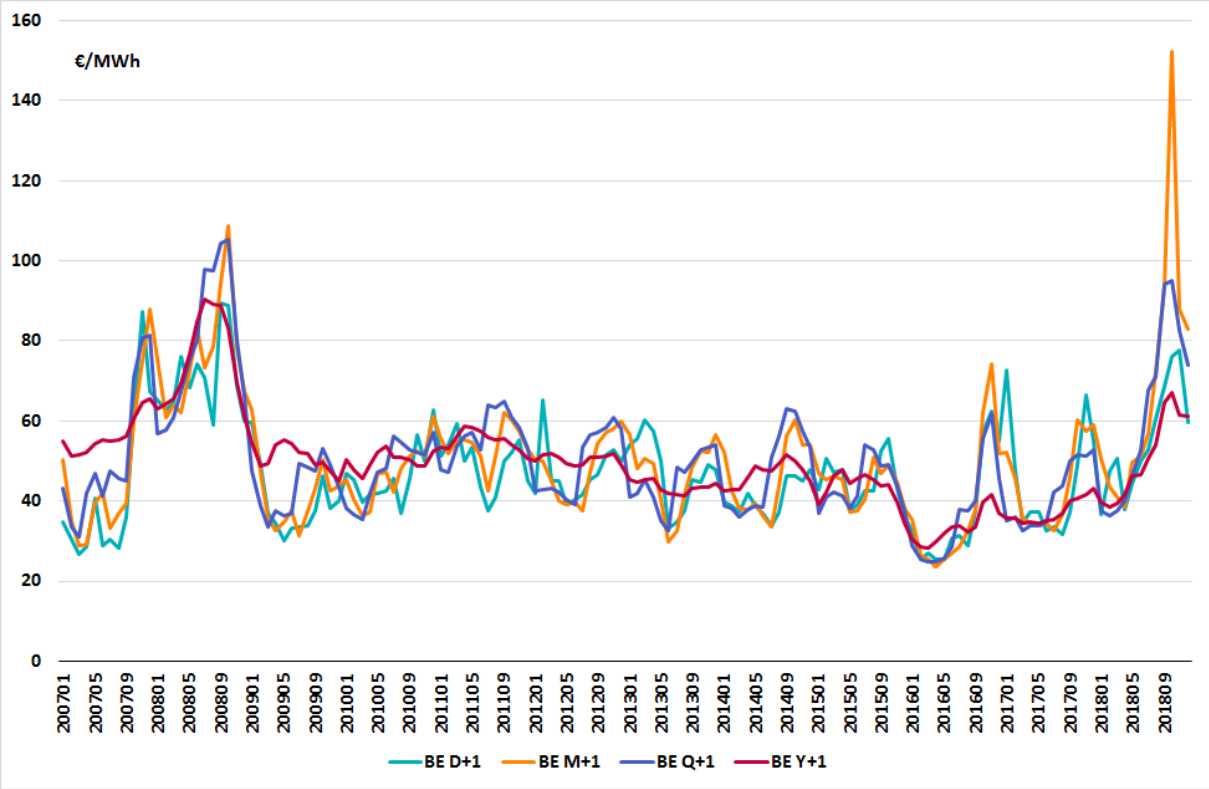

Figure 34 – Monthly average prices for four types of contracts for delivery in the Belgian bidding zone, in terms of month of trade
Sources: CREG based on data provided by EEX and ICE Endex

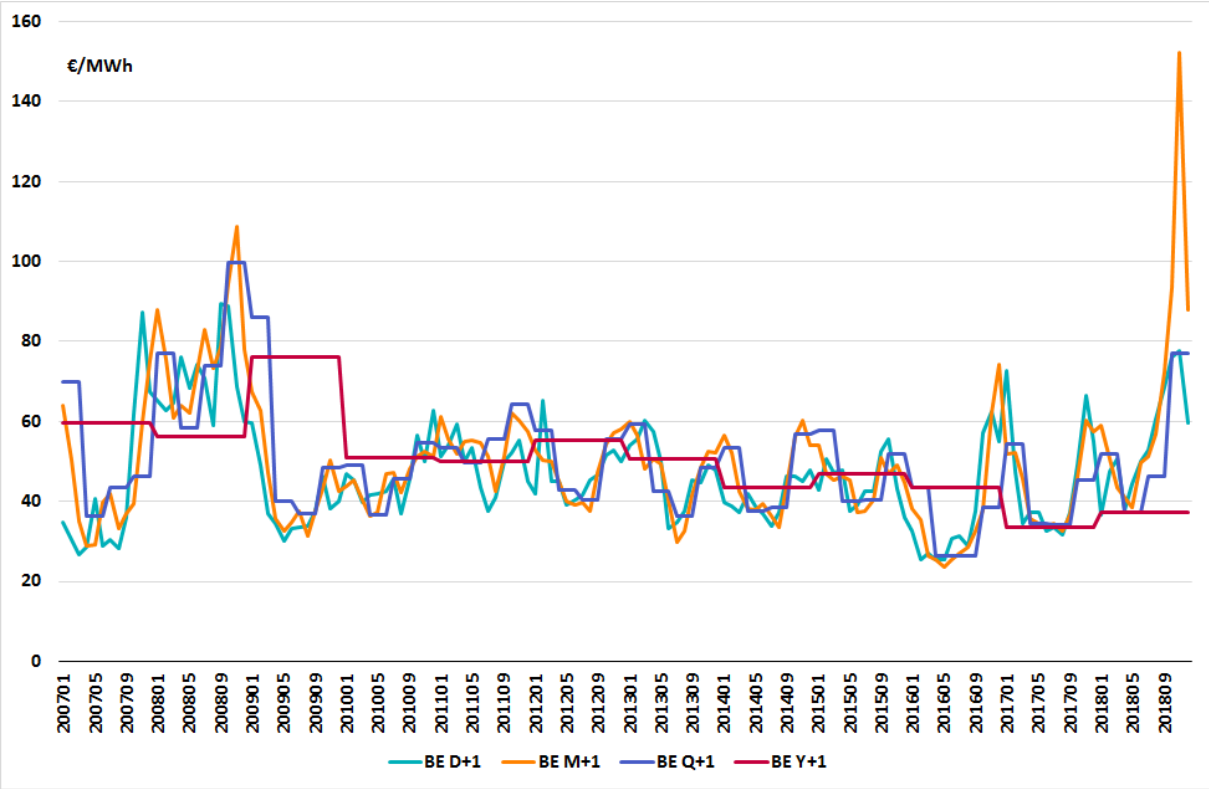

Figure 35 –Average prices for four types of contracts for delivery in the Belgian bidding zone, in terms of delivery period
Sources: CREG based on data provided by EEX and ICE Endex

	BE M+1	BE Q+1	BE Y+1
BE D+1	84,40%	75,96%	63,08%
BE M+1		86,03%	67,24%
BE Q+1			81,56%

	BE M+1	BE Q+1	BE Y+1
BE D+1	54,83%	66,32%	65,78%
BE M+1		84,27%	85,46%
BE Q+1			97,65%

Table 14– Correlation between different types of contracts for delivery in the Belgian bidding zone, for 2007-2018 (left) and for 2018 (right)
Source: CREG based on data provided by EEX and ICE Endex

51. Prices of day-ahead and month-ahead contracts were 55% correlated in 2018, a significant reduction compared with the historical average (Figure 34, Table 14). Quarter-ahead prices were better correlated with day-ahead prices in 2018 but still less correlated compared with the historically good correlation of 73%. Correlation with the year-ahead prices are around 66%, in line with historical records. Year-ahead prices are very well correlated with quarter-ahead prices (98%) and month-ahead prices (84%).

In contrast to the years before 2017, year-ahead contracts were again the least expensive to source a baseload supply from in 2018 (Figure 35). On the other hand, month-ahead contracts were the most expensive. Sourcing using year-ahead contracts resulted in a discount of 18.0 EUR/MWh compared with sourcing using the day-ahead market (Y+1 2017 versus D+1 2018, Table 15). Historically however, contracts traded with a longer lead time before delivery on average trade at a premium with respect to shorter term contracts.

	D+1	M+1	Q+1	Y+1	Δ (D+1, M+1)	Δ (D+1, Q+1)	Δ (D+1, Y+1)
2007	41,78	46,15	50,65	56,28	4,37	8,87	14,50
2008	70,61	77,01	79,84	76,02	6,40	9,23	5,41
2009	39,36	41,62	43,77	50,98	2,26	4,41	11,62
2010	46,30	46,69	47,75	50,03	0,39	1,45	3,73
2011	49,37	54,25	56,80	55,18	4,88	7,43	5,81
2012	46,98	48,15	49,62	50,49	1,17	2,64	3,51
2013	47,45	46,58	45,41	43,57	-0,87	-2,04	-3,88
2014	40,79	45,74	47,82	46,90	4,95	7,03	6,11
2015	44,68	43,98	44,04	43,32	-0,70	-0,64	-1,36
2016	36,62	37,54	36,44	33,38	0,92	-0,18	-3,23
2017	44,58	43,92	41,43	37,27	-0,67	-3,15	-7,32
2018	55,27	68,85	61,37	51,02	13,58	6,10	-4,25

Table 15 – Average prices for four types of contracts for delivery in Belgium, per year of delivery, 2007-2018
Source: CREG based on data provided by EEX and ICE Endex

4. INTERCONNECTIONS

4.1. HISTORICAL BACKGROUND : SIGNIFICANT EVENTS

2001 ETSO (the predecessor to ENTSO-E, *i.e.* the member organization of all European transmission system operators) publishes its guidelines regarding methodologies for the calculation of available transmission capacities (ATC) for cross-border interconnections. In 2016, these methodologies are still being applied by some Transmission System Operators, among which Elia, for the calculation of available interconnection capacities.

2005 The Belgian, Dutch, French, Luxembourg and German governments found the Pentalateral Energy Forum (PLEF). This Forum is established to optimize and harmonize the methodologies applied for the calculation and allocation of cross-border interconnection capacities between the different countries involved, among other things. The PLEF consists of representatives of Ministries, National Regulatory Authorities, Transmission System Operators, Power Exchanges and the Market Parties Platform.

2007 In **February**, CWE regulators publish their action plan to strengthen the integration of their power markets. This action plan anticipates the development and implementation of a *flow-based* market coupling for the CWE bidding zones. In **June**, all Ministers of the CWE countries sign, jointly with the representatives of TSOs, power exchanges, regulators and market participants, a Memorandum of Understanding to develop and implement the flow-based market coupling for the day-ahead timeframe.

2008 In **June**, CWE TSOs and power exchanges, through the Joint Steering Committee, unilaterally announce the implementation of an ATC-based approach to couple the markets in the CWE region.

2010 Elia develops and submits a proposal for a new general model for the calculation of the total transfer capacity and the transmission reliability margin. In addition, Elia submits a proposal for the calculation of day-ahead transmission capacity to the CREG, for approval. In **October**, the CREG decides not to approve the proposal from Elia, due to the fact that it considers the proposal to be in breach of European legislation on the non-discrimination of domestic and cross-zonal exchanges. In light of other benefits of increased market coupling in the CWE region, the CREG decides nonetheless to authorise the implementation of the proposed methodology.

2011 Elia develops and submits a proposal for the calculation for yearly and monthly transmission capacities as well as the transmission reliability margin. The CREG once again decides not to approve, based on the same argumentation as above, but takes note of the implementation by Elia of the proposed methodology. Elia appeals the CREG's decision but, in **2012**, the Court of Appeal rules that Elia's arguments for the appeal are unfounded.

2013 The CWE Flow-Based Market Coupling project starts the first "external parallel run", in order to compare the simulated flow-based market results with the ATC calculations on a weekly basis. In **August**, the CWE FBMC Project develops the first FBMC "approval package", containing a description of the flow-based market coupling methodology. This document forms the basis for the first submission of a proposal by Elia for a day-ahead flow-based market coupling methodology.

2014 The CWE FBMC Project starts running daily "internal parallel runs", starting from **February**. In **May**, the CWE FBMC Project submits a second approval package[14]. CWE regulators consider the package to be incomplete and continue the development and discussions with the CWE FBMC Project partners. In **June**, CWE regulators organize a public consultation on the FBMC. In **August**, the CWE FBMC Project submits a third, adapted version of the approval package[15]. Between then and **March 2015**, the partners continue modifying and adding to the approval package, in cooperation with CWE regulators. Over the following months, project partners address issues related to the functioning of FBMC in times of scarcity and flow factor competition.

2015 In **February**, Elia submits for approval the methodology for day-ahead flow-based market coupling of the CWE markets, to the CREG. In **March,** they publish their views on FBMC in a position paper[16]. In **April**, the CREG rules that the proposal is in breach of Regulation 714/2009, specifically the articles related to non-discrimination of internal versus external exchanges[17]. However, in light of the expected benefits of ongoing market coupling implementation - in particular the social welfare gain compared to ATC expected by the results of the parallel runs – the CREG decides to approve the proposal conditionally on the implementation of a number of improvement proposals, by the CREG and other CWE regulators. In **May**, the CWE FBMC Project operates the first successful business day of day-ahead flow-based market coupling. In **August,** Regulation (EU) 2015/1222 ("CACM Guidelines") enters into force, providing a legal framework for regulators, TSOs and power exchanges ("NEMOs") to develop common methodologies for all aspects related to single day-ahead and intraday market coupling of European bidding zones. For long-term (yearly and monthly) market coupling, the CREG approves, in **October**, the early implementation of the Harmonized Auction Rules and, for the Belgium-Netherlands and Belgium-France borders, the introduction of "Financial Transmission Rights – options". This replaces the earlier approach where "Physical Transmission Rights with Use-it-or-sell-it" were used.

2016 Regional (voluntary) cooperation shifts towards a more closely integrated, European approach for coupling markets. With the introduction of the CACM Guideline in 2015, the single day-ahead and intraday coupling officially become the pillars of the *"Target Model"* for the design of European electricity Markets. Regulation (EU) 2016/1719 establishing a guideline on forward capacity allocation (the "FCA Guideline") does the same for forward market coupling. With the introduction of the CACM Guideline in 2015 and the FCA Guideline in 2016, the market coupling of the Belgian bidding zone and other bidding zones can be discussed on a geographical basis (i.e. regional versus European) or on a temporal basis (i.e. long-term markets versus short-term markets). On 17 **November** 2016, ACER issued its Decision 06-2016 on Capacity Calculation Regions[18]. With this decision, taken after all regulatory authorities failed to agree on the all TSOs proposal pursuant to art. 9(6)(b) of the CACM Guideline, ACER confirmed that the future regional aspects of both the CACM as well as the FCA Guidelines should be the CORE CCR[19], rather than two separate CWE and CEE regions. The most important consequence of ACER's Decision 06-2016 concerns the regional scope of capacity calculation methodologies and related proposals. Starting from the moment of this decision, TSOs and

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[14] http://www.elia.be/~/media/files/Elia/Projects/CWE-Flow_Based/CWE_FBMC_approval-document_06-2014.pdf.

[15] http://www.jao.eu/support/resourcecenter/overview?parameters=%7B%22IsCWEFBMC%22%3A%22True%22%7D.

[16] http://www.creg.info/pdf/Opinions/2015/b1410/CWE_NRA_Position_Paper.pdf.

[17] http://www.creg.be/nl/publicaties/beslissing-b150423-cdc-1410.

[18] http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2006-2016%20on%20CCR.pdf .

[19] The Core Capacity Calculation Region consists of the borders between France, Belgium, the Netherlands, Germany, Luxemburg, Austria, Czeckia, Slovakia, Hungary, Poland and Romania. https://www.entsoe.eu/major-projects/network-code-implementation/cacm/core-ccr/Pages/default.aspx .

NEMOs of the CORE CCR need to start developing a flow-based market coupling methodology for the day-ahead and intraday timeframes, to be submitted for approval in Q3 2017. In **November**, ACER published its Recommendation 02/2016 on the Common Capacity Calculation and Redispatching and Countertrading cost sharing methodologies[20], recalling the objectives of the CACM Regulation to establish a well-functioning internal electricity market through the effective implementation of efficient, transparent and non-discriminatory common methodologies. The results of the first one and a half years of CWE FBMC are well below expectations. In 2016, CWE cross-zonal exchanges are 3,700 MW on average during congested hours, a decrease of 900 MW compared to the average of 4,600 MW obtained with ATC in 2014. Internal lines in the Amprion region appear to be the most constraining elements in the CWE FBMC. In **December**, under regional pressure, Amprion applies winter ratings on these lines, increasing the capacity by 20% compared to summer values.

2017 The persistent underperforming results of the day-ahead market coupling with CWE FBMC prompts action on the part of the NRA. In **March** 2017, the CREG proposes a revised CBCO-selection method to address the problem of discrimination of domestic versus cross-zonal trade being at the basis of the low cross-zonal available capacity in the CWE FBMC. In **December** 2017, the CREG publishes Study 1687 on the impact of TSO discretionary actions on the functioning and design of the CWE FBMC[21]. In **December** 2017, CWE regulators agree upon a set of short-term and medium-term solutions to remedy the situation of low cross-zonal capacities in the CWE region. This agreement lies at the basis of the 20% minimum RAM threshold applied on 26 April 2018 as a short-term solution, and the CNEC-selection study to be submitted by CWE TSOs on 1 May 2018 towards a medium-term solution.

In **June** 2017, CWE TSOs submit a common proposal for the capacity calculation for the intraday timeframe with planned go-live date in October 2018. In **September**, CWE NRAs compose a common position paper with requests for clarifications and improvements of the proposed methodology[22]. In **November** CWE TSOs communicate delays for the start of the external parallel runs and the go-live of the new methodology.

Following the entry into force of the CACM Guidelines and ACER's Decision 06-2016 to establish the Core capacity calculation regions, TSOs of the Core CCR started to develop the methodologies for regional capacity calculation and congestion management. In **September** 2017, the Core TSOs developed and submitted a proposal for the coordinated capacity calculation methodology, for the approval of all Core regulatory authorities. The aim of this methodology is to develop and establish flow-based capacity calculation methodologies for the day-ahead and intraday timeframes.

Status update 2018

The CWE NRA agreement to apply a 20% minimum RAM threshold on CNECs is implemented as of business day 26 **April** 2018. The implementation of this short-term measure is considered as a first important step to structurally improve CWE FBMC performance. With a few exceptions, this minimum RAM threshold is respected in all hours. One part of the exceptions were communicated as being due to manual input errors, given that the processes and tools used to implement this 20% minimum RAM threshold had not yet been fully tested and industrialized. CWE TSOs communicate that such errors

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[20] https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2002-2016.pdf

[21] http://www.creg.be/nl/publicaties/studie-f1687

[22] See annex of CREG Decision 1732 of 22 February 2018 on the methodology for calculating cross-zonal capacities in the intraday time frame : http://www.creg.be/nl/publicaties/beslissing-b1732

will no longer occur once the fully industrialized solution, expected 1 October 2018, is implemented. Another part of the exceptions were communicated as being due to system security issues. Market parties ask for improved transparency and monitoring of these so-called "minRAM derogations". In **December** 2018, CWE NRAs propose a template for extensive monitoring of those cases.

In parallel to the application of the 20% minimum RAM threshold, CWE TSOs prepare a CNEC selection study following the CWE NRA agreement of December 2017. Based on this study, submitted in **May** 2018, CWE TSOs conclude to only have the 20% minRAM implemented and to keep the 5% PTDF-threshold as a single CNEC selection criterium. Given the lack of evidence to back up this conclusion, the study is not published and not approved by CWE NRAs.

In **June** 2018, CWE TSOs submit an updated CWE FBMC approval package related to the introduction of the German/Luxembourg-Austrian (DE/LU-AT) bidding zone border on 1 October 2018 and the implementation of the 20% minimum RAM threshold. In **August** 2018 and in addition to the conditions of the CWE NRA common position paper of 2015, CWE NRAs formulate a common position on this updated approval package and agree on additional conditions to be fulfilled by CWE TSOs. This includes improvement of the monitoring on minRAM derogations and compliance with transparency obligations. In its decision of **September** 2018, the CREG approves the updates made to the original CWE FBMC approval package but does not approve it in its entirety since the conditions for approval of the CWE FBMC approval package in 2015 have not yet been fulfilled. In the same light, CWE NRAs agree on the organization of a high-level meeting to be held in early 2019 to ensure progress on the fulfilment of conditions of this 2015 CWE NRA common position paper.

In **June** 2018, CORE TSOs submit the amended version of the CORE capacity calculation methodology for the day-ahead and intraday timeframe. With this methodology, the markets of both the CWE and the CEE region will be coupled with FBMC. CWE NRAs do not reach an agreement on whether to approve the methodology or not. In **August** 2018, CWE NRAs refer the methodology to ACER. ACER starts the discussion with CWE NRAs and CWE TSOs and launches a public consultation of its draft decision in **December** 2018.

4.2. SPECIAL TOPICS: IMPACT OF SIGNIFICANT EVENTS AND STRUCTURAL IMPROVEMENTS OF CWE FBMC IN 2018

The day-ahead CWE FBMC underwent significant events and structural improvements in 2018. In this special topic, different market coupling performance indicators are analysed to understand if and to what extend these changes have affected or improved the market coupling results, notably:

1) **The implementation of the 20% minRAM threshold on 28 April 2018.** This measure is expected to improve overall CWE FBMC performance. Specifically, this measure is expected to decrease the number of active internal CNECs with low PTDF and very low RAM which heavily constrained the market coupling since the start of CWE FBMC in May 2015. Since these active internal CNECs with very low RAM were associated with low cross-border exchanges and very high shadow prices, the minimum RAM threshold is expected to increase cross-zonal exchanges and decrease shadow prices. It is shown that the congestion shifts from internal CNECs with low PTDF and low RAM to internal and cross-zonal CNECs with higher PTDF- and RAM-values. This is an obvious consequence of the fact that the number of limiting internal CNECs is reduced, leading to higher power exchanges between bidding zones and hence higher loading of cross-zonal CNECs.

2) **The inclusion of the DE/LU-AT bidding zone border on 1 October 2018.** This measure is expected to improve overall CWE FBMC performance. The decision to split the large former

DE/LU/AT bidding zone into two separate bidding zones is expected to reduce redispatching needs in the German bidding zone and provide more cross-zonal capacity in the CWE and CEE capacity calculation regions. The increase of available cross-zonal capacity should arise from three aspects, i.e. firstly, a decrease of the preloading of CNECs in the basecase giving rise to higher RAM values, secondly, a decrease in loop flows generated by the DE/LU bidding zone compared to the DE/LU/AT bidding zone and, thirdly, the Austrian bidding zone net position as extra optimization variable in the FBMC social welfare optimization. The increase of available cross-zonal capacity allows for higher power exchanges between the bidding zones.

3) **The removal of the DE/LU/AT and FR external constraints on 1 October 2018.** This measure is expected to increase the maximum volume of feasible CWE cross-zonal exchanges. The DE/LU/AT export limit having constrained the market was 477 hours in 2017, and it is expected that the removal of this export limit will have a significant impact on the average and maximum CWE cross-zonal exchanges, further improve price convergence and contribute to increased security of supply during scarcity conditions.

4) **The increase of the BE import constraint from 4,500 MW to 5,500 MW on 1 July 2018.** This measure is expected to increase the maximum import capacity for Belgium, at least in combination with the aforementioned changes (minimum RAM threshold, introduction of the DE/LU-AT bidding zone border and removal of DE/AT/LU and FR export limits). Since the start of CWE FBMC in 2015, the Belgian import constraint of 4,500 MW had never been limiting because the flow based domain in the market-likely corners was been constrained by other much more limiting network constraints. With the aforementioned changes, however, it is expected that the flow based domain is increased and that the former import limit of 4,500 MW can be exceeded when Belgium is willing to pay high prices.

5) **The unplanned outages of several Belgian nuclear reactors in winter period (October 2018 – February 2019).** From October to December, these power plant outages represented a decrease of the total Belgian generation capacity of roughly 1,500 MW to 2,500 MW compared to the same period in 2017, triggering scarcity situation alerts and the implementation of several adequacy measures[23]. A major unknown in the adequacy equation was the available Belgian import capacity from the CWE region. It has been shown that, thanks to the improvements in CWE FBMC, Belgium was able to import much more than what was formerly the case and that the adequacy patch was never triggered.

6) **The unplanned outage of one Phase Shift Transformer (PST) in Van Eyck from 21 September 2018 to 14 December 2018.** The same moment that Belgium faced adequacy risks due to the simultaneous outages of several nuclear power plants units, one of the PSTs in Van Eyck at the Belgian northern border failed. This PST outage was expected to decrease the Belgian import capacity since PSTs are used to push back loop flows which reduce the commercial capacity at the Belgian borders. The loss of one PST means that the amount of loop flows which can be pushed back decreases, at least if the operational procedures concerning the use of the PST tap positions are maintained.

The analysis shows that the performance of CWE FBMC improved in 2018, starting with the implementation of the 20% minRAM threshold at the end of April and with the further improvements related to the increase of the Belgian import limit, the removal of the DE/AT/LU and FR export limit and the introduction of the DE/LU-AT bidding zone border. Combined with the tight conditions on the

[23] For an elaborated study on the impact of the unavailability of Belgian nuclear power plants on the electricity wholesale market, see CREG study (F)1950 published on 20 June 2019 (available in French and Dutch).

Belgian market from October 2018 on, these improvements made it possible to observe record values for Belgian imports. With respect to the location of congestion, one observes a shift from congestion on internal lines with low PTDF and very low RAM towards internal lines and cross-zonal lines with higher PTDF and higher RAM. This shift is associated with a reduction of the shadow prices.

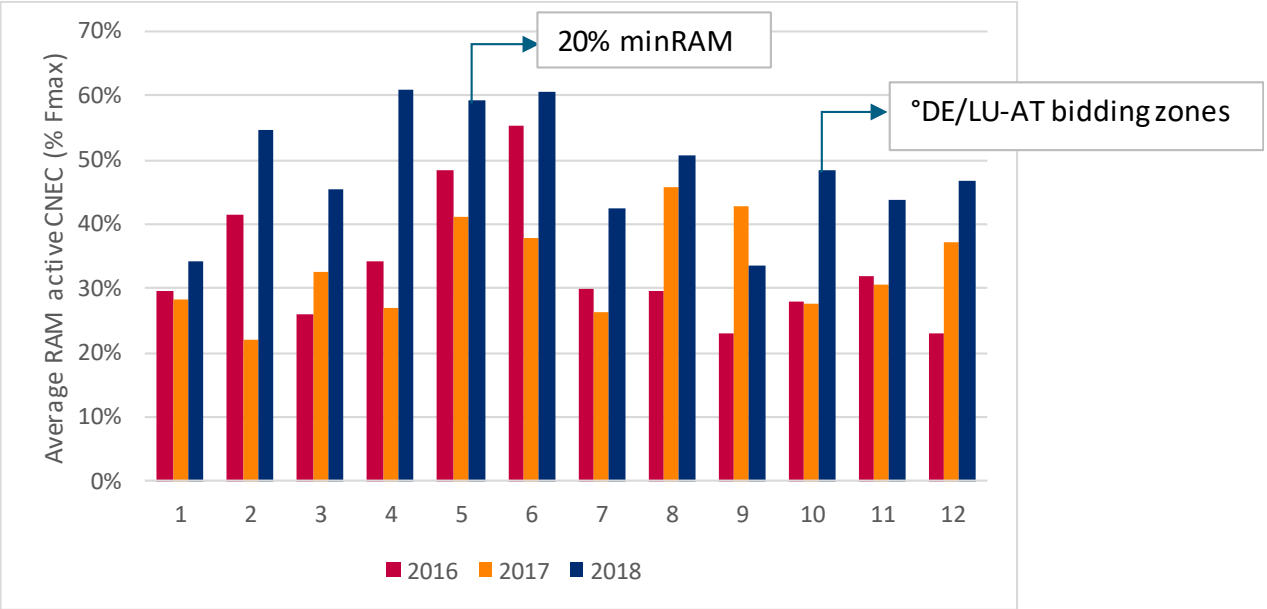


Figure 36: For all months of 2018 except for September, the average RAM on the active CNEC, expressed as a percentage of the thermal capacity (% Fmax), exceeded the averages obtained in 2016 and 2017.

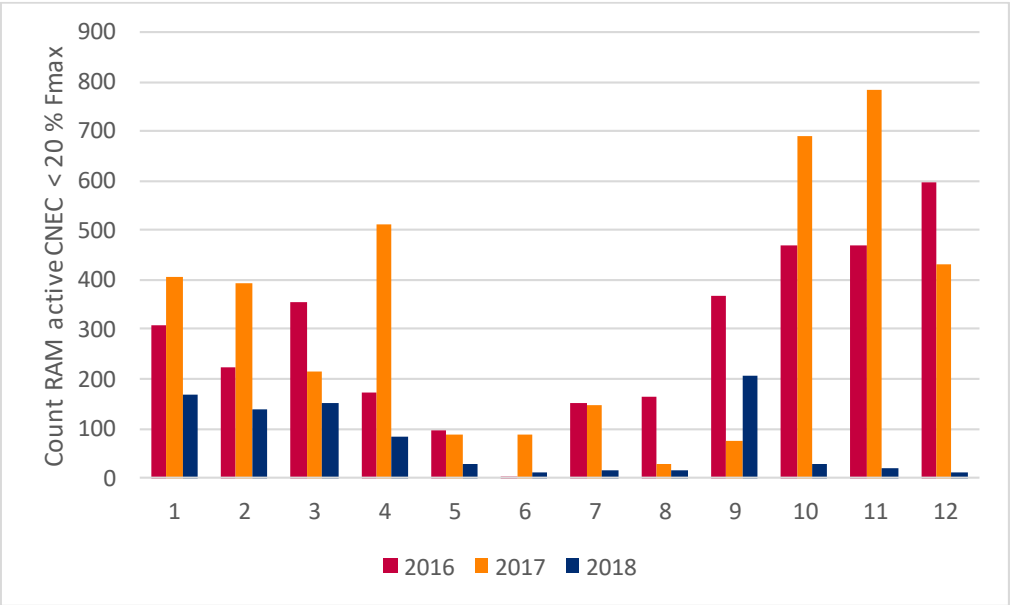


Figure 37: For all months of 2018 except for September, the frequency of active CNECs with less than 20% RAM was lower compared to 2016 and 2017. Despite the 20% minimum RAM threshold only being formally implemented from end of April 2018 on, the RAM-values on internal CNECs already increased earlier thanks to the implementation of winter limits and DLR on highly impacting CNECs by Amprion. The impact of the 20% minRAM implementation is most notable in the months October to December when the number of active CNECs with RAM values inferior to 20% Fmax were highest. In the summer months the improvement is less pronounced.

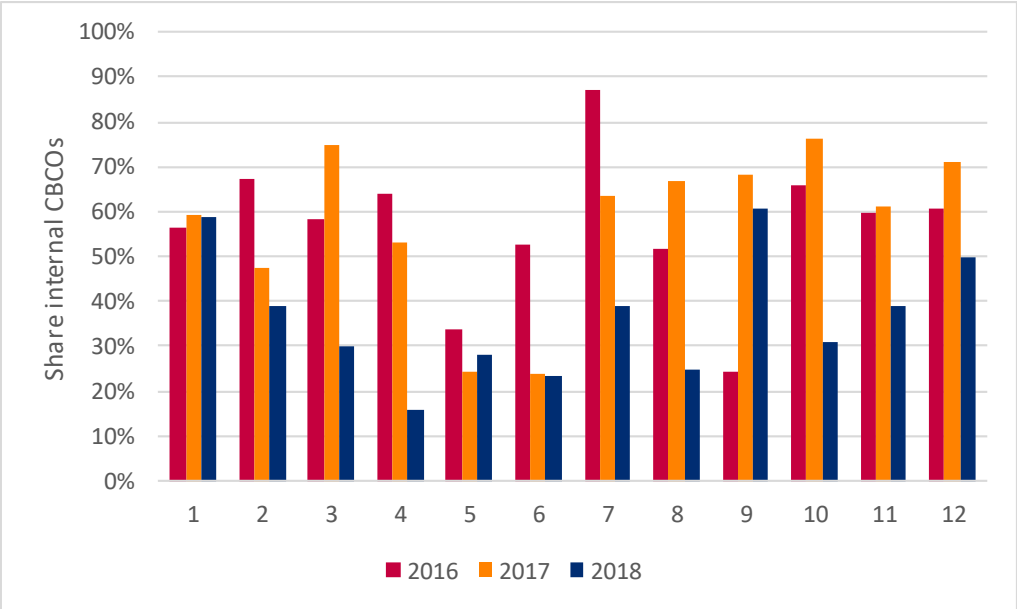


Figure 38: For all months of 2018, except for September, the share of active internal CNECs decreased, implying that the congestion shifts from internal to cross-zonal network elements. Nevertheless, the share of active internal CNECs after the introduction of the 20% minRAM threshold and the introduction of the DE/LU-AT bidding zone border remains very high with monthly shares ranging from 20% to 50%.

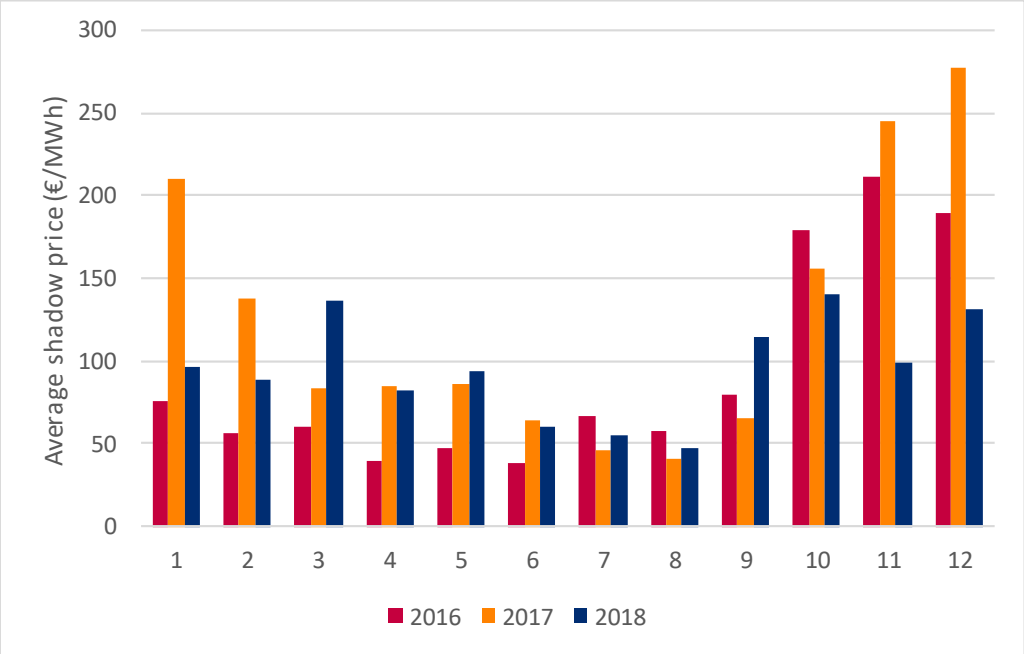


Figure 39: During the summer months, the monthly average shadow price of congestion in 2018 remains similar to the previous years. However, during the winter months, a clear reduction of the average shadow price can be observed. Since shadow costs depend on both market conditions and available network capacity, this evolution may be explained by less tight market conditions in France in 2018 compared to 2016 and 2017 and to the increase of the available cross-zonal capacity.

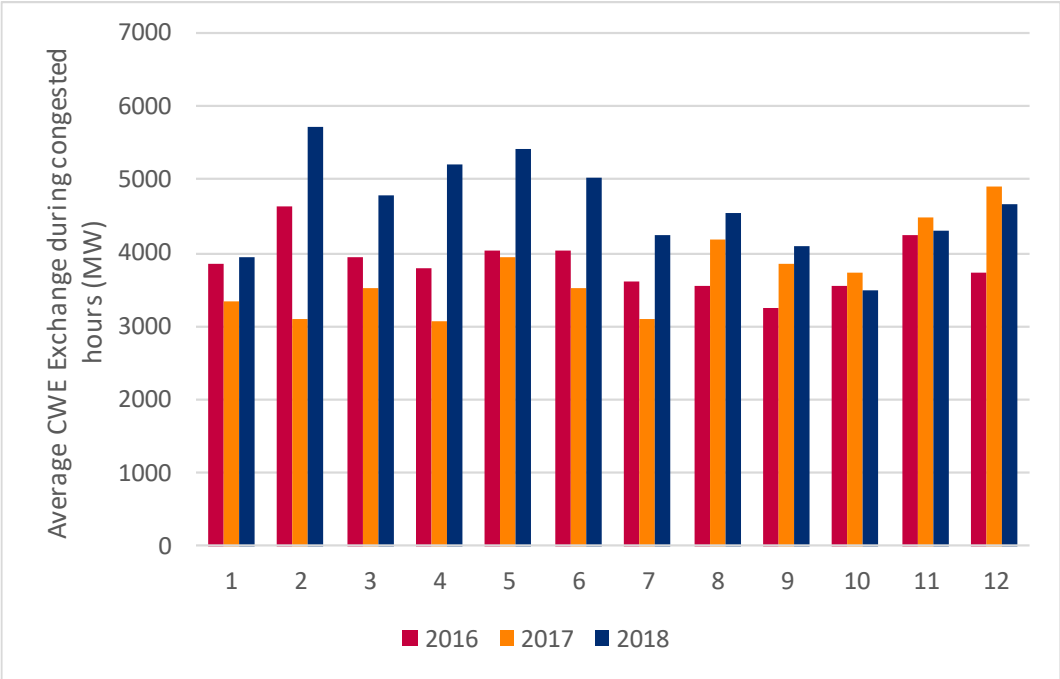


Figure 40: From January to September, the average volume of cross-zonal exchanges in the CWE region during congested hours in 2018 was higher than in 2016 and 2017, especially the first half of the year. However, from October to December, the average exchanges were similar and even lower than in previous years. This may be explained by the fact that in winter 2016-2017 and 2017-2018, France was heavily reliant on imports, while in winter 2018-2019 this was the case for Belgium. Imports to France from the CWE region typically make less extensive use of the network capacity on a singular CNEC (lower PTDF) than imports to Belgium. With similar available network capacity, France will hence be able to import more from the CWE region than Belgium.

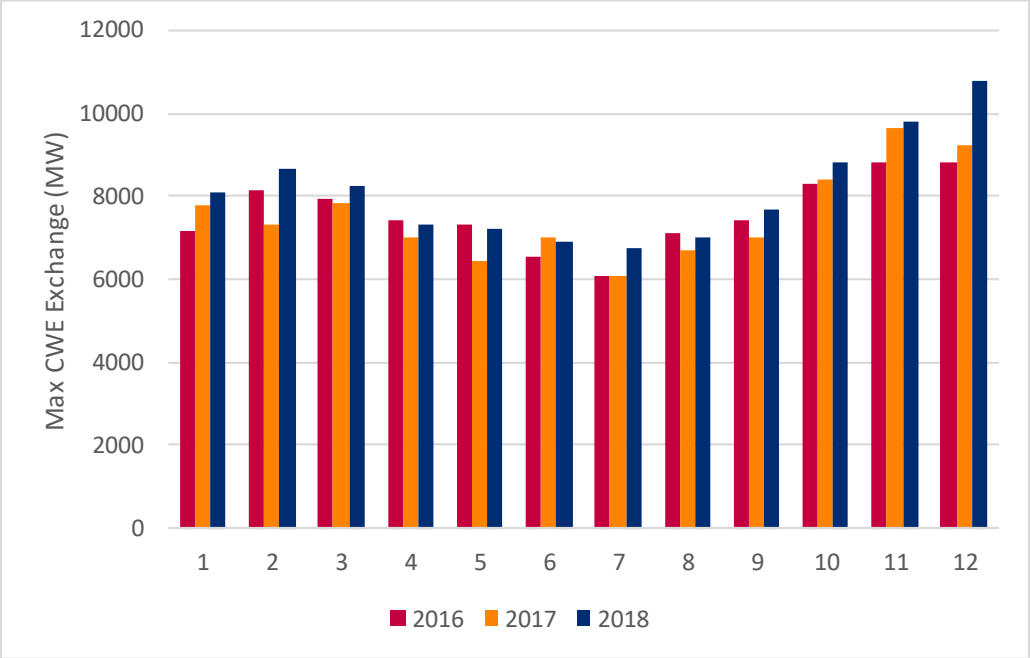


Figure 41: The monthly maximum cross-zonal exchanges in the CWE region in 2018 remained similar to recent years, but since the removal of the DE/AT/LU export limit in October 2018 with the introduction of the DE/LU-AT bidding zone split, the monthly maximums are consistently higher.

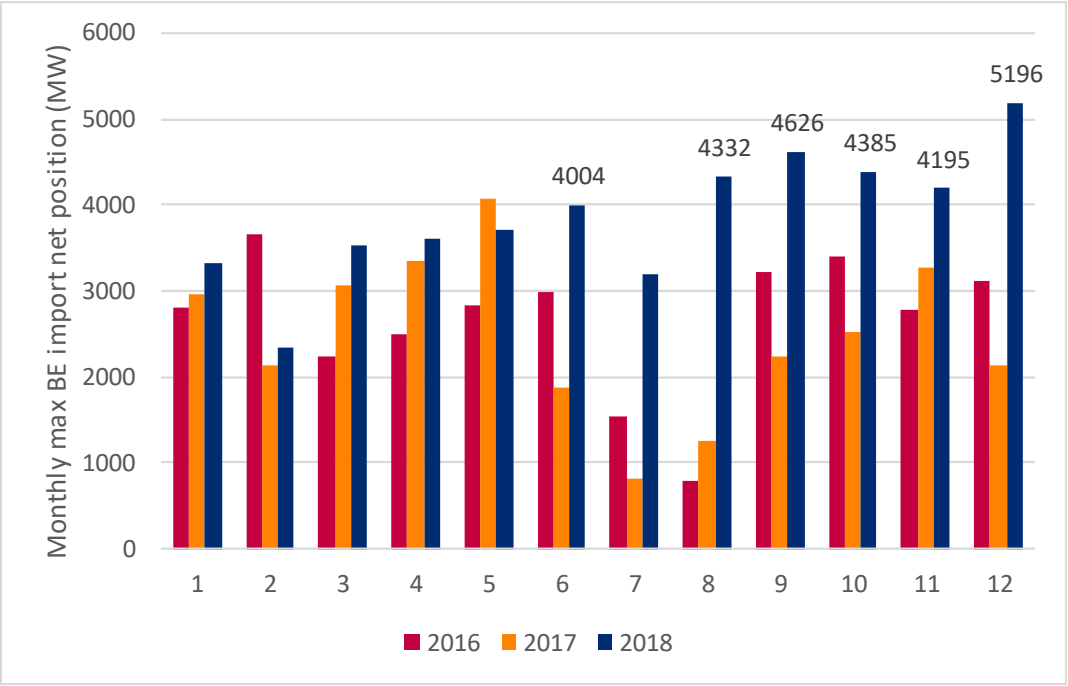


Figure 42: The combination of CWE FBMC improvements such as the introduction of the 20% minRAM and the removal of the DE/AT/LU export constraint, combined with the increase of the Belgian import limit in June 2018 from 4,500 MW to 5,500 MW, enabled higher Belgian import capacities than previous years. Especially in September – December 2018, when Belgium faced tight market conditions, Belgian import values hit historical records.

4.3. STATISTICS

4.3.1. Long-term transmission capacity auctions

Yearly auctions

52. Auctioned volumes of long-term transmission rights at the Belgian borders have been relatively stable over the past 10 years, except the auctioned volumes at the southern border in the export direction (BE=>FR). In 2016, there the yearly auctioned capacity dropped from 400 MW to 200 MW and in 2018 this value was further reduced down to 100 MW due to the outage planning related to HTLS upgrade. The volumes of long-term capacity remain the highest at the southern border in the import direction, despite a small decrease from 1,448 MW in 2017 to 1,400 MW in 2018.

53. Revenues of the yearly auctioned volumes in 2018 were 40.23 M€, comparable to the 41.95 M€ in 2017. Compared to 2017, the price for transmission capacity from France to Belgium (FR=>BE) increased, while the price for transmission capacity from the Netherlands to Belgium (NL=>BE) decreased. Prices in the export direction increased slightly at both borders (BE=>FR and BE=>NL).

	FR=>BE			BE=>FR			NL=>BE			BE=>NL			Total
Year	Cap	Price	Revenu	Cap	Price	Revenu	Cap	Price	Revenu	Cap	Price	Revenu	Revenu
	(MW)	(€/MW)	(M€)	(MW)	(€/MW)	(M€)	(MW)	(€/MW)	(M€)	(MW)	(€/MW)	(M€)	(M€)
2007	1299	2.06	23.44	400	0.25	0.88	467	0.11	0.45	467	3.45	14.13	38.90
2008	1300	0.90	10.28	400	0.56	1.97	468	1.57	6.45	468	2.04	8.37	27.06
2009	1300	0.88	10.02	400	0.81	2.84	468	3.07	12.59	468	1.34	5.49	30.94
2010	1297	0.16	1.82	400	3.46	12.12	467	2.02	8.25	467	0.80	3.27	25.46
2011	1449	0.06	0.76	400	0.69	2.42	467	1.10	4.48	465	0.59	2.40	10.06
2012	1447	0.10	1.27	400	0.52	1.83	467	0.85	3.48	466	2.20	9.01	15.59
2013	1449	1.07	13.58	400	0.72	2.52	468	1.95	7.99	471	3.04	12.56	36.66
2014	1450	1.21	15.37	400	1.16	4.06	468	1.24	5.08	468	4.41	18.06	42.58
2015	1450	2.86	36.33	399	0.39	1.36	467	5.44	22.26	468	1.25	5.10	65.06
2016	1449	0.96	12.22	200	1.25	2.20	468	3.22	13.24	468	1.39	5.71	33.37
2017	1448	1.16	14.71	200	2.16	3.78	473	4.44	18.40	473	1.22	5.06	41.95
2018	1400	1.50	18.40	100	2.31	2.02	473	2.93	12.14	473	1.85	7.67	40.23

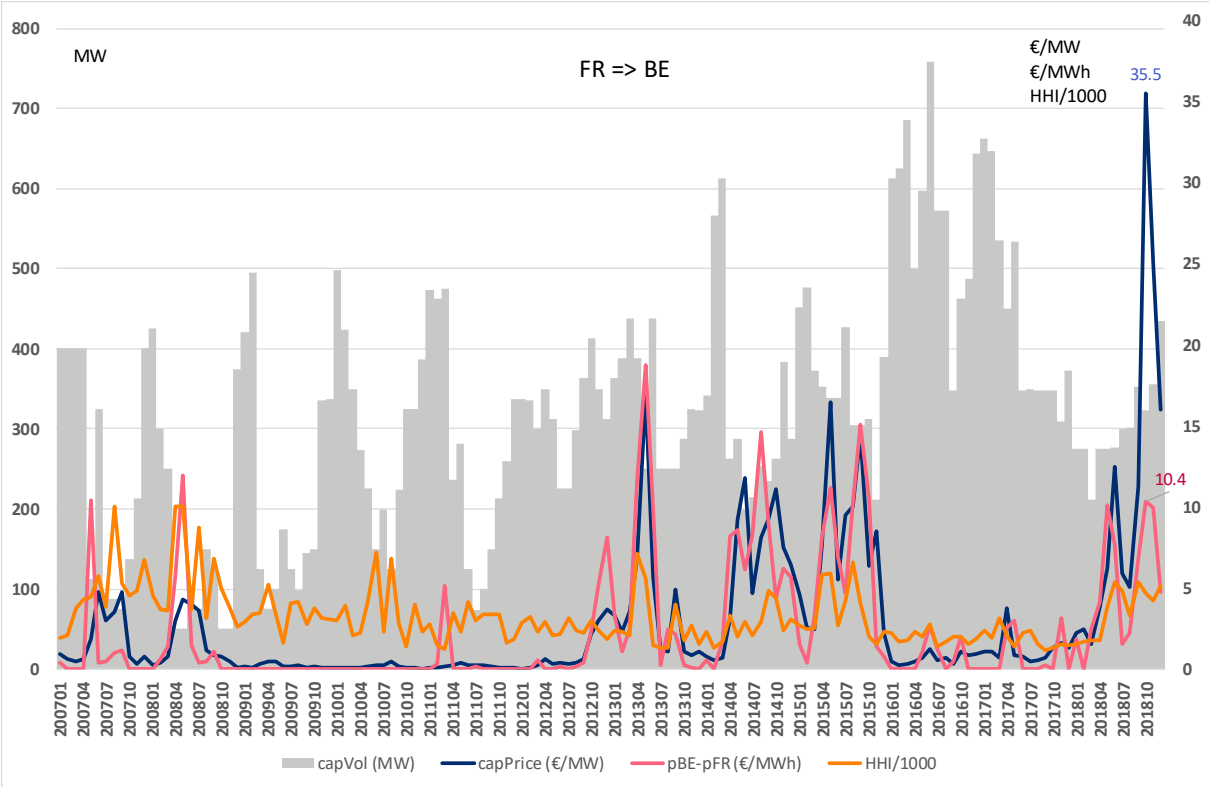
Table 16: Annual long term import and export capacities (MW), transmission rights (€/MW) and resulting revenues (€) at the Belgian border with France and the Netherlands. Sources: Elia, CREG

Monthly auctions

Revenues of long-term transmission capacity auctions (M€)			
Year	Yearly Auctions	Monthly Auctions	Total
2007	38.9	16.0	54.9
2008	27.1	11.6	38.7
2009	30.9	12.3	43.2
2010	25.5	8.1	33.6
2011	10.1	5.2	15.3
2012	15.6	8.5	24.1
2013	36.7	20.7	57.4
2014	42.6	24.1	66.6
2015	65.1	37.1	102.1
2016	33.4	30.8	64.2
2017	42.0	22.7	64.6
2018	40.2	61.2	101.4

Table 17: Total revenues of long-term capacity rights from the yearly and monthly auctions.

54. Revenues of the monthly auctioned transmission capacities amounted to 61.2 M€, the largest value ever for monthly revenues. 64% of these revenues were generated by the auctioned capacities for October (27%), November (18%) and December 2018 (16%). The revenues of the yearly and monthly auctions combined yields a total revenue of 101.4 M€, close to the maximum value of 102.1 M€ obtained in 2015. In contrast to 2015, the highest share of revenues in 2018 resulted from the monthly auctions. At the time of the yearly auctions, market parties could not have anticipated the impact of the unplanned outages of four of the five Belgian nuclear power plants. These outages, which significantly affected the Belgian production capacity from October to November 2018, were communicated by Engie at the end of August and mid-September (see footnote 23, page 49).



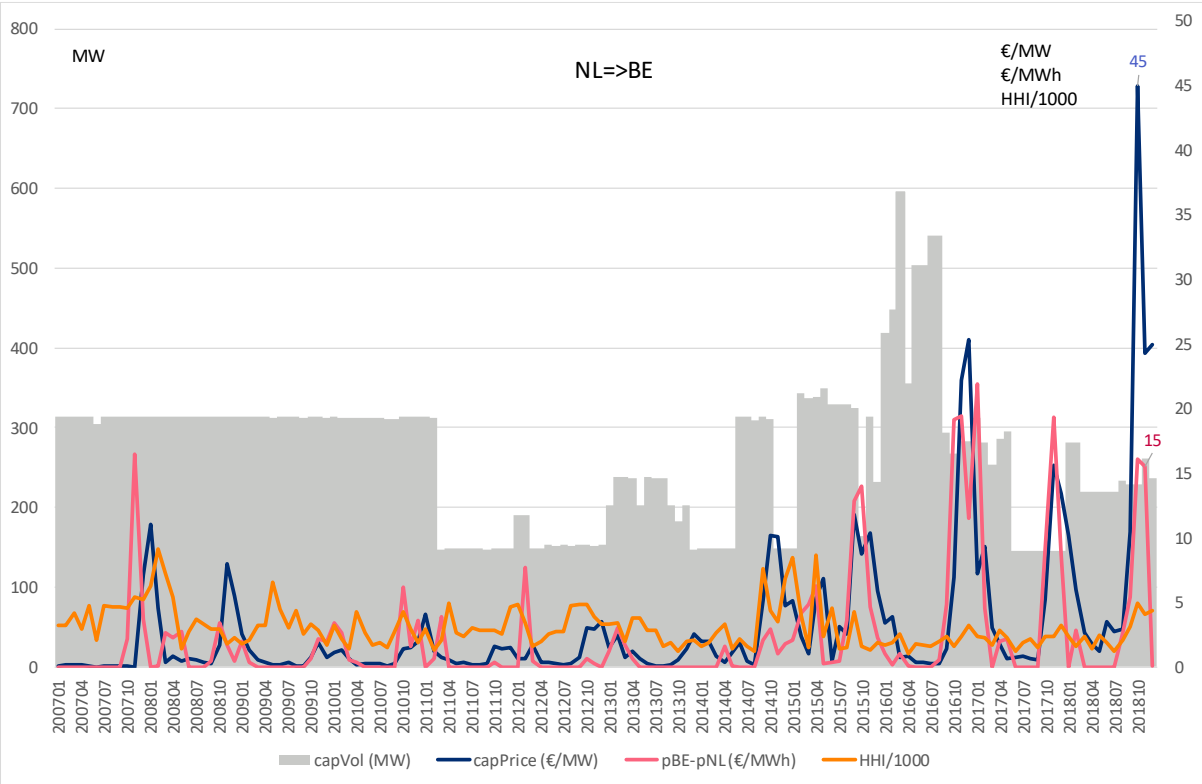


Figure 43: Monthly long term IMPORT capacity auctions at the French border (top) and at the Dutch border (bottom). The auctioned volumes ('capVol', MW) vary on a monthly basis. The better the auction price ('capPrice', in €/MW) and the monthly-averaged day-ahead price in the given direction ('pBE-pFR' and 'pBE-pNL', in €/MWh) are correlated, the better the market was able to anticipate the price spreads. The level of competition, which depends on the number of participating market players, is measured by the HHI-index ('HHI/1000').

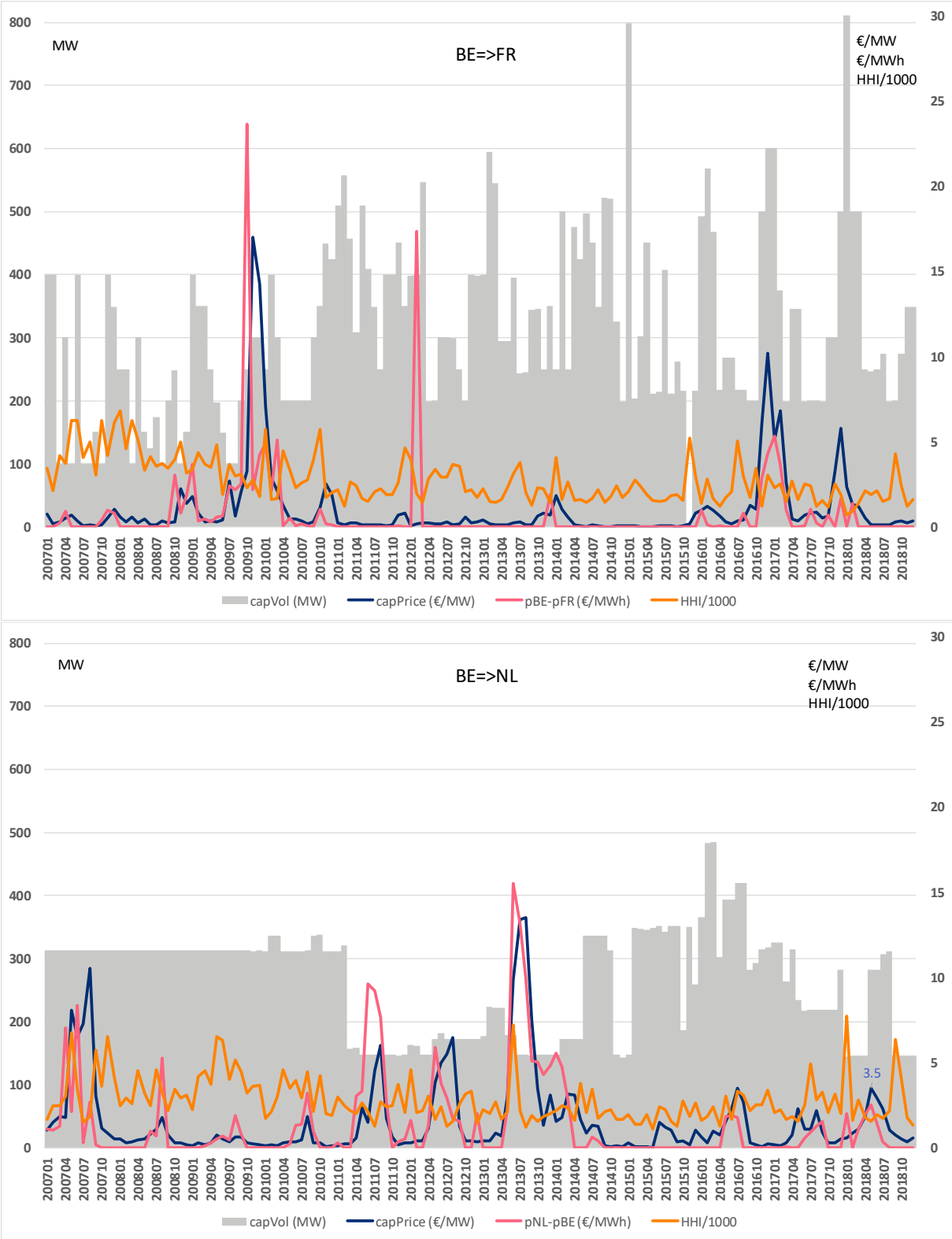


Figure 44 : Monthly long-term EXPORT capacity auctions at the French border (top) and at the Dutch border (bottom). The auctioned volumes ('capVol', MW) vary on a monthly basis. The better the auction price ('capPrice', in €/MW) and the monthly-averaged day-ahead price in the given direction ('pFR-pBE' and 'pNL-pBE', in €/MWh) are correlated, the better the market was able to anticipate the price spreads. The level of competition, which is function of the number of participating market players, is measured by the HHI-index ('HHI/1000').

4.3.2. Day-ahead cross-zonal exchange

55. For the second year in a row, Belgium import levels have broken records. In December 2018, Belgium was able to import a historically high volume of 5,196 MW. This is an increase of 1,127 MW or 28% compared to the previous record of 4,069 MW achieved in May 2017. The 2017 import record was already broken in August 2018, with a net import position of 4,332 MW. From August to December, maximum import net positions ranged from 4,199 MW to 5,196 MW.

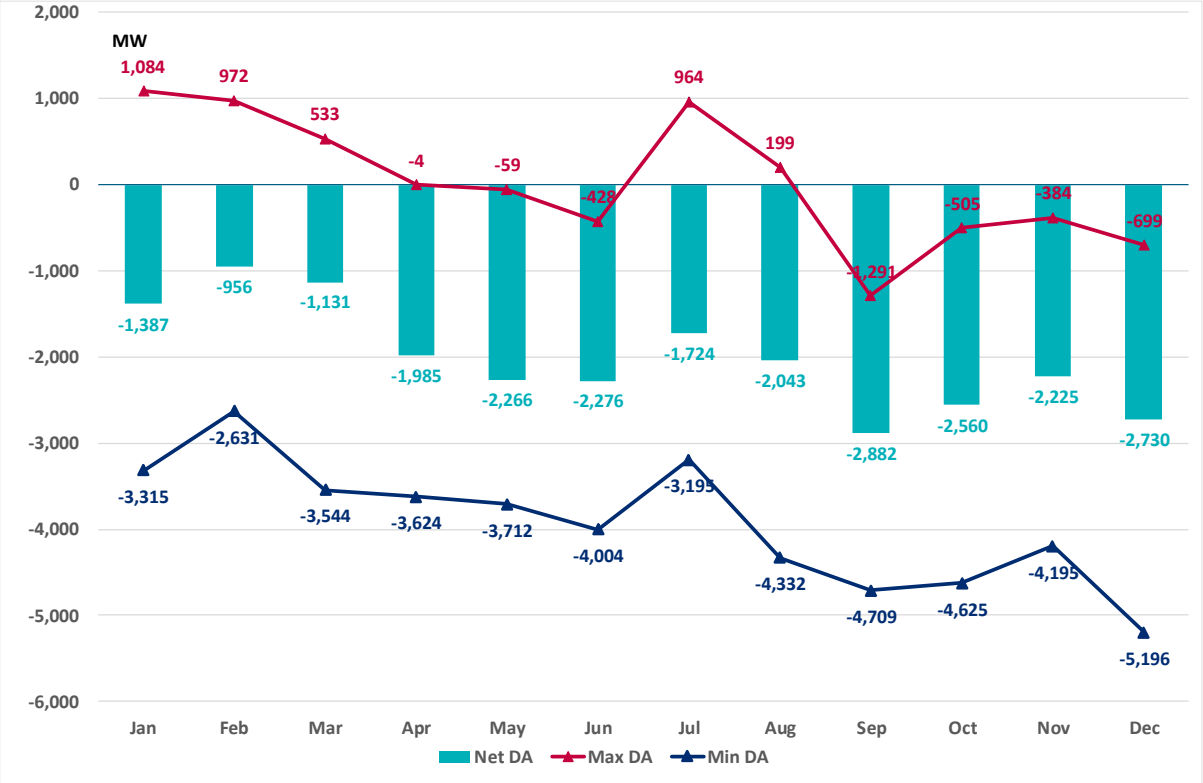


Figure 45: Monthly average ('Net DA'), maximum ('Max DA') and minimum ('Min DA') Day-ahead Net Position for Belgium. Positive values indicate export, negative values indicate import.

Net Position in day-ahead + long term (MW)					
2018	**BE**	**NL**	**FR**	**DE/LU + AT**	**CWE**
Jan	-1,387	-1,161	-361	2,908	3,988
Feb	-956	-31	-4,005	4,992	5,359
Mar	-1,131	-1,443	-1,210	3,783	4,732
Apr	-1,985	-2,659	1,399	3,245	5,135
May	-2,266	-2,997	3,534	1,729	5,392
Jun	-2,276	-2,437	3,514	1,198	4,907
Jul	-1,724	-1,917	1,680	1,961	4,073
Aug	-2,043	-1,132	1,088	2,087	4,182
Sep	-2,882	-804	979	2,706	4,237
Oct	-2,560	26	553	1,980	3,738
Nov	-2,225	-449	-630	3,305	4,217
Dec	-2,730	-955	-475	4,160	5,194
Average	-2,019	-1,338	534	2,823	4,590

Table 18: Monthly average Net Positions of the 4 CWE bidding zones in 2018 resulting from the CWE day-ahead and long term commercial exchanges. To allow comparison with historical data, net positions of the German-Luxembourg (DE/LU) and Austrian (AT) bidding zone after the DE/LU-AT bidding zone split, have been lumped together. In 2017, Belgium was net importing all months, except from July and August.

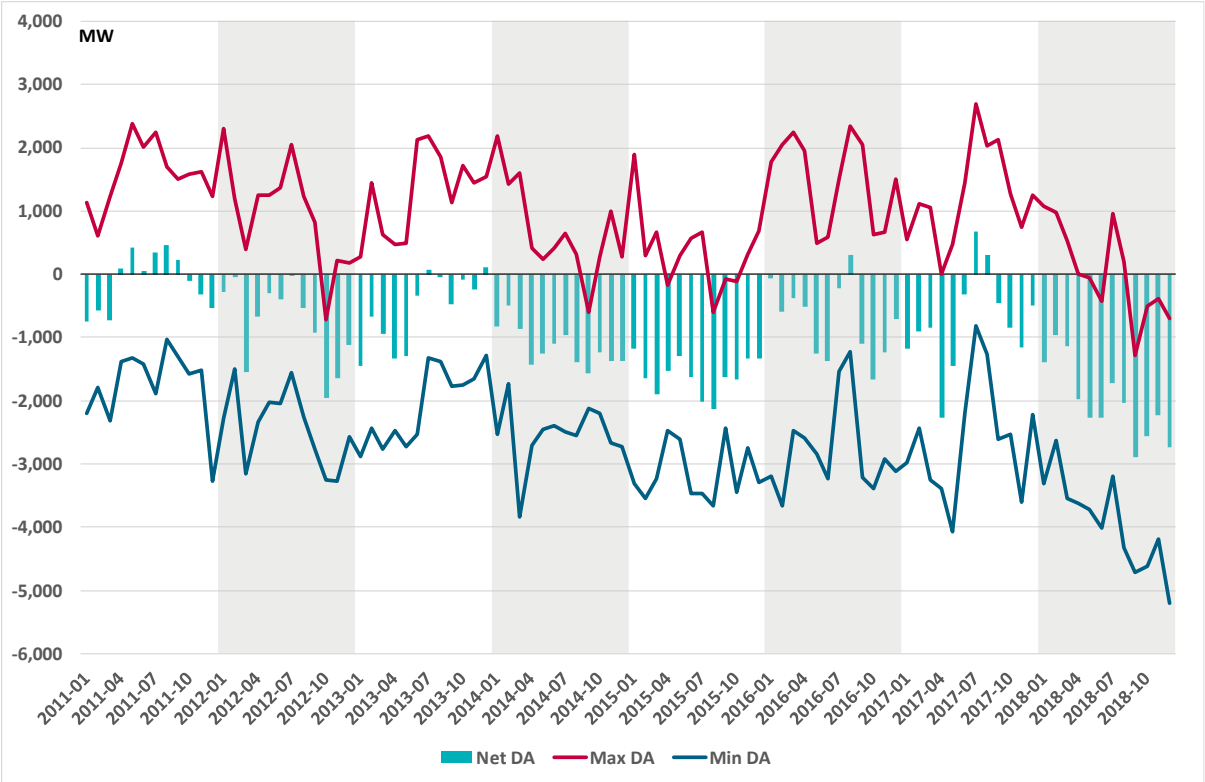


Figure 46 : Evolution of the monthly average ('Net DA'), maximum ('Max DA') and minimum ('Min DA') Day-ahead Net Position (including long-term nominations) for Belgium since 2011. Positive values indicate export, negative values indicate import.

56. The monthly average net position also broke records in 2018. . The average net import position of 2,882 MW in September 2018 and 2,730 MW in December 2018 were the highest monthly averaged Belgian import positions ever. Compared to the previous historical record of 2,261 MW value achieved in April 2017, this is an increase of 27% and 20% respectively.

57. Belgium was a net importer in all months. From January to March and in July, Belgium exported some hours but the export level remained relatively low compared to previous years.

58. On a yearly basis, imports were 2,019 MW on average in 2018, nearly triple the volumes of 728 MW and 736 MW in 2016 and 2017 but similar to the day-ahead volumes of 1,929 MW and 2,392 MW in 2014 and 2015 (Table 19). As was the case in 2014 and 2015, Belgium was confronted with sustained outages of multiple nuclear power plants in 2018. Sustained outages of nuclear power plants were also the reason why France, traditionally an exporting country, was a net importer in 2016 and 2017. In 2018, in the absence of sustained nuclear power plant outages, France regained its net export status. The DE/AT/LU-bidding zone remains the highest net exporting bidding zone in the CWE region. In 2018, it reached an annual average net position of 3,701 MW, an increase of 37% compared to its annual average net position in 2017. This significant increase is explained by the market conditions but also by the measures taken at the level of CWE FBMC, such as the implementation of the 20% minRAM at the end of April 2018 and the introduction of the DE/LU-AT bidding zone border, and the removal of the DE/AT/LU export in October 2018 (see discussion Section 4.2). Day-ahead exchanged cross-zonal volume in the CWE-region increased from 3,736 MW annual average in 2017 to 4,590 MW annual average in 2018, an increase of 23%. CWE cross-zonal exchanges therefore reached the highest value since the start of the CWE market coupling in 2011.

Yearly average Day-ahead + Long term net position (MW)					
	BE	**NL**	**FR**	**DE/LU+AT**	**CWE**
2011	-255	-967	884	338	3106
2012	-1049	-2019	326	2743	4055
2013	-1109	-2399	361	3148	4415
2014	-1929	-2015	1240	2704	4302
2015	-2392	-1289	656	3025	4419
2016	-728	-1032	-736	2496	3648
2017	-736	-663	-1300	2699	3736
2018	**-2019**	**-1338**	**534**	**3701**	**4590**
Average	-1277	-1465	246	2607	4034

Table 19: Annual net import (-) and export(+) volume on the CWE-day-ahead market, including the long-term nominations. To allow comparison with historical data, net positions of the German-Luxembourg (DE/LU) and Austrian (AT) bidding zone after the DE/LU-AT bidding zone split have been lumped together.

4.3.3. Intraday cross-zonal exchange

59. Since the start of the intraday market coupling in 2007, intraday exchanged volumes have shown an upward trend. The intraday market is still primarily used for optimizing portfolios rather than energy sourcing. This can be concluded from the fact that on average, intraday cross-zonal exchanges do not significantly contribute to the monthly and annual average Belgian net position while hourly exchanges can be high in both import and export directions.

60. In 2018, the annual average contribution of the intraday cross-zonal exchange to the export net position was +180 MW, and -163 MW to the import net position (see Table 20). Despite the fact that this contribution of the intraday cross-zonal exchanges to the annual Belgian export and import positions remained limited, there was a significant increase of 46% and 24% compared to 2017.

61. The monthly contributions in 2018 varied between -85 MW in July to +55 MW in June. Monthly averages for export varied from between 7 MW in February to 55 MW in July. Monthly averages for import varied from -100 MW in November to -247 MW in July.

62. While the contribution of intraday cross-zonal exchange to the annual and monthly basis remained limited, the contribution on an hourly level can be much higher. In 2018, the monthly maximum net intraday export position ranged from 670 MW to 1,291 MW and the monthly maximum net import positions ranged from -360 MW to -1,611 MW. These values remained below the maximum of 1,714 MW intraday export in May 2017 and below the maximum of 1,713 MW intraday import in January 2017.

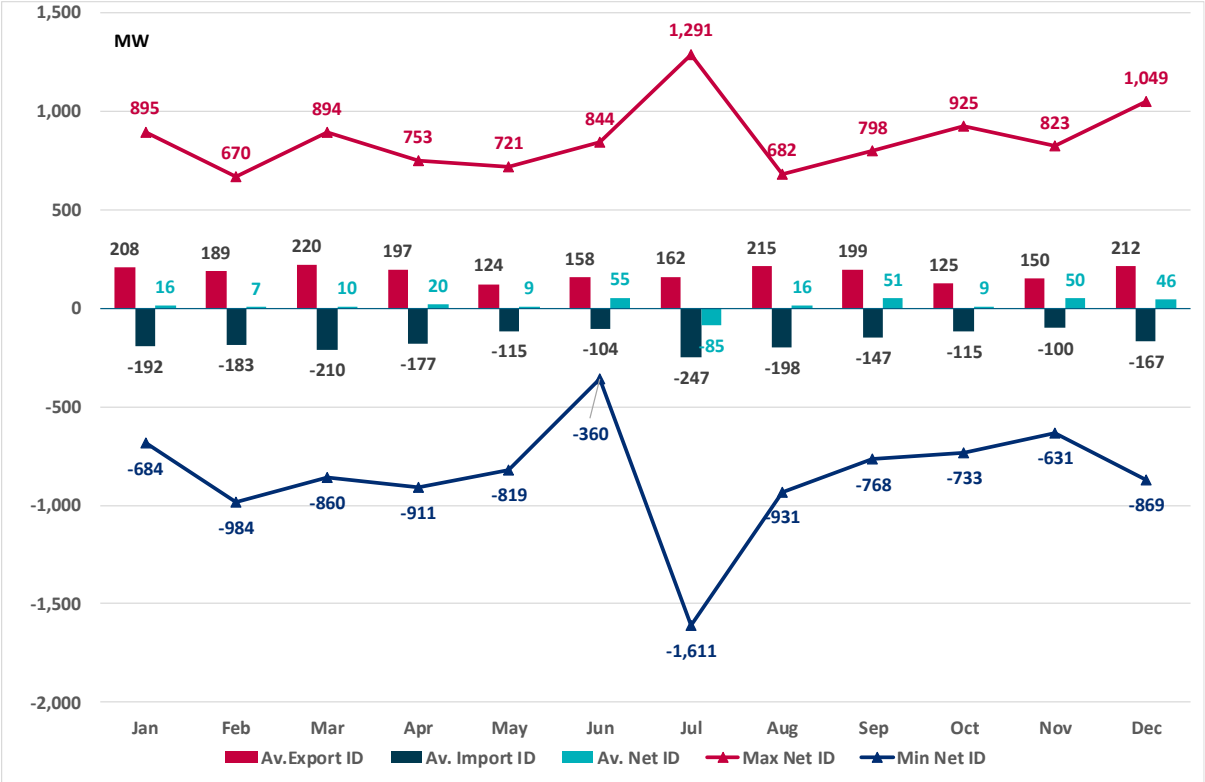


Figure 47: Monthly average export net positions ('Av Export ID'), average import nominations ('Av. Import ID') and resulting average net position ('Av. Net ID'), along with the monthly maximums ('Max Export ID', 'Max import ID') in 2018.

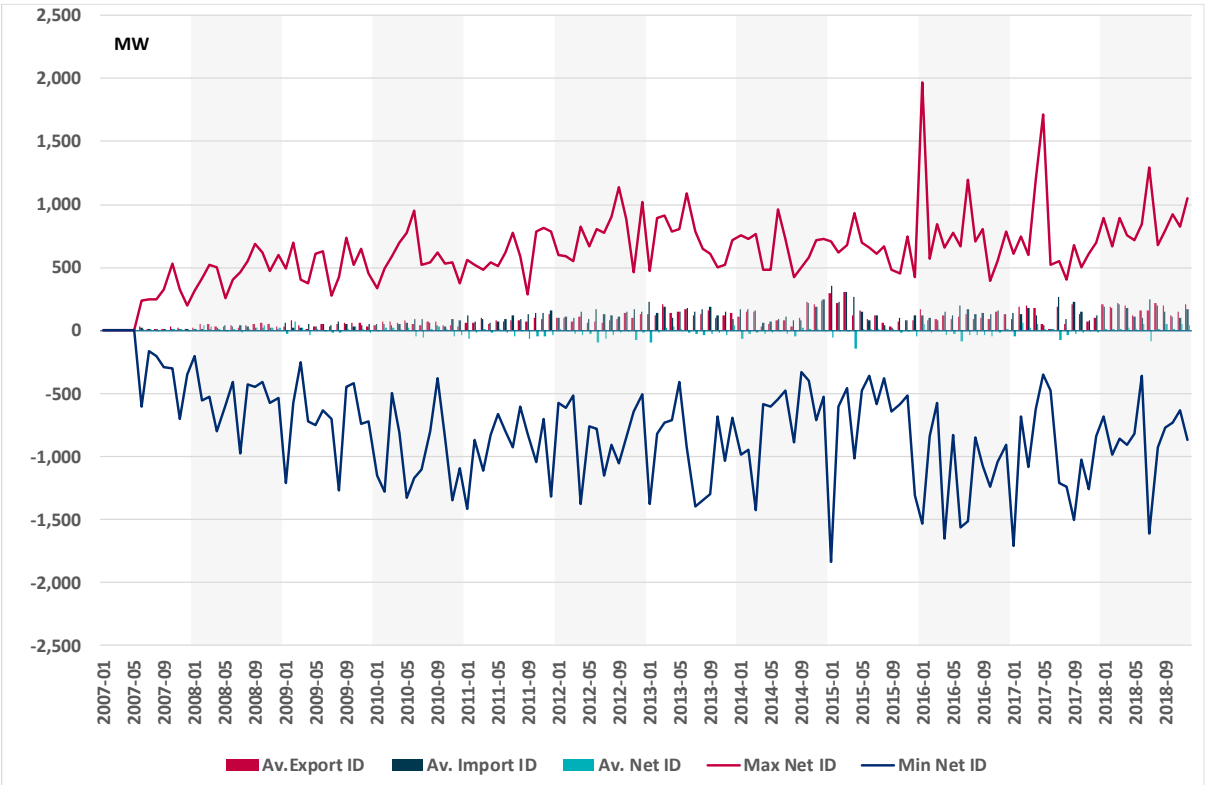


Figure 48: Evolution of the monthly average export net positions ('Av Export ID'), average import nominations ('Av. Import ID') and resulting average net position ('Av. Net ID'), along with the monthly maximums ('Max Export ID', 'Max import ID'), since 2007.

4.3.4. Overview of cross-zonal exchanges

63. Figure 49 and Table 21 summarize the contribution of the long term, day-ahead and intraday markets in total annual Belgian imported and exported volumes over the past 12 years. The figures complement the main findings discussed above: Combining day-ahead and intraday cross-zonal exchanges, Belgium imported on average 2,466 MW or 89% more than in 2017 and exported on average 453 MW or 19% less. In total, the annual average Belgian net position was -2,013 MW. This remains below the annual average Belgian net position of -2,398 MW in 2015, characterized by sustained nuclear outages as was the case in 2018. In contrast to 2018, 29% of the import in 2015 was explicitly sourced on the long-term market (Table 21). Since the introduction of Financial Transmission Rights (FTR) in January 2016, long-term transmission rights no longer have to be nominated. Their corresponding exchanges are included in the day-ahead exchanges. Firmness of long-term transmission rights is guaranteed through the so-called 'LTA-patch'. The latter virtually increases the day-ahead flow based domain if it is too small to allow all long-term exchanges.

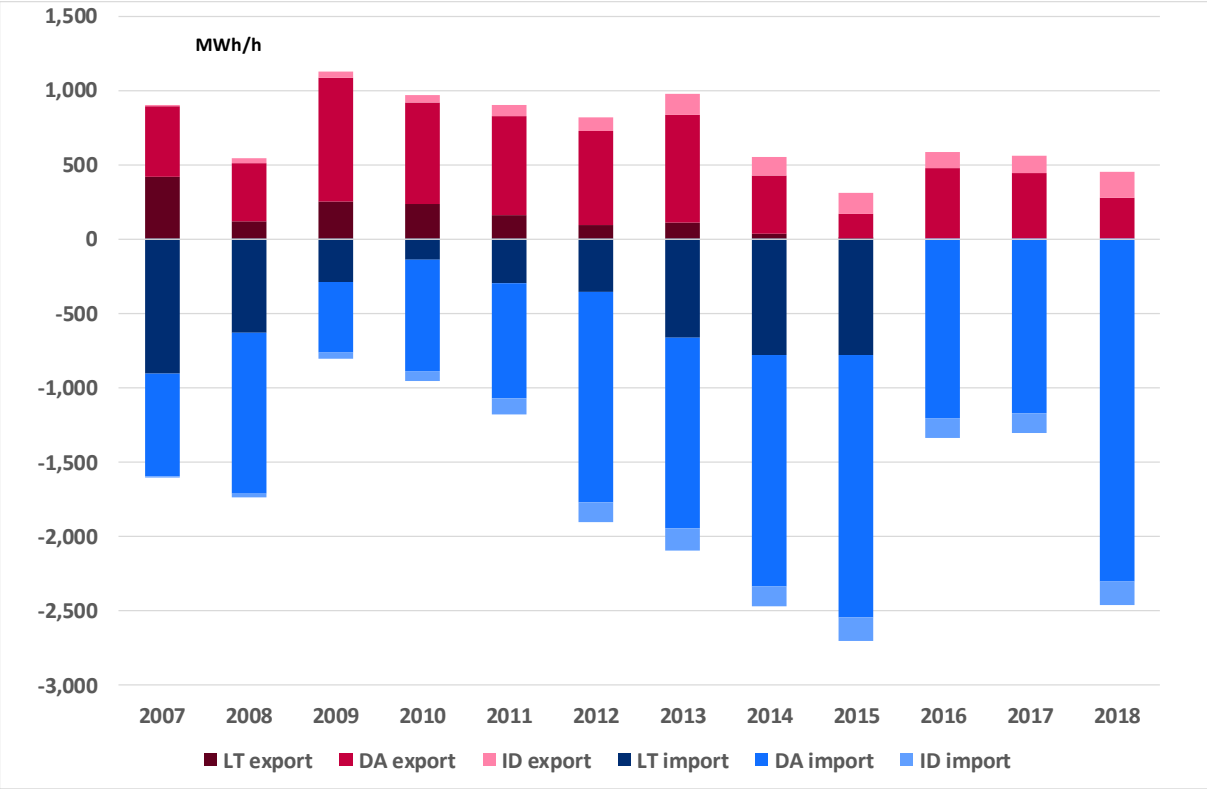


Figure 49: Yearly average imported and exported volumes on the long term (LT), day-ahead (DA) and intraday (ID) markets.

	Long Term (Average, MW)			Day-ahead (Average, MW)			Intraday (Average, MW)		
Year	**Export**	**Import**	**Net**	**Export**	**Import**	**Net**	**Export**	**Import**	**Net**
2007	415	903	-488	474	697	-223	10	8	2
2008	119	635	-516	387	1,082	-696	41	25	16
2009	250	288	-37	830	477	353	47	44	3
2010	237	136	101	677	754	-77	56	62	-6
2011	158	299	-141	664	777	-112	81	110	-29
2012	94	354	-260	632	1,421	-789	95	129	-34
2013	110	661	-551	725	1,283	-558	139	154	-15
2014	31	783	-752	395	1,553	-1,158	122	139	-17
2015	1	780	-779	168	1,769	-1,600	137	156	-19
2016	0	0	0	474	1,206	-732	114	136	-22
2017	0	0	0	439	1,175	-736	123	131	-8
2018	0	0	0	273	2,303	-2,029	180	163	17

Table 20: Annual average export, import and net exchanges on the long term, day-ahead and intraday markets.

	LT+DA+ID (Average, MW)			Share in Export			Share in Import		
Year	**Export**	**Import**	**Net**	**%LT**	**%DA**	**%ID**	**%LT**	**%DA**	**%ID**
2007	899	-1,609	-709	46%	53%	1%	56%	43%	0%
2008	546	-1,742	-1,196	22%	71%	8%	36%	62%	1%
2009	1,128	-808	319	22%	74%	4%	36%	59%	5%
2010	970	-953	17	24%	70%	6%	14%	79%	7%
2011	903	-1,185	-282	17%	74%	9%	25%	66%	9%
2012	820	-1,904	-1,084	11%	77%	12%	19%	75%	7%
2013	975	-2,099	-1,124	11%	74%	14%	32%	61%	7%
2014	548	-2,475	-1,926	6%	72%	22%	32%	63%	6%
2015	306	-2,705	-2,398	0%	55%	45%	29%	65%	6%
2016	588	-1,342	-754	0%	81%	19%	0%	90%	10%
2017	562	-1,306	-744	0%	78%	22%	0%	90%	10%
2018	453	-2,466	-2,013	0%	60%	40%	0%	93%	7%

Table 21: Share of the long term (LT), day-ahead (DA) and intraday (ID) markets in Belgian electricity exports and imports.

4.3.5. Transit flows

64. Transit flows are physical flows crossing the Belgian control area, resulting from commercial exchanges between two other bidding zones. With the ATC-method, bilateral commercial exchanges are translated into capacity nominations on individual borders. For some commercial exchanges, this results in a transit flow crossing Belgium from North to South (Transit North=>South). For other commercial exchanges the resulting transit flow crosses Belgium from South to North (Transit South=>North). The net transit flow, shown in Figure 50, is the result of all transit flows. Positive flows indicate a resulting flow in the North-South direction.

65. Prior to May 2015, the computed transit flows showed a clear pattern, with an almost constant value for the maximum transit flow from FR=>NL and with a seasonal pattern for the maximum transit flow from NL=>FR. After that date, there was much more variation in the calculated transit flows, especially in the direction FR=>NL. In addition, much larger transit flows are recorded in both directions. The difference between before and after May 2015 may be due to the computation method, the introduction of FBMC and the situation in the French market in 2016 and 2017 resulting from the sustained outage of several nuclear power plants, turning France from a net exporting bidding zone to a net importing bidding zone (see also Table 19)

66. Since the go-live of FBMC in May 2015, record values have been recorded in both directions, with the highest values recorded in the direction South-North. In 2018, transit flows reached a record value in the direction South-North of 4,574 MW, compared to the maximum of 4,245 MW in 2016. The

transit flows in the North-South direction remained well below the maximums calculated in 2016 and 2017 of respectively 2,302 MW and 2,957 MW. Note that since 2015, with FBMC, transit flows are calculated from the combination of zonal Net Exchange Positions, whereas in ATC these were calculated from the individual zone-to-zone commercial exchanges. With FBMC, individual zone-to-zone commercial exchanges cannot be uniquely defined.

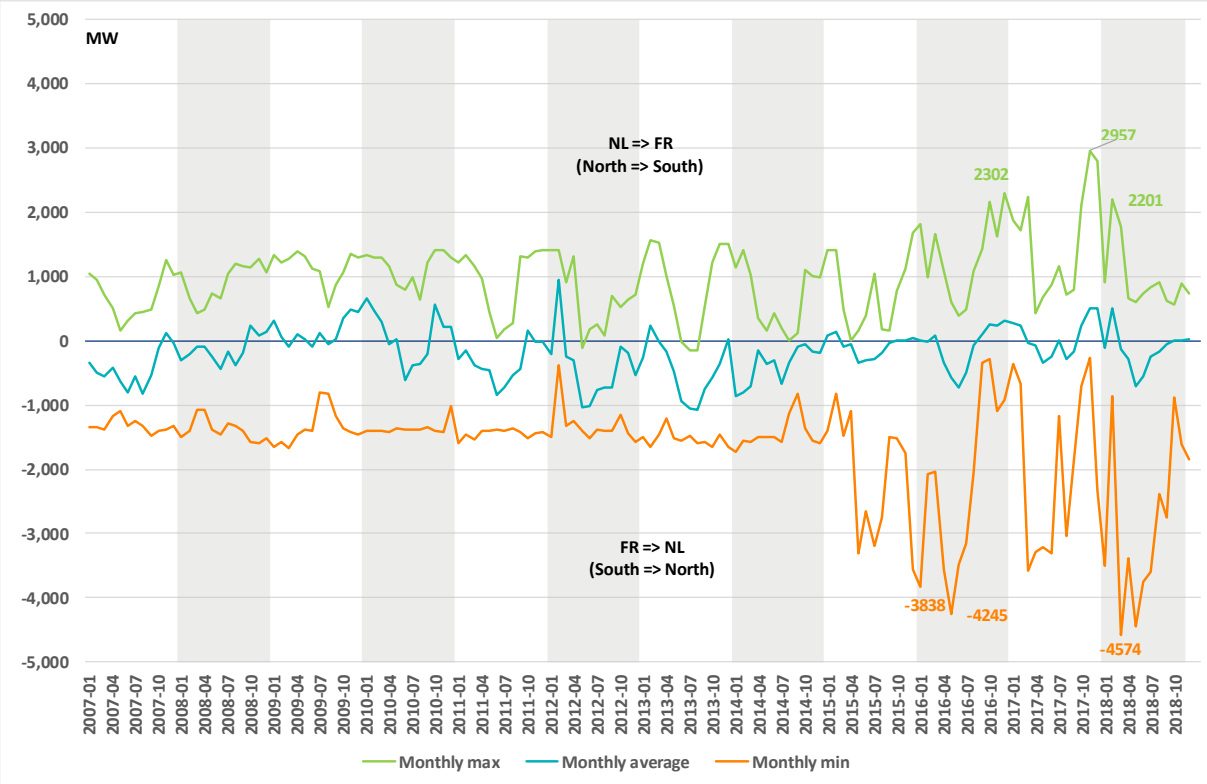


Figure 50: Monthly average, maximum and minimum net transit flows through Belgium.

67. During the first months of 2018, when France was importing from the CWE region, transit flows through Belgium were mainly North-South. During summer, when the Netherlands was importing from the CWE region, transit flows were mainly South-North (see also monthly CWE net positions in Table 18).

Year	Transit NL=>FR	Transit FR=>NL	Transit Net NL=>FR	pFR-pNL (€/MWh)
2007	137	-569	-432	-1
2008	144	-281	-136	-1
2009	327	-187	140	4
2010	307	-239	68	2
2011	109	-454	-345	-3
2012	120	-538	-418	-1
2013	140	-597	-457	-9
2014	25	-418	-393	-7
2015	56	-146	-89	-2
2016	136	-236	-100	5
2017	207	-158	49	6
2018	111	-259	-147	-2
Average	152	-340	-188	-1

Table 22: Mean transit flows via Belgium from 2007 to 2018. Transit flows in 2018 were primarily South-North, as in most years. - Sources: Elia and CREG

68. Table 22 shows the annual mean transit flows in both directions and the resulting net transit flow arising from all CWE cross-zonal exchanges (long-term, day-ahead and intraday). Note again that with FBMC, one obtains the Net Transit flows resulting from the set of zonal Net Positions. The breakdown of this Net Transit flow into Transit NL=>FR and Transit FR=>NL is not uniquely defined and is therefore somewhat arbitrary.

69. Since 2011, the net transit flows through Belgium are predominantly South to North. This was not the case for 2017, because France had imported during 10 of the 12 months. In 2018, transit flows through Belgium arising from CWE exchanges were again predominantly South-North, with an average of 147 MW (Table 22).

4.3.6. Loop flows

70. Since 1 January 2017, the level of loop flows in the day-ahead market coupling through the Belgian zone have been published on a daily basis on the Elia website[24]. The calculation methodology adopted by Elia is based on data from the FBMC process. The loop flows in the day-ahead market coupling are calculated based on the D2CF files of the base case. The calculation method is published on the Elia website.

71. Loop flows correspond to physical flows observed on a network element resulting from commercial exchanges inside another bidding zone. They correspond to externalities for economists. As discussed before, all commercial exchanges give rise to physical flows. Not all of these are considered to be "externalities". Physical flows arising from commercial exchanges *between bidding zones* (long term, day-ahead, intraday) are not. They are considered as competitive flows since the commercial exchanges go in competition for the use of the network transmission capacity. Expected physical flows arising from commercial exchanges *inside another zone*, by contrast, take priority over these flows resulting from the day-ahead market coupling. This priority access is not only market distorting, it also creates inefficiencies at the grid management level. The loop flows originating from exchanges inside other bidding zones create uncertainty for which system operators take safety margins. In turn, these safety margins reduce the capacity available for commercial exchange. It is therefore important to closely monitor the level of loop flows.

72. Based on exchanges with Elia in winter 2018, loop flows in the day-ahead market coupling are overestimated by over 600 MW on average compared to the actual loop flows in real-time. While the loop flows in the basecase in 2018 amounted to 812 MW on average (see Table 23), it means that the actual loop flows in real time were 'only' around 212 MW on average. From this, one can conclude that commercial capacity is not only reduced by loop flows, but mainly by the forecast error on these loop flows. To make things worse, this forecast error also increases the FRM, which further reduces the commercial capacity. One of the identified measures to improve D-2 forecast accuracy is to include not only the best forecast of the load and production pattern in the basecase calculation, but the best forecast of what the actual production infeed is going to be. Those remedial actions will have to solve internal congestions detected in the basecase as their primary objective. As a welcome side-effect, those remedial actions will result in a reduction of loop flows in the basecase, closing the gap between the forecasted and actual loop flows. The requirement for including the best forecast of (costly) remedial actions is however not explicitly defined as mandatory in the current CWE FBMC, neither in the foreseen CORE FBMC. Tackling this forecast accuracy issue is identified by CREG as one of the key measures to further improve the functioning of the market coupling.

[24] See Elia website, Data download, Category "Interconnection" on http://www.elia.be/en/grid-data/data-download

73. Figure 51 shows the loop flows through Belgium calculated by Elia and based on the D-2 data since the start of FBMC (May 2015 to December 2018). Most of the hours, the result of all loop flows generated in the CWE zones through Belgium flows in the North-South direction. Statistical indicators are presented in Table 23.

	Entire year			October - December		
	2016	**2017**	**2018**	**2016**	**2017**	**2018**
Average	761	840	812	939	889	853
Minimum	-1010	-504	-2345	-680	-295	-357
Maximum	2459	2413	2448	2459	2350	2065
Standard Deviation	519	513	459	549	492	421
P95	1443	1527	1413	1624	1546	1392

Table 23: Statistical indicators on the D-2 forecasted loop flows used in the CWE FBMC capacity calculation

74. In the last three months of 2018, forecasted loop flows in D-2 were a modest 4% lower compared to the same period in 2017 (Table 23). In the last three months of 2018, a sensible decrease of loop flows in the D-2 forecasts was expected because of the CWE TSO agreement on a more extensive use of the PSTs in the capacity calculation to reduce loop flows when adequacy risks in Belgium were expected and, more structurally, because of the introduction of the DE/LU-AT bidding zone border on 1 October 2018 (see also Section 4.2). This expected reduction may have been partially offset by the loss of one of the PSTs at the Belgian border. The maximum value recorded during those months was 2,065 MW, being sensibly lower than the 2,350 MW maximum recorded the same period in 2017. On 26 September 2018, a few days before the DE/LU-AT bidding zone split, a record value of 2,448 MW in the North-South direction was recorded. In March 2018 a record value in the South-North direction of -2345 MW was recorded, though this value is a clear outlier as can be deducted from Figure 52.

75. With further evolutions in the methodologies for capacity calculation and redispatching and countertrading methodologies in the CORE region, it is expected that the level of loop flows in the basecase will further reduce. As discussed in paragraph 72 above, improving forecast accuracy of the D-2 calculations will make a major contribution in reducing loop flows. This can be achieved by including not only the best forecast of the load and production pattern in the basecase calculation, but the best forecast of all remedial actions, both costly and non-costly.

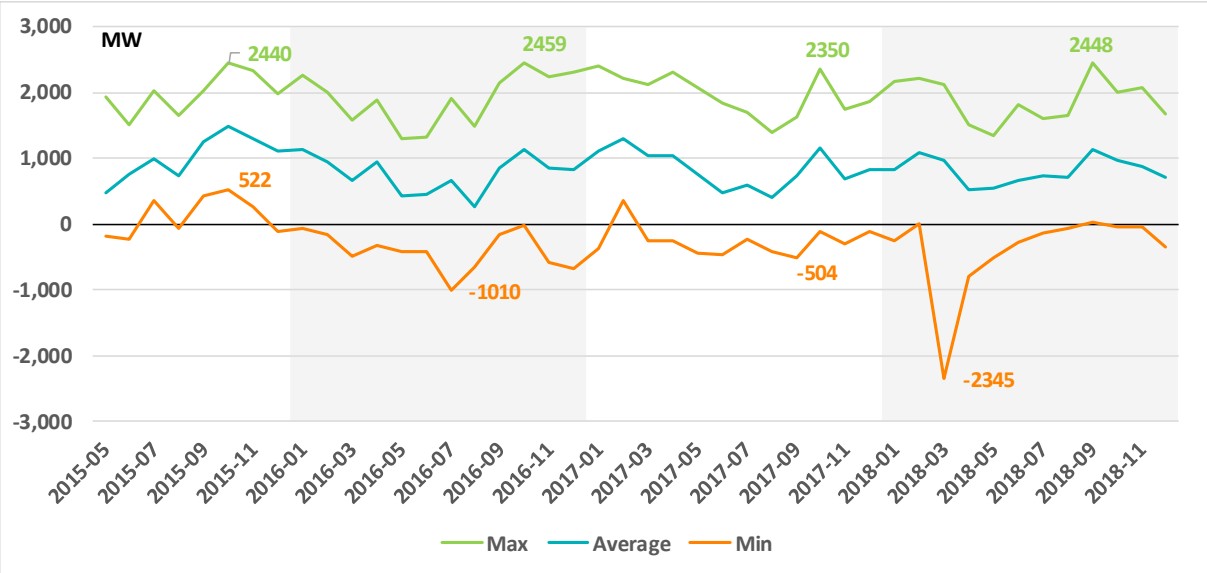


Figure 51: Maximum, minimum and monthly averaged loop flows through Belgium, forecasted in D-2. Positive values indicate loop flows in the direction North-to- South, negative values loop flows in the direction South-to-North.
Sources: Elia and CREG

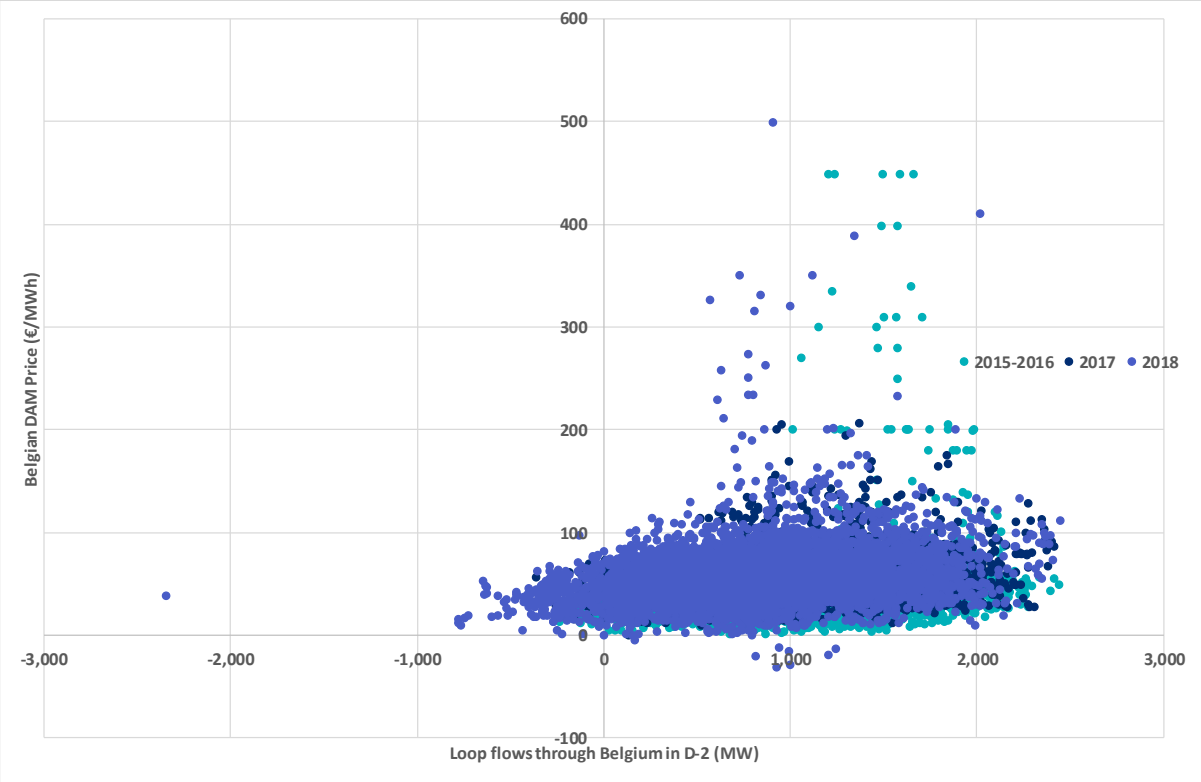


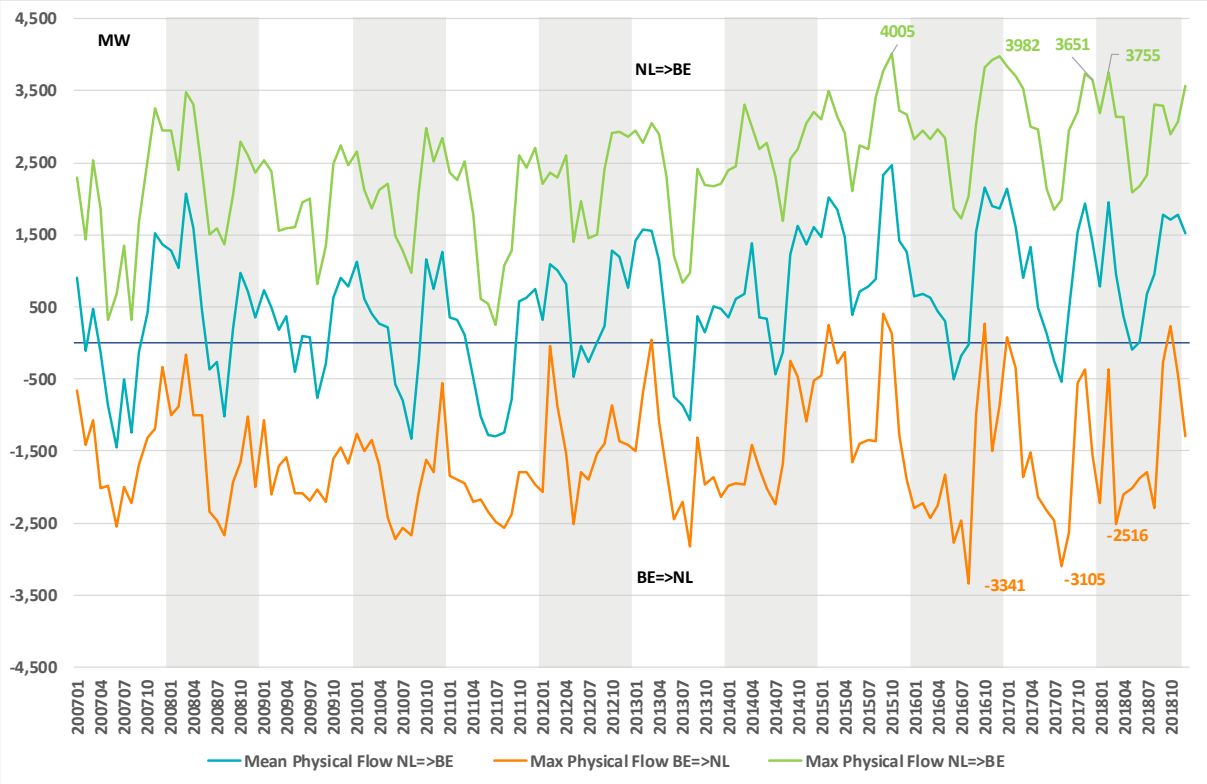
Figure 52: Belgian day-ahead prices versus D-2 loop flows for all hours in the monitoring period July 2015 to December 2016 (turquoise), 2017 (dark blue) and 2018 (light blue). Positive loop flows indicate physical flows crossing the Belgian network from North to South. In 2018, price spikes above 200 €/MWh were only observed when the D-2 loop flows through Belgium were above 500 MW.
Sources: Elia and CREG

4.3.7. Physical flows

76. Since the go-live of FBMC, physical flows on the cross-zonal lines have reached higher maximum values then with the ATC-based market coupling (Figure 53). In 2018, the following maximums were reached:

- On the Northern border, a maximum of 3,755 MW (NL=>BE) was recorded in February 2018 and a maximum of 2,516 MW (BE=>NL) in March 2018. These values do not exceed the maximums of respectively 4,005 MW recorded in 2015 and 3,341 MW recorded in 2017.
- On the Southern border, a maximum of 2,821 MW (BE=>FR) was recorded March 2018 and a maximum of 4,196 MW (FR=>BE) in December 2018. This is respectively lower than the maximum of 3,218 recorded in 2016 (BE=>FR), and higher than the previous record of 3,962 MW recorded in 2016 (FR=>BE).

High physical flows arise from high volumes of cross-zonal exchange (Belgian import, Belgian export and Transit Flows through Belgium) and/or high real-time loop flows.



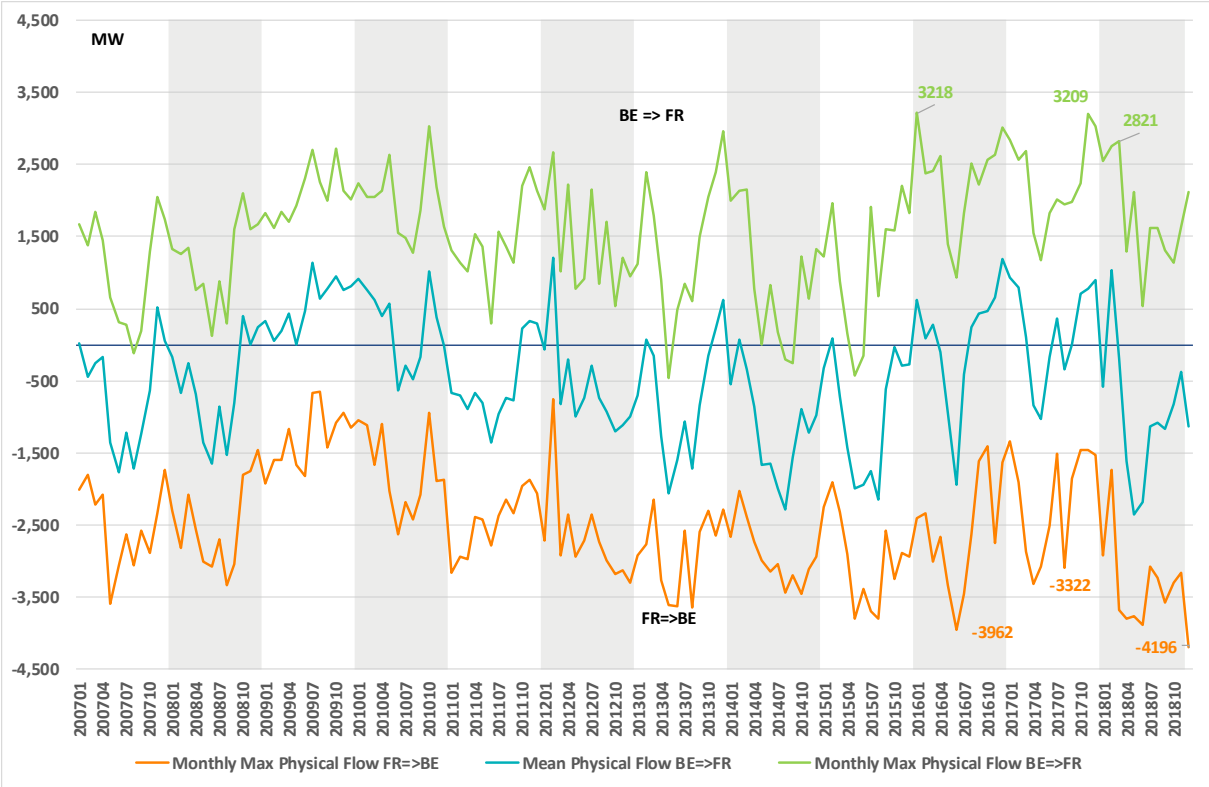


Figure 53: Physical flows on the Northern border (top) and the Southern border (bottom). Positive values indicate physical flows in the North-to-South direction.

4.3.8. Evaluation of CWE day-ahead Flow Based Market Coupling

77. CWE day-ahead FBMC went live in May 2015, thereby replacing the former ATC-method for coupling the day-ahead markets in the CWE region. Contrary to ATC, FBMC makes it possible to optimize the zonal net positions of the relevant bidding zones simultaneously, based on an optimization algorithm to maximize CWE social welfare while respecting network constraints. CWE FBMC makes it possible to be far less conservative than the ATC-method. This potentially allows a more efficient use and allocation of the existing network capacity.

78. In 2018, CWE FBMC performed notably better than in the previous 2 years in terms of maximum and average CWE cross-zonal exchanges. In December 2018, the combination of long-term and day-ahead cross-zonal exchanges in the CWE region reached 10,813 MW, i.e. 13% more than the maximum of 9,536 MW reached in October 2017, 22% more than the maximum of 8,829 MW reached in 2016 and even 54% more than the maximum of 7,023 MW reached in 2012 with ATC (Figure 54). Compared to ATC, however, CWE FBMC still results in lower minimal exchanges. While the minimum CWE cross-zonal exchanges during congested hours amounted to 2,348 MW before CWE FBMC implementation, it went down to 1,456 MW with FBMC in 2017. In 2018, the lowest value of CWE exchanges recorded during congested hours amounted to 1,620 MW (Figure 54).

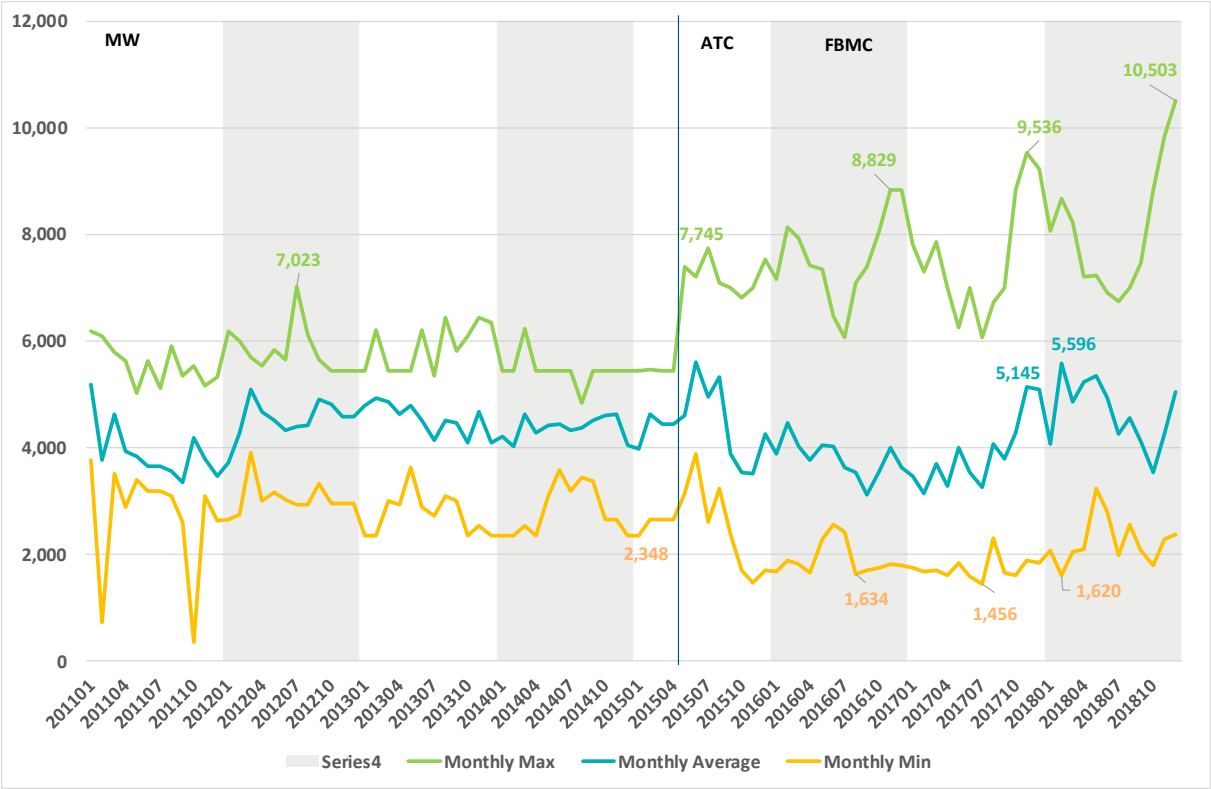


Figure 54: Maximum, average and minimum monthly values of CWE cross-border volume (day-ahead + long term) during congested hours for 2011 – 2017. The vertical line indicates the start of FBMC for day-ahead market coupling.
Sources: CWE TSOs, CREG

79. In annual terms, the yearly averaged cross-zonal exchanges in the CWE region reached 4,590 MW i.e. 20% more than the 3,736 MW yearly average achieved in 2017. The yearly averaged cross-zonal exchange during congested hours reached 4,684 MW, an increase of 17% compared to 4,018 MW in 2017. Based on these indicators, 2018 outperformed all previous years (see Figure 56). The monthly averaged CWE cross-zonal exchanges are shown in Figure 55, together with the average net positions of the different bidding zones.

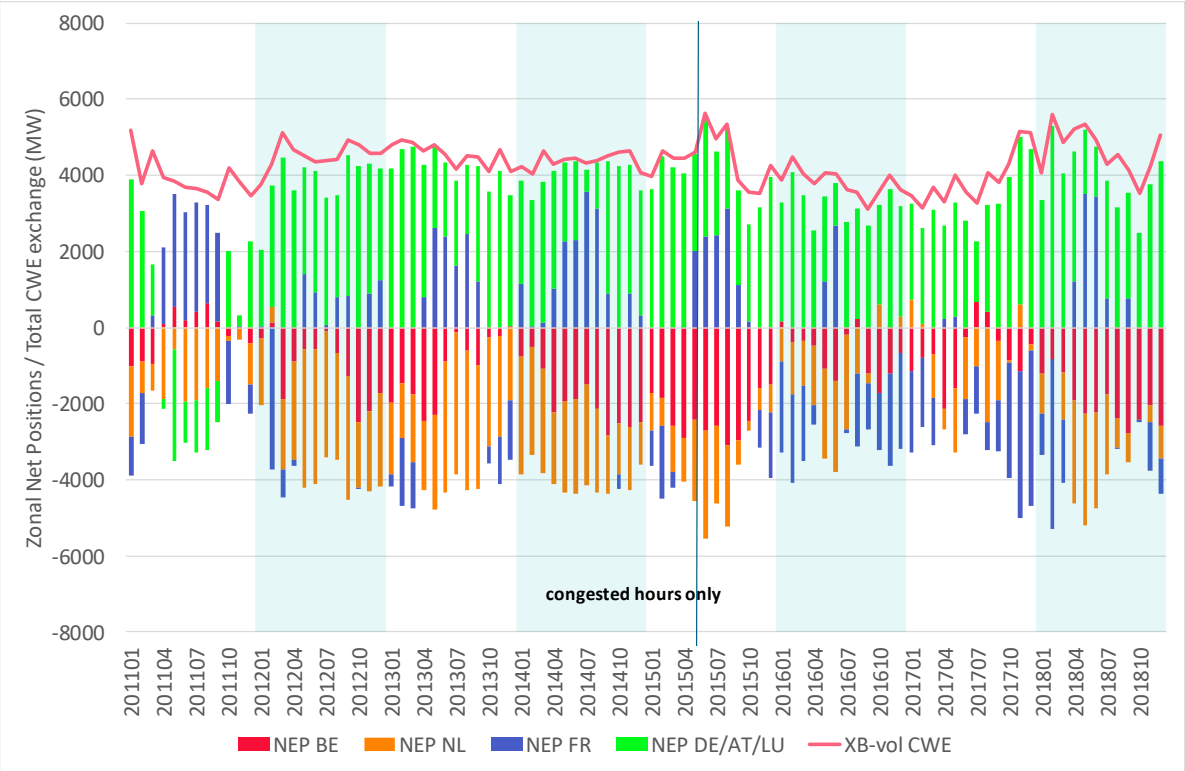


Figure 55: Monthly averaged Zonal Net Positions and CWE cross-zonal exchanges in day-ahead, including long term nominations, before and after the introduction of FBMC on 21 May 2015. By way of comparison, the net positions of the DE/LU and AT bidding zones after the DE/AT/LU bidding zone split on 1 October 2019, are lumped together.

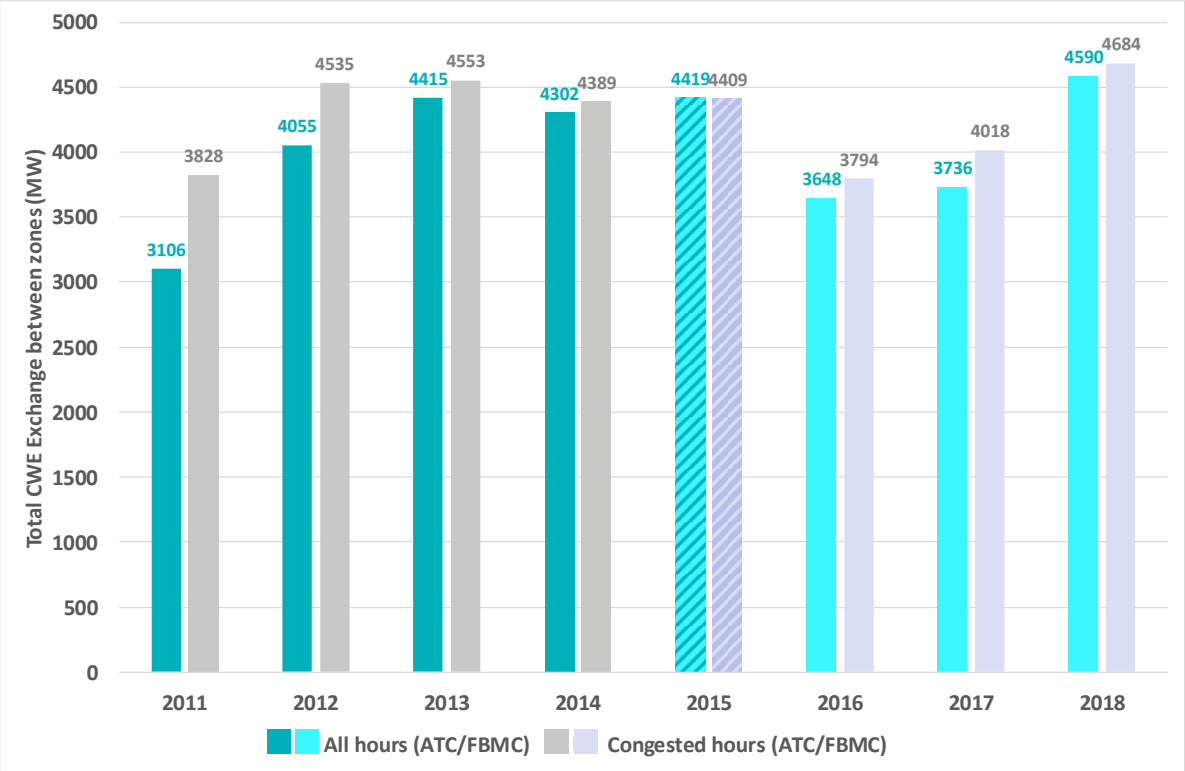


Figure 56: Yearly averaged day-ahead cross-zonal exchange in the CWE-region, including long-term nominations. The blue and gray bars indicate, respectively, the evaluated results over all hours and over congested hours only. The darker bars show the results with ATC, the lighter ones the results with FBMC. By way of comparison, exchanges between the DE/LU and AT bidding zones after 1 October 2018 are not included in the figures. As such, the net positions of the DE/LU and AT bidding zones after the DE/AT/LU bidding zone split on 1 October 2019, are lumped together.

80. The results of CWE FBMC in 2018 were in contrast with its initial years of implementation, from 2015 to 2017, when CWE FBMC was clearly underperforming due to the presence of highly loaded internal network constraints defining the flow-based domain. In the CREG study 1687, the CREG identified the role of collective and individual TSO discretionary actions which led to the observed situation with cross-zonal exchanges being on average below the values promised by the parallel runs – and even below ATC-values. As discussed in this study, in a majority of hours the capacities offered in the day-ahead market often merely corresponded to the capacities determined by the long-term transmission rights, which in turn were only guaranteed thanks to the application of the LTA-inclusion patch (see also Section 4.2 in the CREG Market Monitoring Report 2016). In essence, CREG concluded that the risks for non-efficiency and discrimination identified in the CREG Decision 1410 of April 2015 had materialized.

81. The recovery of CWE FBMC started in October 2017 thanks to a reduction of the size and number of network constraints. During winter 2017-2018, CWE exchanges were significantly higher than in winter 2015-2016 and winter 2016-2017 thanks to - among other things - the increase in Fmax-values of frequently congested internal critical branches with the application of seasonal ratings and/or DLR, and thanks to lower loop flows. Further performance improvement was obtained during 2018 by the 20% minRAM measure implemented at the end of April 2018, the introduction of the DE/AT-LU bidding zone split in October 2018, the removal of the French and DE/AT/LU export limits and the increase of the Belgian import limit. Those structural changes were included in the updated CWE FBMC approval package submitted by CWE TSOs in June 2018 in view of the inclusion of the DE/LU-AT bidding zone border, and approved by the CREG in its Decision 1814 of August 2018. Discussions on the impact and concrete implementation of the Clean Energy Package on the CWE FBMC methodology are still ongoing.

4.3.9. Evaluation of CWE day-ahead market coupling results

82. Average day-ahead market prices in 2018 increased in the entire CWE region. In Belgium, the Netherlands and the German bidding zone, prices went up by roughly 10 €/MWh and in France by 5 €/MWh (Table 24). Compared to 2017, the number of hours with full price convergence and price spread remained almost the same. Full price convergence was reached in 36% of hours, with an average CWE DAM price of 52.7 €/MWh (Table 25). The average CWE price spread during congested hours was 21.0 €/MWh, with prices typically being the highest in Belgium and lowest in the German bidding zone (Table 26). Average CWE exchange during congested hours was 4,684 MW, which is the highest value since the start of the market coupling and significantly higher than the 3,794 MW minimum recorded in 2016.

As discussed in the market monitoring report of 2017, the observed reduction in CWE day-ahead exchanges in 2016 and 2017 resulted from inefficiencies in the CWE FBMC implementation linked to the set of network constraints defining the flow-based domain. Similarly, the observed improvement from October 2017 and continued in 2018 is explained by a couple of short-term and medium-term measures taken to eliminate a range of network constraints from the flow-based system. It could be argued that the results in 2016 and in 2017 were also affected by the CWE market conditions, with France having been a net importer, in contrast to previous years. However, the last 3 months of 2017 do not confirm this assumption. From October to December 2017, CWE cross-zonal exchanges reached pre-FBMC values (Figure 55) despite France importing 3,063 MW to 3,984 MW from the CWE region during congested hours, the highest monthly net import values until then. In February 2018, France imported even more from the CWE region, namely 4,005 MW.

Year	Average Day-Ahead Market Clearing Price (€/MWh) *averaged over all hours*						Average Day-Ahead Cross-zonal Exchanges and Net Positions incl. Long Term Nominations (MW)				
	Conv (% h)	CWE price spread	BE	NL	FR	DE/LU	CWE XB-exch	BE	NL	FR	DE/LU +AT
2011	69%	4.3	48.9	52.0	48.9	51.1	3,106	-255	-967	884	338
2012	50%	8.1	47.0	48.0	46.9	42.6	4,055	-1,049	-2,019	326	2,743
2013	16%	16.3	47.4	51.9	43.2	37.8	4,415	-1,109	-2,399	361	3,148
2014	21%	10.9	40.7	41.1	34.5	32.6	4,302	-1,929	-2,015	1,240	2,704
2015	21%	14.2	44.6	40.0	38.3	31.6	4,419	-2,392	-1,289	656	3,025
2016	38%	10.2	36.6	32.2	36.7	29.0	3,648	-728	-1,032	-736	2,496
2017	37%	14.3	44.5	39.3	45.0	34.2	3,736	-736	-663	-1,300	2,699
2018	**36%**	**13.3**	**55.3**	**52.5**	**50.2**	**44.7**	**4,590**	**-2,019**	**-1,338**	**534**	**3,701**
Average	36%	11.5	45.6	44.6	43.0	38.0	4,033	-1,274	-1,465	242	2,606

Table 24: Annual average results for the CWE day-ahead market clearing, evaluated over all hours[25].

Year	Average Day-Ahead Market Clearing Price (€/MWh) *during hours with price convergence*						Average Day-Ahead Cross-zonal Exchanges and Net Positions incl. Long Term Nominations (MW)				
	% hours	CWE price spread	BE	NL	FR	DE/LU	CWE XB-exch	BE	NL	FR	DE/LU +AT
2011	69%	0.0	53.7	53.7	53.7	53.7	2,775	-378	-790	624	544
2012	50%	0.0	47.3	47.3	47.3	47.3	3,570	-1,002	-1,821	653	2,171
2013	16%	0.0	57.2	57.2	57.2	57.1	3,701	-1,092	-1,512	-53	2,658
2014	21%	0.1	43.1	43.1	43.1	43.1	3,975	-1,857	-1,675	922	2,611
2015	21%	0.0	38.3	38.2	38.2	38.2	4,457	-2,407	-1,378	1,503	2,282
2016	38%	0.1	28.9	28.9	28.9	28.8	3,414	-638	-1,355	107	1,885
2017	37%	0.0	37.4	37.4	37.4	37.3	3,252	-575	-1,104	7	1,672
2018	**36%**	**0.1**	**52.7**	**52.7**	**52.7**	**52.7**	**4,425**	**-2,090**	**-1,363**	**1,201**	**2,858**
Average	36%	0.0	45.4	45.4	45.4	45.3	3,529	-1,057	-1,304	601	1,837

Table 25: Annual average results for the CWE day-ahead market clearing, evaluated over all non-congested hours[25].

Year	Average Day-Ahead Market Clearing Price (€/MWh) *during congested hours*						Average Day-Ahead Cross-zonal Exchanges and Net Positions incl. Long Term Nominations (MW)				
	% hours	CWE price spread	BE	NL	FR	DE/LU	CWE XB-exch	BE	NL	FR	DE/LU +AT
2011	31%	13.7	38.6	48.3	38.5	45.5	3,828	14	-1,352	1,448	-109
2012	50%	16.1	46.7	48.7	46.6	38.0	4,535	-1,096	-2,215	3	3,308
2013	84%	19.5	45.6	50.9	40.5	34.0	4,553	-1,113	-2,571	441	3,243
2014	79%	13.7	40.1	40.6	32.2	29.9	4,389	-1,948	-2,105	1,325	2,729
2015	79%	18.0	46.3	40.4	38.4	29.8	4,409	-2,389	-1,265	429	3,224
2016	62%	16.5	41.5	34.3	41.7	29.1	3,794	-785	-830	-1,263	2,877
2017	63%	22.6	48.6	40.4	49.4	32.4	4,018	-830	-407	-2,060	3,296
2018	**64%**	**21.0**	**56.7**	**52.4**	**48.8**	**40.1**	**4,684**	**-1,978**	**-1,323**	**151**	**4,185**
Average	64%	17.9	45.8	44.2	41.7	33.8	4,317	-1,396	-1,555	39	3,041

Table 26: Annual average results for the CWE day-ahead market clearing, evaluated over all congested hours[25].

83. The number of hours with full price convergence in the CWE region in 2018 remained practically the same as in 2017. Nevertheless, differences are apparent on a monthly basis. Price differences

[25] The DAM prices shown for the DE/LU bidding zone correspond to those of the DE/AT/LU bidding zone before 1 October 2018, and to those of the DE/LU bidding zone after 1 October. The DAM prices for the Austrian bidding zone (AT) after 1 October 2018 are not shown. The net positions shown for DE/LU+AT correspond to the DE/AT/LU bidding zone net position before 1 October 2018, and to the sum of the DE/LU and the AT net position after 1 October 2018.

during the first half of 2018 were in general higher, while price differentials in October to December 2018 were significantly lower than in the same period previous years (Figure 57).

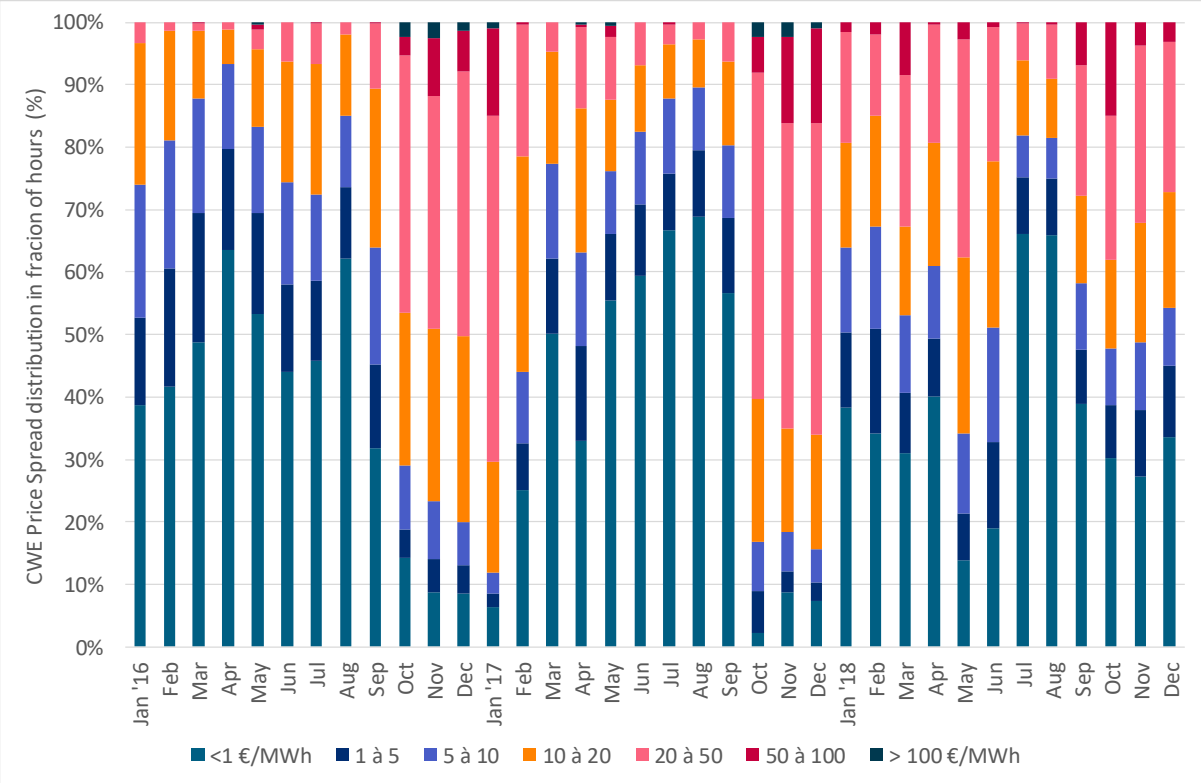


Figure 57: Distribution of CWE price spreads as a fraction of hours (%)

4.3.10. Evaluation of network constraints

84. CWE FBMC makes it possible to know for each congested hour which were the active network constraint(s) or Critical Network Element under Contingency ('CNEC'). Current CWE FBMC methodology makes it possible to manage congestion on both cross-zonal ('XB CNEC') and internal network elements ('INT CNEC'). Moreover, some CWE TSOs also impose explicit import and export limitations or so-called external constraints ('EC'). Table 27 gives an overview of the occurrence of each category of network constraints for 2018. Internal network elements contributed to 37% of all active constraints with an average RAM on 32%. Cross-border network elements, including PSTs, contributed to 55% of all active constraints with an average RAM of roughly 50%. External constraints accounted for 9% of active constraints.

85. The figures show that the occurrence of active constraints on internal network elements with very low PTDF and very low RAM decreased compared to 2016 and 2017, while the occurrence of active constraints on cross-zonal network elements with higher PTDF increased. This is explained by the implemented measures (application of winter limits or Dynamic Line Rating and introduction of 20% minRAM), which caused the average RAM on the most congested internal lines to go up and the congestion to move towards network elements with higher PTDF-values. With 37% occurrence, however, the number of active constraints on internal network elements remains very high. With an average RAM of only 32%, their impact remains high as well, with an average shadow price of 133 €/MW which may go up to 2,083 €/MW. Active constraints on cross-zonal network elements (cross-zonal lines and PSTs) have higher RAM-values on average and their associated shadow price is on average lower (105 €/MW). Active external constraints were only triggered at relatively high volumes of CWE cross-zonal exchanges, hence the relatively low associated shadow price (8 €/MW).

	Occurrence 2018		max PTDF (%)			RAM (% Fmax)			Shadow price (€/MW)		
Type of constraint ('CBCO')	Hours	%	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max
Internal line (INT)	2788	37%	15%	0%	40%	32%	2%	162%	133	0.1	2083
Cross-border line (XB)	2920	39%	21%	0%	43%	53%	9%	134%	105	0.0	1190
Phase Shift Transformer (PST)	1185	16%	29%	5%	50%	50%	8%	118%	69	0.0	833
External constraint (EC)	647	9%	100%	100%	100%	100%	98%	100%	8	0.0	58
Total	7540	100%	27%	0%	100%	49%	2%	162%	101	0.0	2083

Table 27: Overview of active network constraints in 2018, evaluated per type.

86. The zone-to-zone PTDF values are typically lower for internal lines than for cross-zonal network elements. Zone-to-zone PTDFs are computed by CWE TSOs for each individual element and each individual hour, and express the expected impact of a zone-to-zone commercial exchange on the physical loading of that line.

87. The RAM values are typically lower on internal lines than on cross-zonal lines. The RAM represents the capacity available on a network element for cross-zonal exchange. Because of preloading of the lines by domestic exchanges, included as reference flows (Fref) with priority grid access, the RAM currently falls well below the thermal line capacity (Fmax). In 2018, RAM values on internal lines, expressed relatively to their corresponding Fmax-value, were 39% on average, which is well above the 16% average observed in 2017 but nevertheless still low. For cross-zonal lines and PSTs the average RAM amounted to 53% and 50% respectively (Table 27), which is only a slight increase compared to the averages of 39% and 49% obtained in 2017.

88. The shadow price of congestion on internal lines is significantly higher than for congestion on cross-border elements. The shadow price represents the increase in CWE total welfare (€) for a unit increase of the available capacity on the congested element (MW) and depends on the specific market situation and on the multiplicative effect of a line. The latter represents the extra volume of cross-zonal exchange enabled by an extra unit of available capacity on that line. The smaller the zone-to-zone PTDF, the higher the multiplicative effect. High shadow prices reflect high opportunity costs of the congestion and typically arise when cross-zonal exchanges are heavily limited. In 2018, the shadow price of congestion on internal lines was 133 €/MW on average, with maximums up to 2,083 €/MW. In 2017, before the implementation of the 20% minRAM threshold, the shadow price associated with active internal CNECs was even higher: 208 €/MW on average, with maximums up to 2521 €/MW. For congestion on cross-zonal lines and PSTs, shadow costs were respectively 105 €/MW and 69 €/MW compared to 89 €/MW and 76 €/MW in 2017. The average shadow cost of external constraints, being triggered at larger volumes of cross-zonal exchanges, was 8 €/MW compared to 10 €/MW in 2017.

89. Table 28 lists the 25 most frequently active network constraints for 2018. The average values for the max PTDF, Fmax, RAM and FRM are shown, evaluated for the hours when the considered network element was congested. The last column indicates the policy for determining Fmax. The analysis at the individual network element level provides insight into the reasons why a specific network element was congested. Consider the following examples:

- The CNEC Ens-Lelystad (NL-NENS NLLS), internal to the Dutch bidding zone, was the most frequently active constraint in 2018. It has a relatively high zone-to-zone PTDF of 15% but a relatively low RAM as well, only 26% of Fmax on average. The RAM on this internal line is low because of reference flows in the basecase resulting from internal exchanges, loop flows and transit flows from non-CWE regions. Transit flows from non-CWE regions, such as e.g. exchanges over the HVDC-connectors Britned and Nordned within the Channel or Nordic region, have priority access to exchanges in the CWE region. This problem can be alleviated by the implementation of advanced hybrid coupling or a full merging of capacity calculation regions,

such that the exchanges can effectively enter into competition for gaining access to scarce network capacity. Note that Tennet Netherlands did not apply seasonal line ratings or Dynamic Line Rating (DLR) for determining Fmax on its CNECs[26].

- The CNEC XDI_ME, the interconnector between Germany and the north of the Netherlands, and ranked second in terms of occurrence, had only 45% RAM on average. This interconnector has a relatively small Fmax, relatively high FRM (20% of Fmax) and high loop flows (43% of Fmax). Tennet Germany (D2) did not apply seasonal line ratings or DLR for determining Fmax on its CNECs.
- The CNEC PST Zandvliet, located on the Belgian northern border, has been one of the most frequently congested network element as well, having one of the largest zone-to-zone PTDF of the list (35% PTDF). Its average RAM of 53% can be considered low for a cross-zonal network element. In the case of PST Zandvliet, this is partially due to the FRM value of 19% of the average Fmax of 1,534 MW. The remaining 28% of Fmax is used by loop flows. Similar observations hold for the Belgian internal line Doel-Zandvliet, directly connected to the PST Zandvliet.
- The CNEC BE-XAV_AV, the interconnector between Belgium and France, was also often congested. However, unlike the previous three examples, this CNEC with high average zone-to-zone PTDF (31%) has a high RAM on average (71%) when congested. Moreover, DLR is applied for determining the Fmax. The high occurrence of this kind of CNECs as active constraints in the CWE FBMC is perfectly legitimate.
- In contrast to previous years, internal lines with small PTDF inside the Amprion region, such as D7HANE_DGRON, D7BE_GU and D7KNAP DSECH were constraining far less often. This evolution is explained by the fact that Amprion applied seasonal line ratings and DLR at the end of 2017, and by the implementation of the 20% minRAM measure since April 2018.

[26] Tennet Netherlands, TenneT Germany and Transnet BW started the implementation of dynamic line rating on some of their internal lines in February 2019, see www.jao.eu/news/messageboard/overview

Critical Branch	TSO	Type	Count (hours)	Average maxPTDF	Average Fmax (MW)	Average RAM (MW)	Average FRM (MW)	Average RAM (%Fmax)	Average FRM (%Fmax)	Average Shadow cost	Fmax policy
NL-NENS NLLS	NL	INT	1220	15%	1732	446	173	26%	10%	113	Fixed
D2-XDI_ME	D2	XB	956	18%	1053	475	211	45%	20%	126	Fixed
BE-PST ZANDV	BE	PST	660	35%	1534	812	256	53%	19%	57	Seasonal
DE_export	DE	EC	XB	100%	6582	6576	0	100%	0%	7	Variable
BE-XAV_AV	BE	XB	427	31%	1693	1208	199	72%	12%	46	DLR
D7-PST GRON	D7	PST	410	19%	1498	589	150	39%	10%	104	Seasonal
NL-XDI_ME	NL	XB	377	15%	1053	388	208	37%	20%	147	Fixed
BE-XVY_MB	BE	XB	196	34%	1542	964	191	62%	10%	72	DLR
NL_import	NL	EC	190	100%	4286	4286	0	100%	0%	9	Seasonal
D7-D7YPAF DOBZI S	D7	INT	164	19%	2069	480	177	23%	9%	91	Variable
NL-NLLS NDIM	NL	INT	153	14%	1732	370	173	21%	10%	131	Fixed
BE-XAU_M.	BE	XB	139	12%	479	395	66	82%	14%	186	DLR
BE-PST VANYK	BE	PST	138	32%	1527	949	194	62%	11%	42	Seasonal
D2-D2SIT DAHM	D2	INT	115	7%	431	279	40	65%	10%	153	Seasonal
BE-BMERCA BRODE+	BE	INT	115	21%	1604	635	188	40%	12%	71	DLR
D4-XLA_KU	D4	XB	114	10%	1609	471	175	29%	10%	129	Seasonal
D7-XSI_MB	D7	XB	109	26%	1805	1222	112	68%	6%	33	Seasonal
D7-XEN_VI	D7	XB	98	22%	1887	766	229	41%	12%	29	Seasonal
BE-BZANDV BDOEL	BE	INT	97	31%	1517	738	284	49%	20%	89	DLR
D7-D7HANE DGRON	D7	INT	87	9%	2074	207	130	10%	6%	254	DLR
D7-D7BE_GU	D7	INT	79	5%	1884	115	169	6%	9%	431	Fixed
D2-D2RED DMH	D2	INT	72	11%	1527	514	145	34%	10%	112	Fixed
D7-XRO_MB	D7	XB	72	21%	1787	643	104	36%	6%	83	Fixed
D7-D7KNAP DSECH	D7	INT	67	6%	2182	173	185	8%	8%	159	DLR

Table 28: Characteristic of Top 25 active constraints in the CWE FBMC in 2017, ranked by number of occurrences. The averages are calculated over the hours the specific network element was an active constraint.

90. The breakdown of Fmax into Fref, FRM and RAM is shown in Figure 58 and Figure 59 on an individual network element level for congested cross-zonal lines and internal lines respectively. Additionally, a new variable is shown, i.e. the Adjustment for minRAM or 'AMR'. As the name suggests, it represents an adjustment value, applied by CWE TSOs, to increase the RAM up to 20% of Fmax and beyond:

$$RAM = Fmax - Fref - FRM + FAV + AMR$$

The use of an AMR as adjustment variable is equivalent to a positive FAV, with the difference that an FAV does not serve a specific minimum RAM target and that an FAV is intended to represent the impact of complex remedial actions which cannot easily be included in the basecase. In other words, the application of an AMR does not necessarily represent a set of remedial actions to free up commercial capacity. The motivation provided by CWE TSOs for using an AMR to reach the minRAM target on each CNEC is that the remedial actions will be defined once the results of the day-ahead market coupling are known. This approach differs from the initial approach proposed by the CREG in 2017 in which the capacity for the market is made available through remedial actions taken in the basecase, and more specifically actions to relieve internal congestion and to reduce loop flows. The motivation for the latter approach is that it makes it possible to improve the accuracy of the load forecast used in the capacity calculation, which the CREG deems necessary for the sake of grid security management.

Figure 58: Use of the Thermal Line Capacity (Fmax, vertical axis) for Reference Flows (Fref), Flow Reliability Margins (FRM) and commercial flows from CWE DA cross-zonal exchange (equal to the RAM) for cross-zonal elements when congested, annual averages for 2018. Since the introduction of the 20% minRAM measure at the end of April 2018, CWE TSOs also apply an Adjustment for minRAM (AMR) to ensure that the RAM is equal or higher than 20% of Fmax.

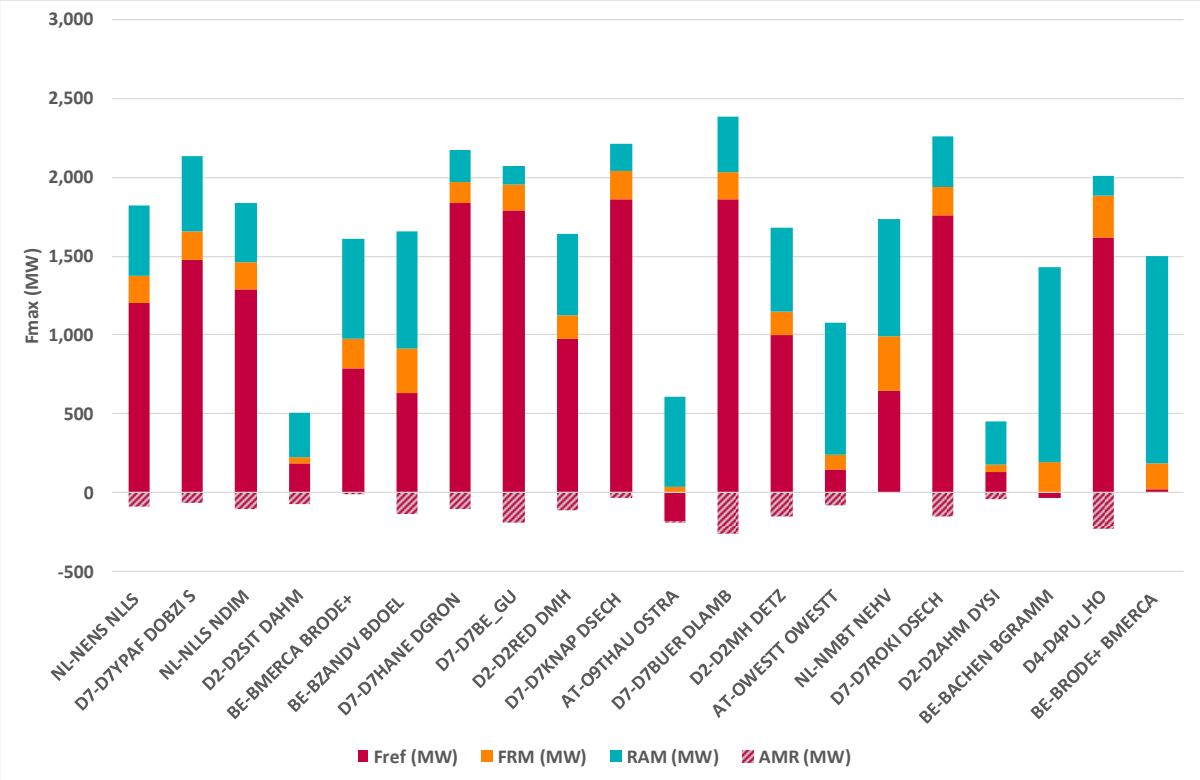


Figure 59: Use of the Thermal Line Capacity (Fmax, vertical axis) for Reference Flows (Fref), Flow Reliability Margins (FRM) and commercial flows from CWE DA cross-zonal exchange (equal to the RAM) for internal lines when congested, annual average for 2018. Since the introduction of the 20% minRAM measure at the end of April 2018, CWE TSOs also apply an Adjustment for minRAM (AMR) to ensure that the RAM is equal or higher than 20% of Fmax.

91. Most of the congested network elements in 2017 were located in the network of Elia and Tennet Netherlands (both about 28% of cases) (Figure 60). In comparison to 2016 and 2017, the contribution of network elements located in Amprion significantly decreased while the contribution of CNECs located in the Tennet Germany network remained similar and the contribution of CNECs located in the Tennet Netherlands network increased. RAM-values on all active CNECs were significantly higher than previous years, except for those in the Dutch bidding zone (Figure 62). The histogram of the occurrence of active CNECs by relative RAM (%Fmax) per TSO is shown in Figure 62.

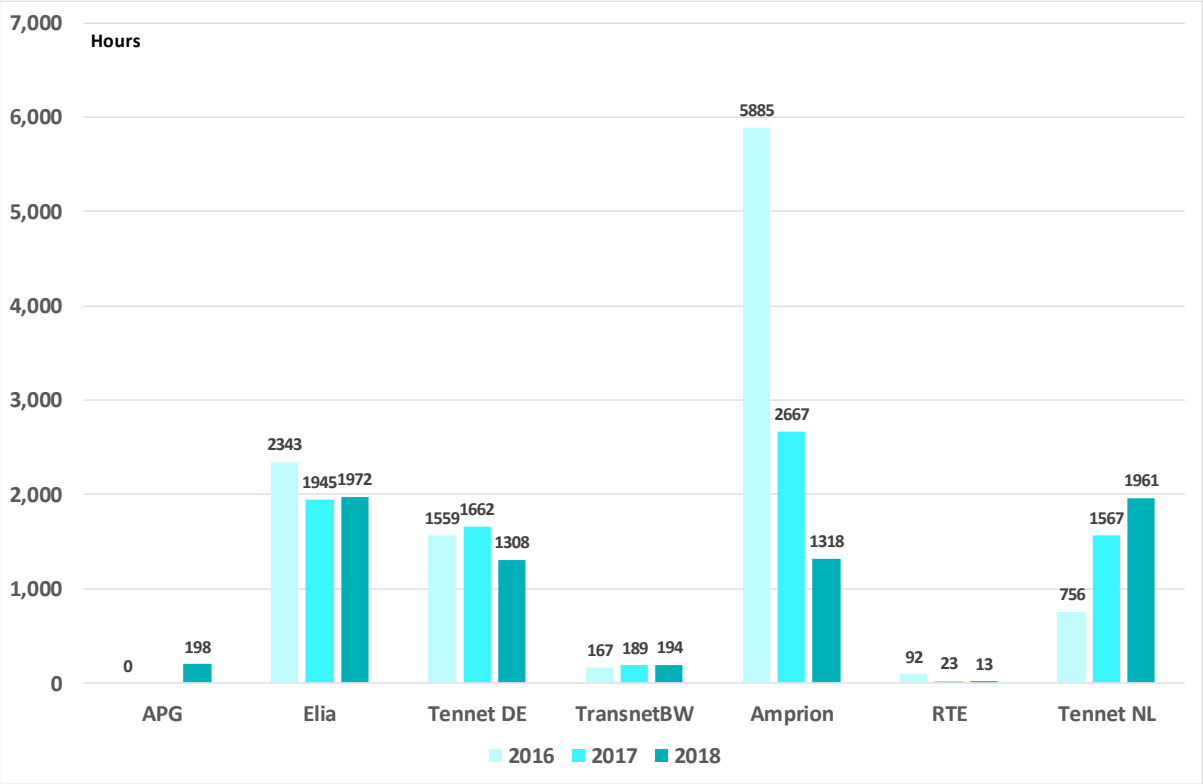


Figure 60: Locational distribution of the congested network elements per TSO in 2016, 2017 and 2018

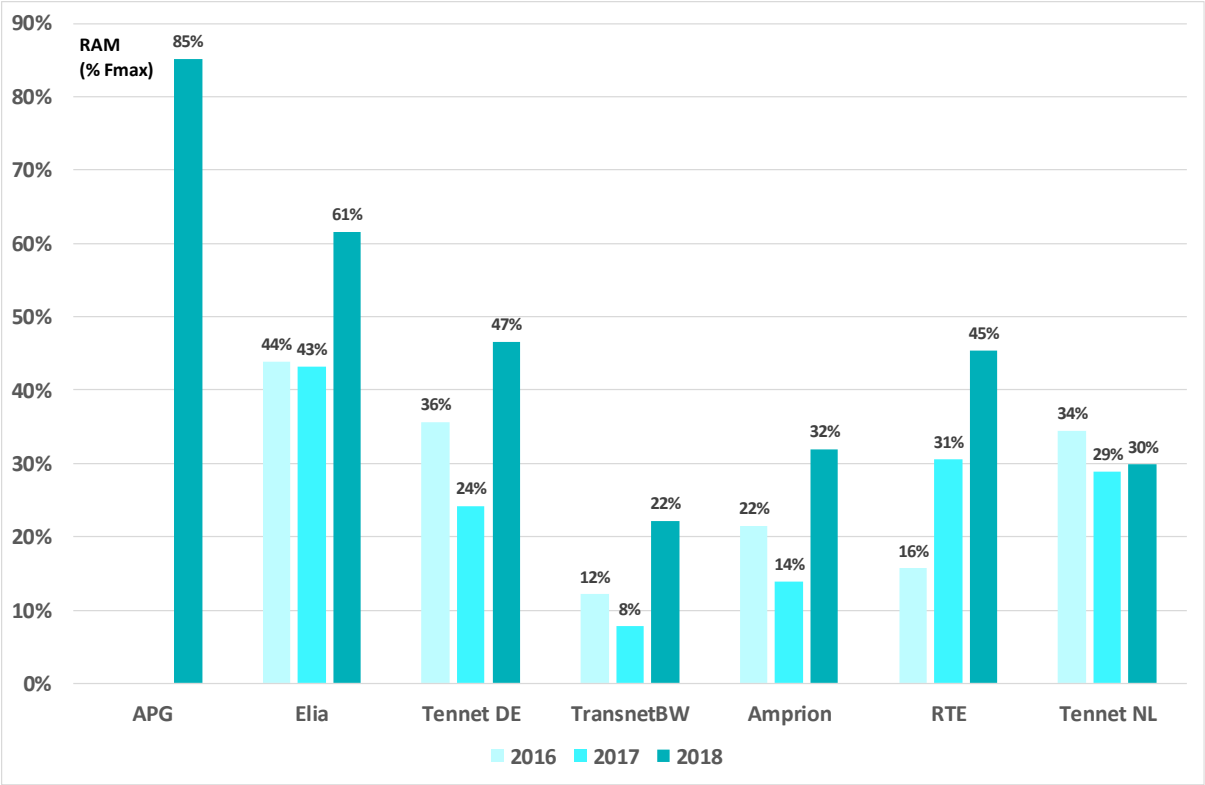


Figure 61: Histogram of the occurrence of congestion by RAM (%Fmax) per TS0 in 2016, 2017 and 2018

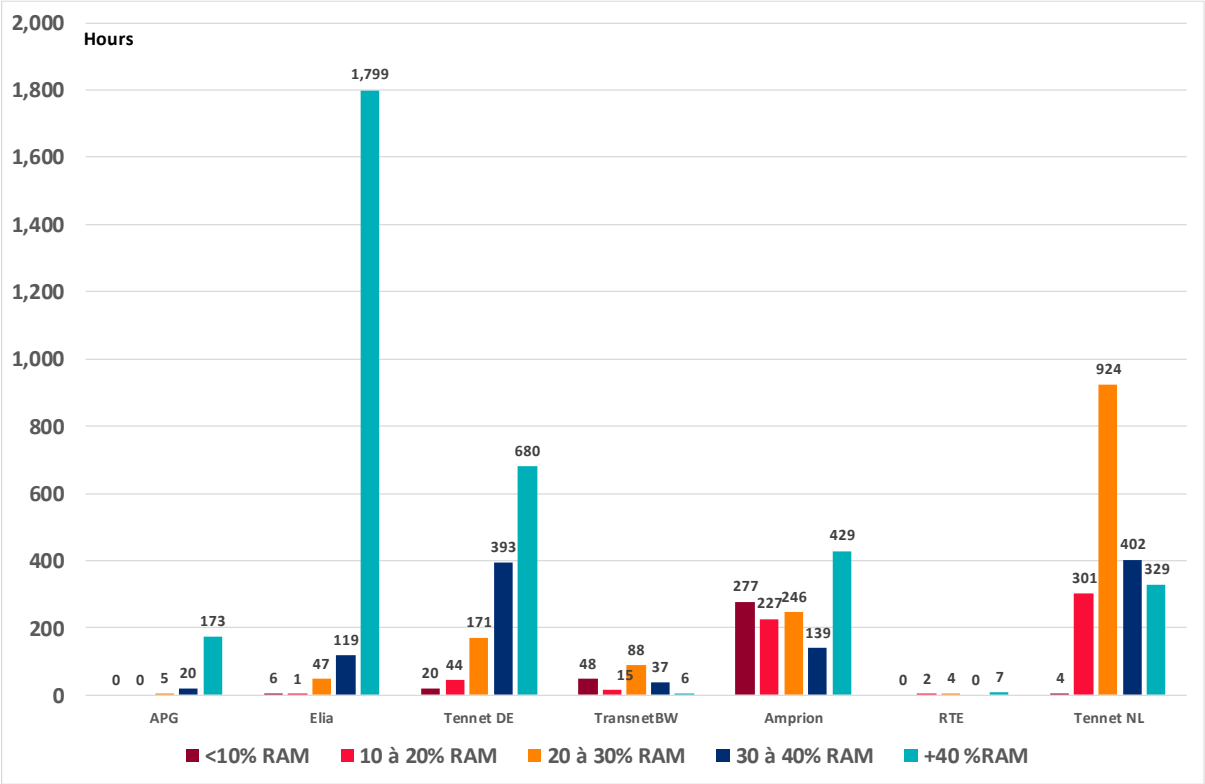


Figure 62: Histogram of the occurrence of congestion by RAM (%Fmax) per TS0 in 2018

	Occurrence 2018		max PTDF (%)			RAM (% Fmax)			Shadow price (€/MW)		
TSO	Hours	%	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max
APG	198	3%	12%	9%	20%	85%	25%	162%	152	0	804
Elia	1972	28%	30%	3%	50%	61%	5%	134%	68	0	882
Tennet DE	1308	19%	15%	0%	36%	47%	2%	115%	133	0	1021
TransnetBW	194	3%	9%	5%	10%	22%	4%	46%	191	1	964
Amprion	1318	19%	17%	0%	36%	32%	2%	98%	129	0	2083
RTE	13	0%	21%	10%	32%	45%	11%	73%	47	0	247
Tennet NL	1961	28%	16%	8%	40%	30%	10%	89%	117	0	1190
Total	6964	100%	20%	0%	50%	44%	2%	162%	111	0	2083

92. External constraints have limited cross-zonal exchange in 647 hours, or in 9% of hours in 2018. In 75% of cases, this was a German export constraint. Especially during the February and March, when CWE-cross-zonal exchanges were relatively high (see Figure 55), German exports were frequently limiting (334 hours). Since 1 October 2018, with the introduction of the DE/LU-AT bidding zone border, the German export constraint has been removed. The French export and import constraints had already been removed in 2017. Dutch import constraints have limited CWE cross-zonal exchange in up to 190 hours, especially from April to July. Belgium still applies import constraints, but Belgian import constraints have never been active since the launch of CWE FBMC. Elia adapted the external constraint value for import from 4,500 MW to 5,500 MW from 1 June 2018 onwards.

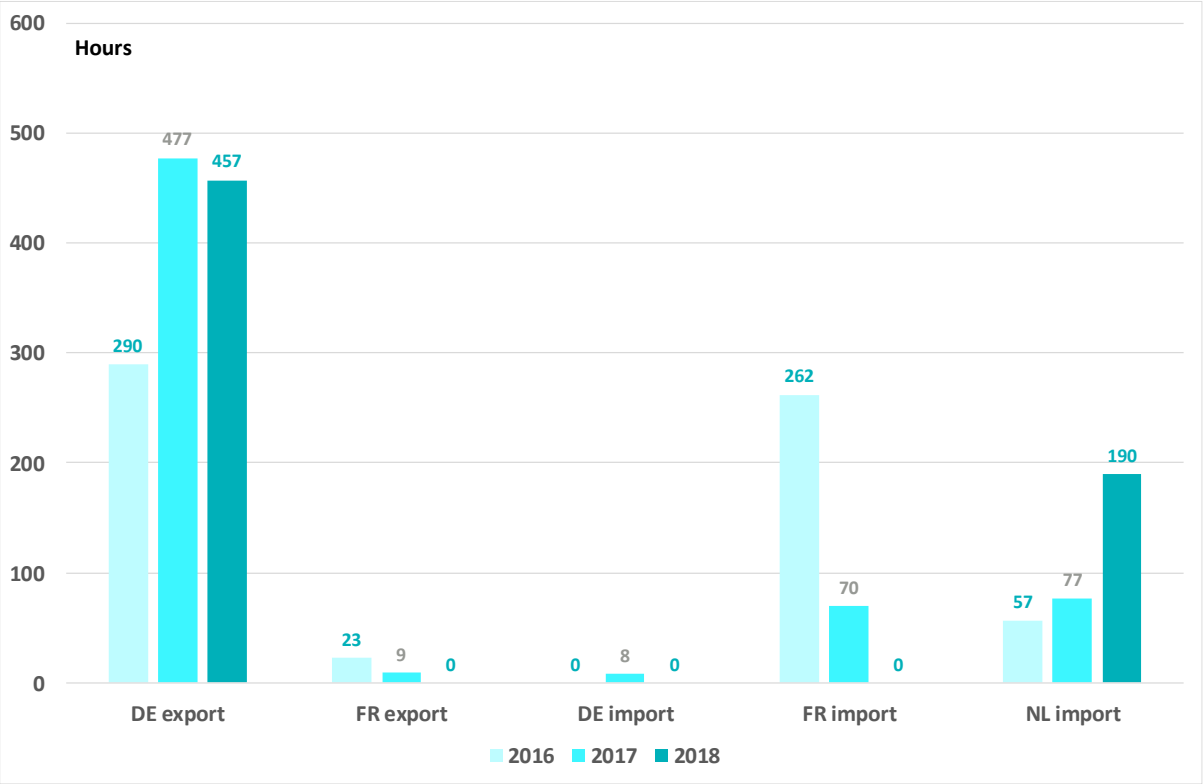


Figure 63: Number of hours an external constraint was limiting the CWE cross-zonal exchange in 2016, 2017 and 2018.

4.3.11. Congestion rents

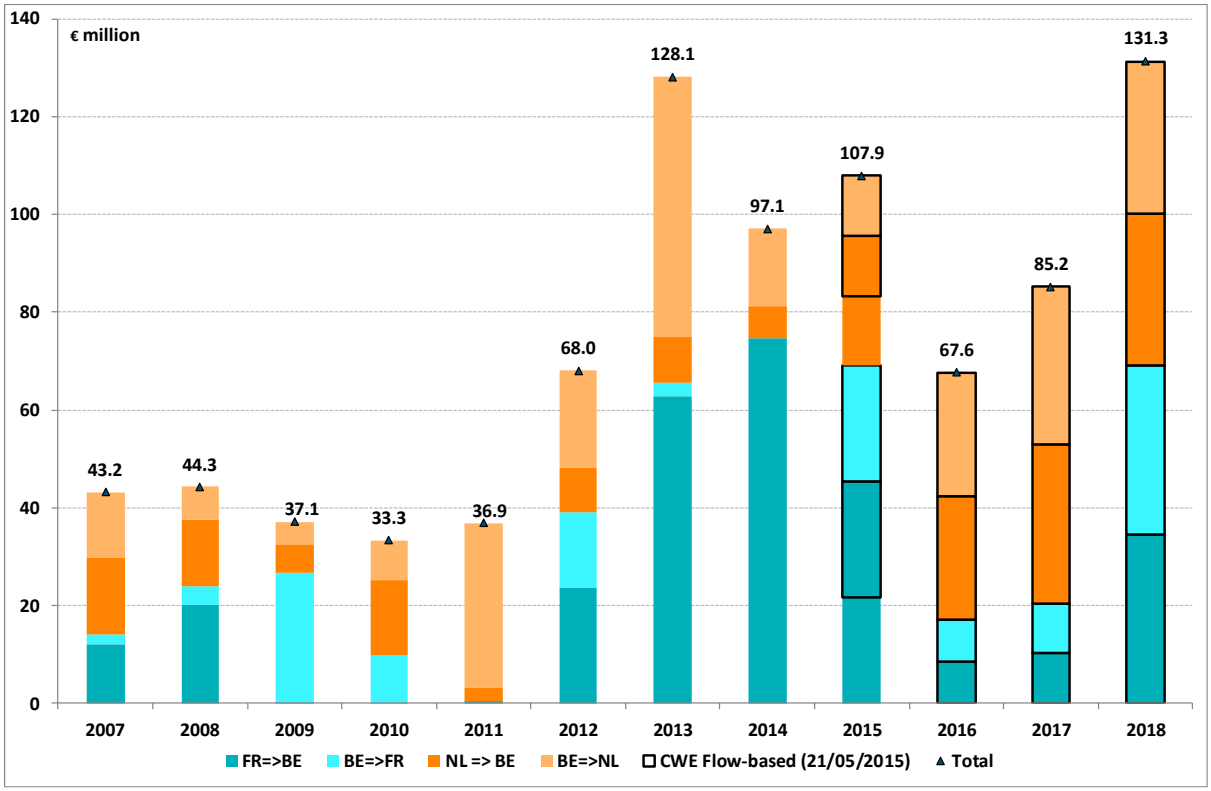


Figure 64: Congestion rents per border and per direction. For the years with FBMC, the values correspond to the total congestion income generated on the Belgian borders prior to resales. The values do not show how the income is distributed among long-term transmission rights holders on the one hand and the TSOs of the concerned bidding zones on the other.

93. With the ATC method, the calculation of the congestion rents was straightforward, based on the hourly nominated capacities and price difference on each border. With FBMC, the calculation is more complex since the output of FBMC are the zonal net positions, not the nominations on individual borders. Therefore, FBMC requires a post-processing step to determine the congestion rents.

94. In 2018, the congestion rents generated at the Belgian borders increased by more than 50% compared to 2017 and attained the highest level ever (Figure 64). Compared to 2016 and 2017, congestion rents at the southern border increased, reaching similar values as in 2013-2015. This increase is due to increased imports from France to Belgium and the Netherlands and to higher price spreads at the southern border. The congestion rents at the northern border remained high because of high commercial exchanges in both directions and sustained high price spreads.

	Average of absolute value of price spread (€/MWh)	
Year	**BE-NL**	**BE-FR**
2011	4.0	0.5
2012	2.7	2.8
2013	6.1	4.6
2014	2.2	6.2
2015	5.9	6.4
2016	6.1	2.6
2017	7.2	4.2
2018	6.3	5.6

Table 29: Annual average of absolute price spreads at the Belgian borders since 2011.

5. BALANCING

5.1. HISTORICAL BACKGROUND: SIGNIFICANT EVENTS

2012 Single marginal prices for imbalance tariffs were introduced. At the end of June, a virtual resource with 0 MW capacity was introduced. The objective is to activate the virtual unit at a price equal to €-100/MWh in periods where all resources for downward activation are activated but still additional decremental activations are needed. In October, Elia started participating in the International Grid Control Cooperation platform (IGCC) to optimise the balancing management of the system and optimize the quality of the frequency. Any imbalances are automatically offset if they are in opposite directions experienced by system operators. The advantage of this system is that it enables TSOs to avoid activating secondary reserves in opposite directions. Other IGCC participants are Amprion, 50Hertz, TransnetBW and TenneT DE (the four German transmission system operators), Energinet.dk (Denmark), CEPS (Czech Republic), Swissgrid (Switzerland), TenneT NL (The Netherlands), APG (Austria) and RTE (France).

2014 Asymmetrical products for R1 were introduced, thereby opening the R1 market to demand response. Additionally, monthly auctions for contracting a part of the R1 and R2 volumes were introduced. The R3 DP product was introduced. Finally, a special tariff for the hours where strategic reserve is activated was introduced: €3,000/MWh in case of shortage of injection bids to reach the clearing of the day-ahead market price and €4,500/MWh in case of structural shortage and technical trigger in intraday and real time.

2015 Monthly R1 and R2 auctions were extended to contract the whole volume of R1 and R2.

2016 Monthly auctions were introduced to contract a part of the R3 volumes, except for the R3 ICH product. In August, the market for R1 products was fully opened: any supplier is allowed to participate in all primary control services, irrespective of the connection point of the resource involved. Additionally in August, weekly auctions for the whole R1 and R2 volume to be contracted were organized. Elia and market participants received access to the Regional (AT-BE-DE-NL) Auctions Platform for R1, to purchase or sell R1 standard products (symmetrical R1 200 mHz).

2017 In February, the project '*BidLadder*' was finalised, permitting non-CIPU units to offer free bids for the delivery of tertiary reserves. In March Elia carried out a study concerning the extension of the existing secondary reserve market. Two extensions by the end of December were proposed: (i) to the intraday market for CIPU-units and (ii) to day-ahead and intraday for contracted non-CIPU units. In May a new contractual framework for the delivery of primary reserves was introduced. The energy sources that qualify for the delivery of primary reserves was extended to include sources with limited energy volumes such as batteries.

On 25 August the Official Journal of the European Commission published the system operation guideline. On 28 November the same Journal published guidelines on electricity balancing.

2018 As of 1 June, Transfer of Energy for balancing services for non-reserved mFRR from non-CIPU units connected to a quarterly meter is allowed. Approved on 24 May, Transfer of Energy reduces barriers to valorize flexibility services that can be provided by demand resources. From December onward, Transfer of Energy applied to contracted mFRR Standard and mFRR Flex products.

As of December, contracted mFRR reserves are no longer activated after non-contracted mFRR reserves irrespective of the price: a merit-order activation is introduced.

Following the unexpected prospect of only 1 nuclear power plant being available during October and part of November, and the prospect of a maximum of 2 nuclear power plants being operational until the end of the year, the CREG approved a new winter product to stimulate the participation of slow-starting units to the mFRR balancing energy market. The product serves two purposes: it increases market participation of units that could not participate before to the market and it allows insights on the existing flexibility in the electricity system.

On 18 December the CREG approved the common and harmonised rules and processes for the exchange and procurement of balancing capacity for frequency containment reserves (FCR). These processes increase competition and will lead to efficient pricing of FCR balancing capacity.

5.2. SPECIAL TOPIC: PROCUREMENT OF BALANCING CAPACITY

95. The cost of procuring the necessary capacity of FCR reserves in order to maintain secure system operation has more than halved in the past four years, from 22,1 MEUR to 9,4 MEUR (Table 30). The steepest cost decrease was observed in 2016, after the full opening of the FCR market to new entrants in Belgium (by shortening the contracting period to weekly instead of monthly) and abroad (by facilitating cross-zonal procurement of FCR capacity). Although the decrease in FCR capacity needs have played a role in the trend of cost decreases for FCR procurement, the main contributing element is the decrease of procurement costs in €/MW/h whose trend correlates more with the trend of overall FCR procurement cost decrease.

[k€]	FCR	aFRR	mFRR
2015	22.141	28.856	18.718
2016	11.714	33.551	24.619
2017	10.151	34.791	23.337
2018	9.391	43.214	71.909

[MW] capacity needs	FCR	aFRR	mFRR
2015	83	140	661
2016	68	140	770
2017	68	142	780
2018	81	139	830

[€/MW/h]	FCR	aFRR	mFRR
2015	30,5	23,5	3,2
2016	18,3	27,3	3,6
2017	17,0	28,0	3,4
2018	14,7	35,5	9,9

Table 30 – Procurement costs, capacity needs and normalised procurement costs for each of the reserve types procured in the LFC Area of Elia
Source: calculation CREG based on data received from Elia

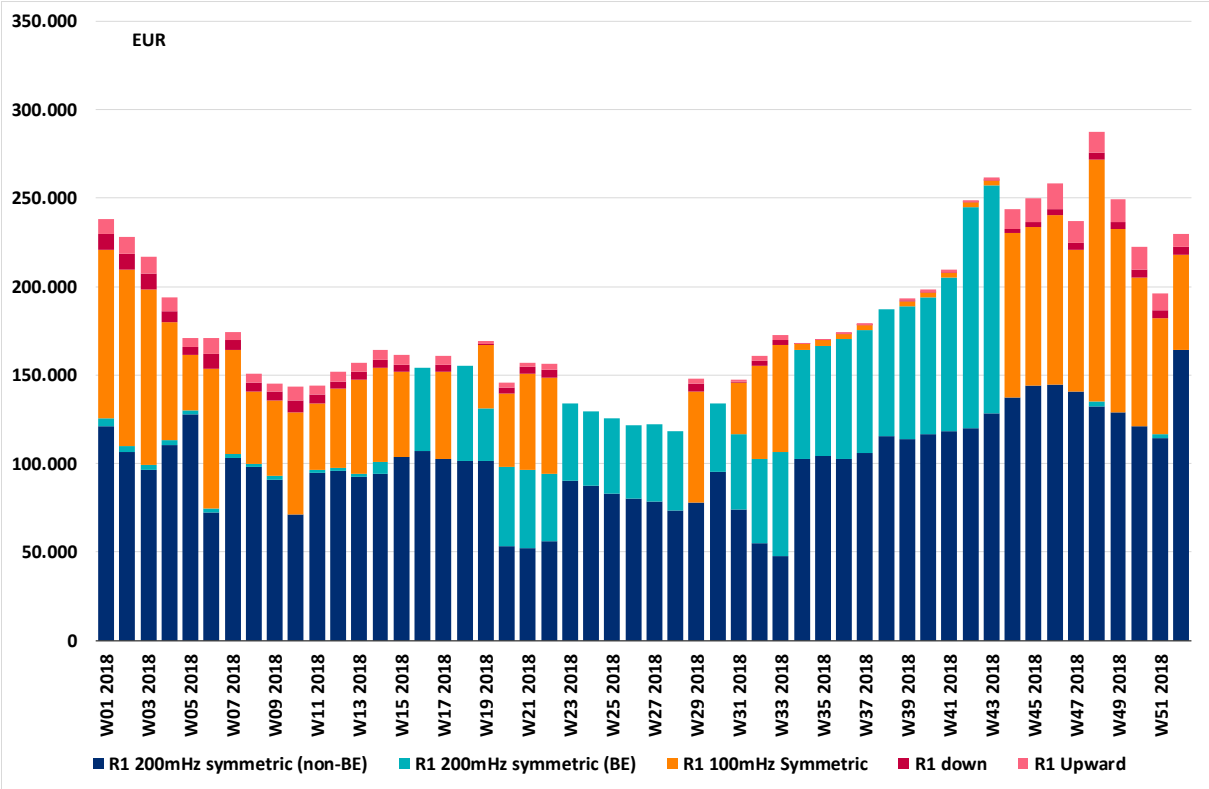


Figure 65 – FCR capacity procurement costs in 2018, per week and per product
Source: calculation CREG based on data received from Elia

96. In 2018, every weekly auction FCR capacity is partially procured from outside of Belgium (Figure 65). For the remaining FCR capacity needs, either the fully symmetric 200 mHz profile is procured or this symmetric profile is assembled from symmetric 100 mHz and asymmetric products ("R1 down" and "R1 Upward"). The figure illustrates that opening the market to market participants outside of Belgium is important to create sufficient levels of competition in the FCR procurement market processes. Given that the capacity of asymmetric products has to be equal to the capacity of 100 mHz symmetric products (otherwise it is not possible to assemble the symmetric 200 mHz profile), it can also be derived from the figure that asymmetric products cost much less than symmetric products. Therefore, the figure also illustrates the importance of opening up the market to facilitate the participation of market participants offering competitive asymmetric products.

97. The importance of opening the markets for the procurement of reserves to new entrants in Belgium and abroad is accentuated when analysing the trend of aFRR and mFRR procurement cost. Procurement costs for aFRR capacity has increased by 52% while the necessary aFRR capacity has remained more or less constant (Table 30). Procurement costs for mFRR capacity have increased by 380%. Although part of the increase in procurement costs is caused by increasing needs for mFRR capacity to maintain system security, the cost increase in €/MW/h is again the main contributing element, despite measures being taken in 2017 and 2018 to reduce barriers to entry for new market participants in Belgium.

98. The steepest increase of aFRR and mFRR procurement costs was observed in the year 2018. More precisely, the increase of aFRR and mFRR procurement costs was observed during the last quarter of the year, during the same period high day-ahead prices were observed (Figure 66 and Figure 67). As the aFRR and mFRR capacity is contracted prior to the day-ahead market, market participants tend to include opportunity costs in their prices for aFRR or mFRR capacity: the higher the day-ahead market prices, the higher the opportunity costs and the more expensive the procurement of aFRR and mFRR reserves becomes.

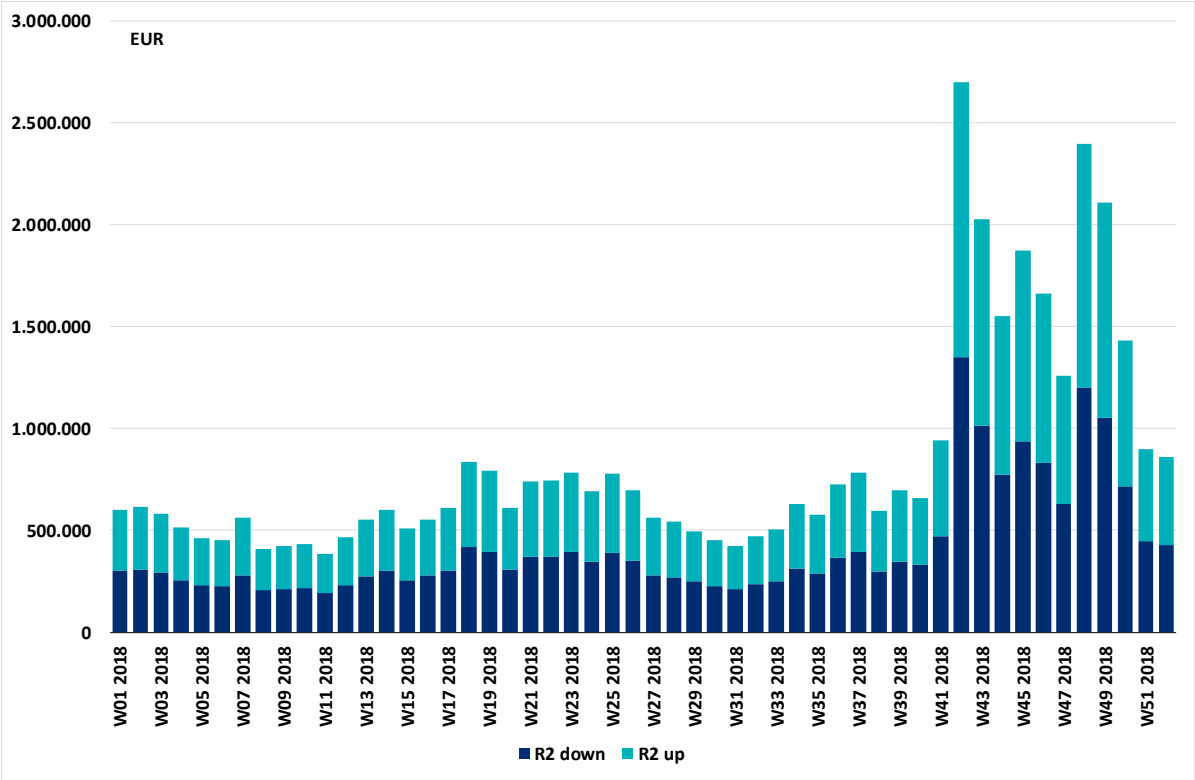


Figure 66 –aFRR capacity procurement cost in 2018, per week and per direction
Source: calculation CREG based on data received from Elia

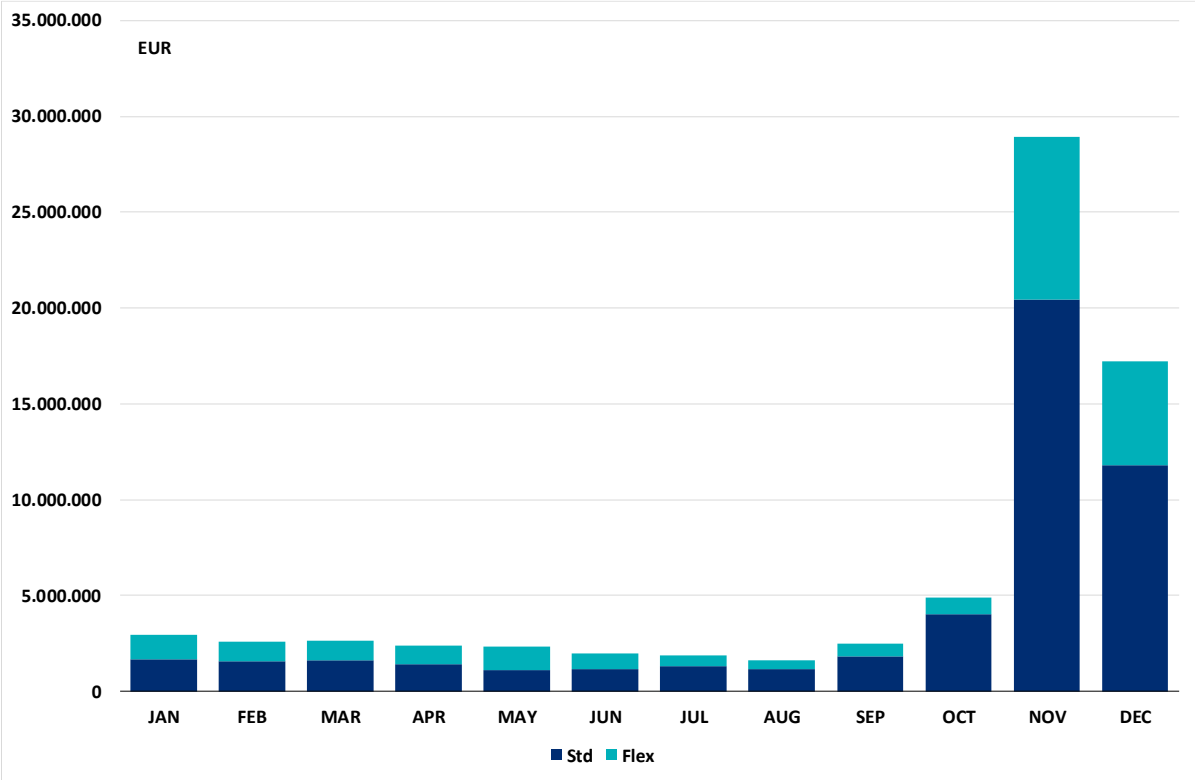


Figure 67 – mFRR procurement costs in 2018, per month and separated per product (standard vs. flex)
Source: calculation CREG based on data received from Elia

99. All markets in the CWE region saw an increase in day-ahead market prices in the fourth quarter of 2018. Whether the trend of increasing reserve capacity procuring costs is structural remains to be seen, but it is nevertheless clear that the increase observed in 2018 was not only caused by isolated events in Belgium, indicating that some structural causes are present.

5.3. STATISTICS

5.3.1. Contracted capacity

100. The federal grid code requires Elia to propose for the approval of the CREG (i) a methodology to be used to evaluate the volumes of primary, secondary and tertiary control reserves that contribute to guarantee the security, reliability and efficiency of the grid in the control zone, and (ii) the results of the evaluation. Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation, better known as the guideline on system operation or SOGL, requires Elia to propose a methodology according to articles 119 and 157.

101. By its decision 1631[27] of 6 July 2017, the CREG approved the proposal of Elia for the year 2018 (Table 31). Primary (FCR) and secondary (aFRR) control powers are contracted on a weekly basis. Primary volumes are locally contracted two weeks before the start of the delivery period by means of an auction. Additionally, Elia can procure part of its primary reserves regionally by an auction in which the TSOs of Germany, Austria, the Netherlands, Switzerland and Denmark participate. Two products of tertiary reserves (mFRR) are contracted by monthly auctions: mFRR Flex products are tailored to suit limited energy sources or industrial loads, while mFRR standard products apply for any other generation unit

Type	Contracted volume [MW]	Contracted period	Details on the contracting method
FCR	81	weekly	minimum 25 MW locally
aFRR	144	weekly	
mFRR	780	annually monthly	maximum 200 MW of R3 Flex ICH minimum 250 MW of R3 Standard undefined limits on R3 Flex

Table 31 - Types of reserves to be bought by Elia for 2018
Source: CREG

102. The cost associated with the contracting of reserves was relatively constant for the years 2015 to 2017 (Figure 68). The 35% drop in reservation costs from 2014 (delivery in 2015) and 2015 (delivery in 2016) is attributed to the introduction of short term auctions for the combined reservation of FCR and aFRR, which had a significant impact on the reserved capacity to provide aFRR (R2). Starting from January 2015, FCR and aFRR capacity was reserved monthly. Since August 2016, the contracting period became weekly. Contracting for FCR (primary reserves, R1) is at its least costly for a decade.

The reservation of the capacity required by R3 Flex and R3 Standard remained on an annual basis until 2016, when 70 MW were procured by monthly auctions. Since 2017 the full capacity required has been procured by monthly auctions. R3 Flex ICH remained procured on an annual basis until 2018. As has been elaborated in the special topic of this chapter, the costs for procuring reserves in 2018 nearly doubled, mainly caused by a tripling of the cost of contracting mFRR reserves.

[27] Dutch version: https://www.creg.be/nl/publicaties/beslissing-b1631
French version: https://www.creg.be/fr/publications/decision-b1631

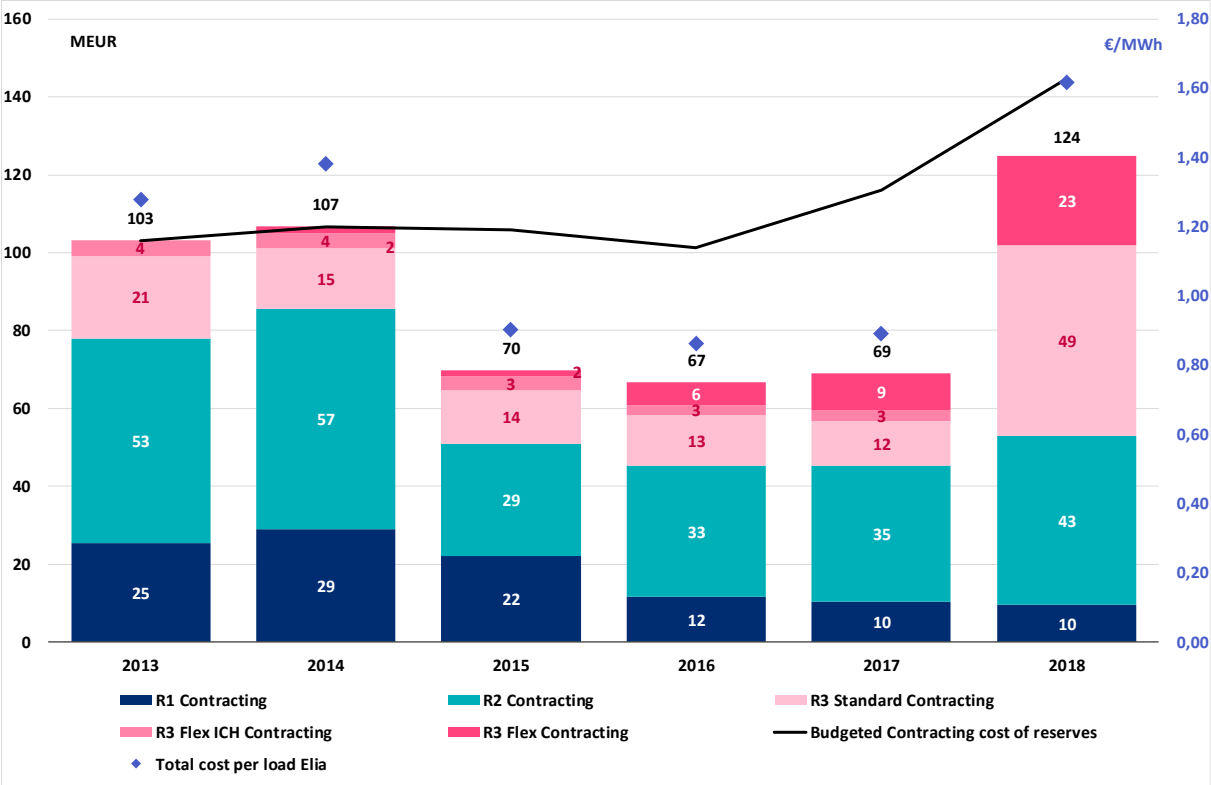


Figure 68 – Cost of contracting reserves, per year of contracting, per type of reserve. The reddish bars together form the reservation cost for tertiary reserves (mFRR). The black number presents the total cost for contracting reserves while the black line represents the budgeted cost. The purple diamonds indicate the cost of contracting reserves per unit of MW offtake in the Elia LFC Area.
Source: CREG based on data provided by Elia

103. The reservation of black-start ancillary services has increased in cost in recent years, from 6.25 MEUR in 2014 to 7.28 in 2017 (Table 32). In 2018 the cost for the reservation of black-start ancillary services remained stable. The cost for contracting ancillary services for the provision of reactive power continued its significant reduction from 0,50 MEUR in 2018. The costs of contracting reserves during 2015 to 2017 were far below the budgeted costs, as well as in 2018.

104. The reservation costs of power reserves are shared equally by consumers and producers, including the reservation cost for the black start service. The cost for contracting reactive power reserve is fully covered by consumers. Dividing the respective costs with the amount generated to and taken off the Elia grid gives the actual cost for individual producers and consumers in EUR/MWh. The cost for producers in €/MWh more than doubled with respect to 2017; the cost for consumers in €/MWh increased with 70%.

105. The actual cost differs compared with the necessary tariff as estimated by Elia for the tariff period 2016-2019[28]. Any deviation will be recovered (or added if the tariff was underestimated) during the next tariff period.

[28] http://www.creg.be/sites/default/files/assets/Tarifs/Elia/171222_ELIA_Tarifs2016_2019_NL.pdf

	2013	2014	2015	2016	2017	2018
Total Contracting Cost of reserves	103.090.000	106.730.000	69.775.880	66.700.340	69.097.580	123.985.895
Total Black-start Costs	6.200.000	6.246.000	6.262.000	7.191.900	7.273.929	7.278.866
Total Reactive Power Contracting	7.391.000	8.380.000	7.046.000	634.535	500.527	233.064
Budgeted Contracting cost of reserves	103.199.000	106.671.000	105.918.600	101.366.454	101.702.565	114.576.398
FCR	25.118.000	27.028.000	32.718.600	27.598.871	30.158.046	30.042.891
aFRR	52.560.000	53.611.000	55.188.000	52.929.342	50.828.168	56.551.323
mFRR	25.521.000	26.032.000	18.012.000	20.838.240	20.716.351	27.982.184
Budgeted Reactive Power Contracting			8.320.000	3.000.000	3.055.000	3.112.000
Covered by producers [€]	54.645.000	56.488.000	38.018.940	36.946.120	38.185.754	65.632.380
Covered by consumers [€]	62.036.000	64.868.000	45.064.940	37.580.655	38.686.281	65.865.444
Cost for producers [€/MWh]	0,75	0,92	0,66	0,52	0,53	1,11
Cost for producers [€/MWh]	0,77	0,84	0,58	0,49	0,50	0,86

Table 32 – Reservation costs for contracting ancillary services, per year, per ancillary service. Reactive power is excluded when calculating the cost for consumers in EUR/MWh.
Source: CREG based on data provided by Elia

5.3.2. Activated reserves

The payment of imbalance prices and imbalance tariffs follows Table 33, pursuant to article 55 of the EBGL.

	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

Table 33 – Flow of payments of imbalance prices, depending on the sign of the imbalance price (columns) and the imbalance in the perimeter of the BRP (rows).
Source: EBGL

106. From 2012, a single marginal pricing method is applied. Under this scheme, BRPs are incentivised to compensate for any system imbalance as they receive a remuneration from the TSO for doing so. BRPs aggravating the system imbalance must pay an equal price to the TSO and hence face a cost for the aggravation. In a well-functioning market, the BRPs aggravating the system imbalance will always pay an opportunity cost compared with the situation if they were balanced, as the imbalance price to be paid to the TSO will always be higher than the day-ahead price, which serves as a reference price. Similarly, BRPs helping the system imbalance receive an opportunity profit.

107. Additional incentivising components are added to the imbalance price to ensure that the imbalance tariff is sufficient to trigger a reaction from BRPs to system imbalances. This additional component does not penalize BRPs[29] helping the system while those aggravating the system imbalance are still penalized[30]. The marginal pricing method initiated a gradual decline in imbalance prices and provided convergence between the day-ahead reference price and the imbalance prices. The negative imbalance price is slightly lower than the day-ahead price, possibly indicating that positive system

[29] Penalization is done by adding a parameter β to the marginal price of the last activated resource to compensate for the system imbalance. The parameter's goal is to create a positive (negative) imbalance tariff that is lower (higher) than the marginal price of the last activated upward (downward) regulation resource. It discourages BRPs to help compensate for the system imbalance.

[30] Penalization is done by adding a parameter α to the marginal price of the last activated resource to compensate for the system imbalance. The parameter's goal is to create a positive (negative) imbalance tariff that is lower (higher) than the marginal price of the last activated downward (upward) regulation resource. It discourages BRPs to be imbalanced if they aggravate the system imbalance.

imbalances over 140 MW occur or that BRPs do not solve all portfolio imbalances on the day-ahead market.

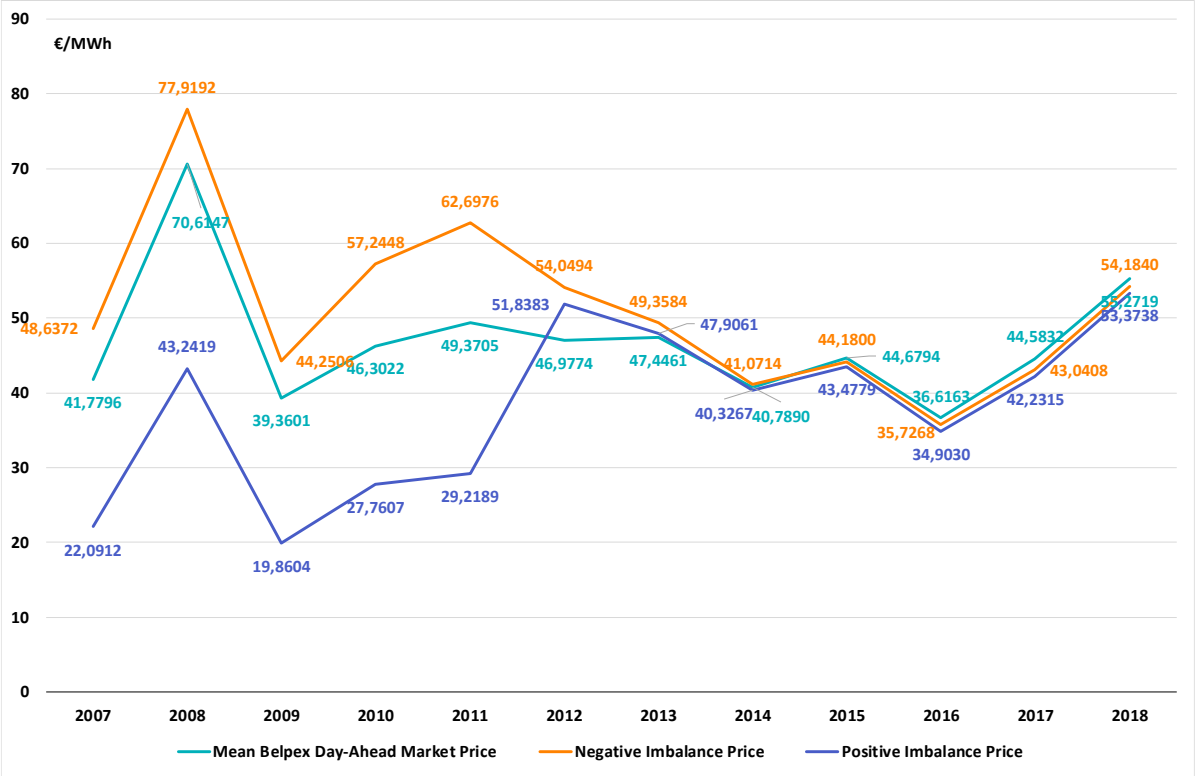


Figure 69 – Yearly averaged positive and negative imbalance tariffs. The yearly averaged day-ahead price serves as reference.
Source: CREG based on data provided by Elia

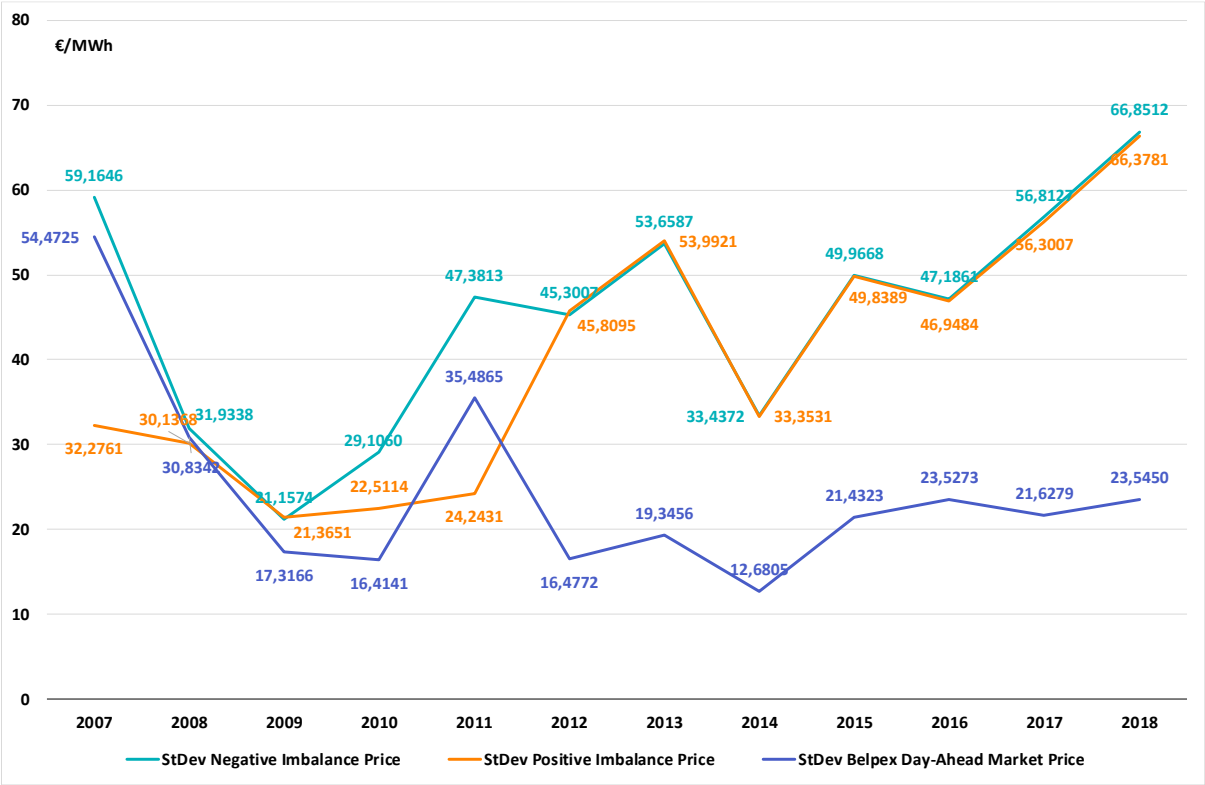


Figure 70 – Standard deviation of the positive and negative imbalance tariff
Source: CREG based on data provided by Elia

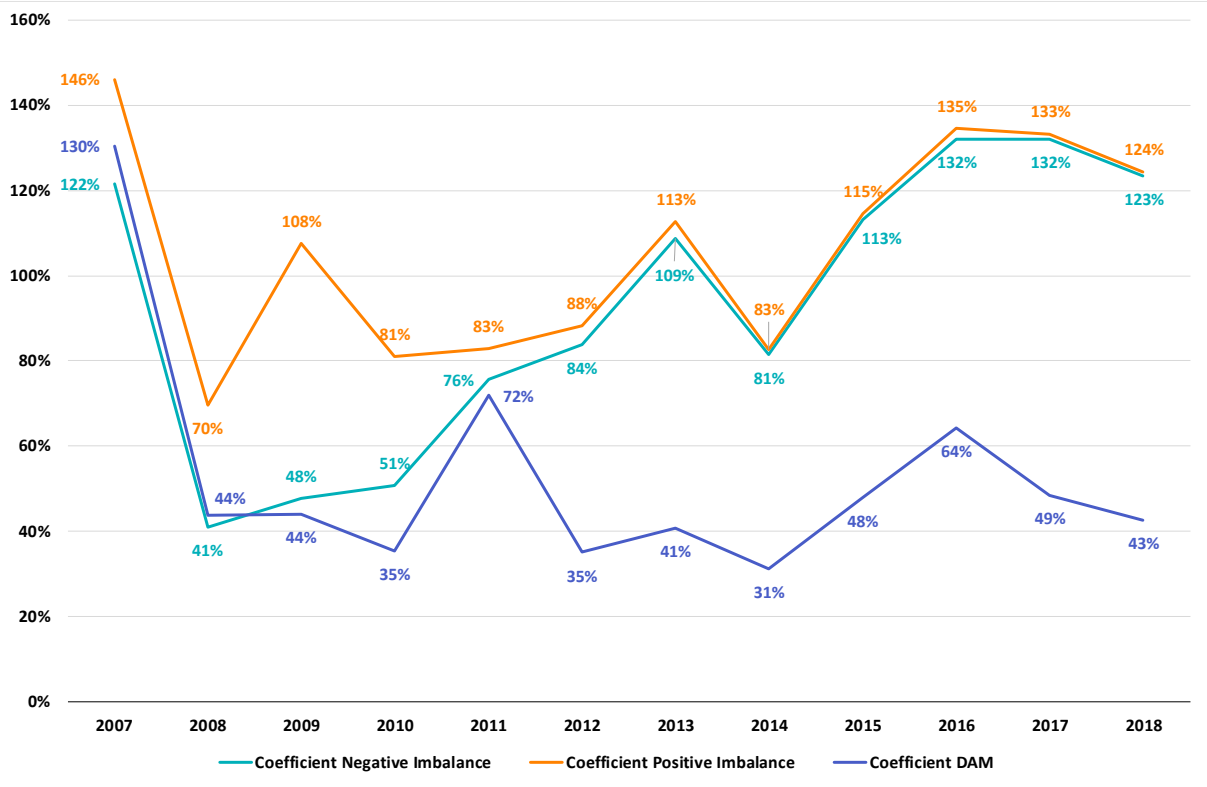


Figure 71 – Coefficient of variation of balancing tariffs and the day-ahead market price
Source: CREG based on data provided by Elia

108. The yearly standard deviation of positive and negative imbalance tariffs increased by €10.0/MWh in 2018 compared to 2017, while that of the day-ahead market price increased only slightly back to the level in 2016. The standard deviations of the positive and negative imbalance tariff are closely coupled.

109. The annual coefficient of variation[31] of the balancing tariffs declined in 2018 compared to 2017 and 2016, indicating that the relative risk has decreased. The coefficient on the day-ahead market has decreased as well. The yearly volatility of imbalance prices is however 3 times larger than those of day-ahead prices.

110. The activated energy, including imbalance netting (IGCC), remained stable in 2018 in comparison with 2017. Non-contracted mFRR, IGCC, and aFRR cover 98,4% of all balancing needs.

111. Imbalance netting and secondary control (R2/aFRR) are closely linked in nature. As it is calculated before activating aFRR, IGCC avoids aFRR activations and frees aFRR capacity for additional activations. As such, IGCC and aFRR can be considered as very similar in nature, even if IGCC is not a true activation, but through imbalance netting, a way to avoid physical activations. Both complement each other and their sum is relevant to show the increasing importance of automatic control of imbalances compensation.

[31] The coefficient of variation equals the standard deviation divided by the average. It is a scaled, relative value of volatility.

Figure 72 – Balancing energy activated by product type
Source: CREG based on data provided by Elia

6. SECURITY OF SUPPLY

6.1.1. Introduction

112. The CREG believes it is important to evaluate how close or far Belgium was from an adequacy problem. Did we just miss an involuntary load shedding by a hair, or was there still sufficient capacity for Belgium?

113. In May 2019, the CREG published its study on winter 2018-2019, which was impacted by a the unavailability of several nuclear power plants. In this study, the CREG developed an indicator to measure ex-post how much capacity was still available before involuntary load shedding would have to take place to avoid a black-out.

114. In this chapter, the part on the SoS-indicator from the study on the winter 2018-2019 will be re-incorporated into this monitoring report. In the following years, this indicator will be calculated and published in the yearly monitoring report.

115. For this, we will evaluate every day that saw, at least during one hour, a day ahead price equal to or higher than 300 €/MWh on the power exchange.

116. There were 6 such days in 2018: 24 September, 5 November, 20 November, 21 November, 22 November and 26 November. These days will be analyzed below.

117. In the analysis, the additional available capacity will be calculated before Belgium would have to envisage involuntary curtailment for the next day, because all demand could not have been met, even though market parties are willing to pay the highest price possible (i.e. 3.000 €/MWh).

118. To be able to calculate the additional capacity that would have been available if prices had gone to 3.000 €/MWh, four types of capacities are evaluated:

- 'Additional explicitly available domestic capacity': this is the additional capacity offered on the Belgian power exchange by Belgian market players. This can be calculated for each hour of the day, based on the aggregated supply and demand curves on the day-ahead power exchange.
- 'Additional explicitly available import': this is the additional capacity offered on the Belgian power exchange by foreign market players. This can be calculated for each hour of the day, as the difference of the actual import/export position and the maximal Belgian import capacity (with an additional check whether the resources are available on the foreign power exchanges).
- 'Additional implicitly available domestic capacity': this is an estimation by the CREG of the additional capacity not offered on the Belgian power exchange. This estimation is based on the data the CREG received from certain market players and consists mostly of the special measures that were taken by market parties to address the sudden adequacy crisis due to the unexpected nuclear unavailability.
- 'Available balancing reserve (R23)': the available balancing reserves for balancing the system. According to European legislation, these reserves need to be exhausted before involuntary load shedding[32]. The volume of these reserves are proposed by Elia and approved by the CREG. In 2018, these reserves had to be 139 MW on R2 (aFRR) and 830 MW on R3 (mFRR), totaling 969 MW.

[32] See article 21 of the network code on 'Emergency & Restoration': https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32017R2196&from=EN#d1e1893-54-1

119. In the next section, the total additional capacity will be calculated for each of the six days with a day-ahead price at or above 300 €/MWh for at least one hour. This capacity indicates how far Belgium was from involuntary load shedding.

120. As regards adequacy, the CREG focuses on the day-ahead time frame. It is also in day-ahead (and intraday) that a TSO should make an adequacy assessment[33]. The day-ahead is also the most liquid market and through the 'adequacy patch' the import capacity is prioritized for countries (price zones) who risk having insufficient capacity (and are therefore willing to pay the highest price possible).

121. However, the balancing reserves cannot be offered in the day-ahead timeframe, because these reserves need to be kept out of the day-ahead market and so these volumes have no impact on the day-ahead price formation. Hence, if the price on the day ahead market reaches the price cap and the adequacy patch is activated (increasing the import), the balancing capacity is still available as an extra buffer in real time if there is a problem with adequacy. This extra buffer should be taken into account in assessing how far Belgium was from involuntary load shedding.

6.1.2. Special days

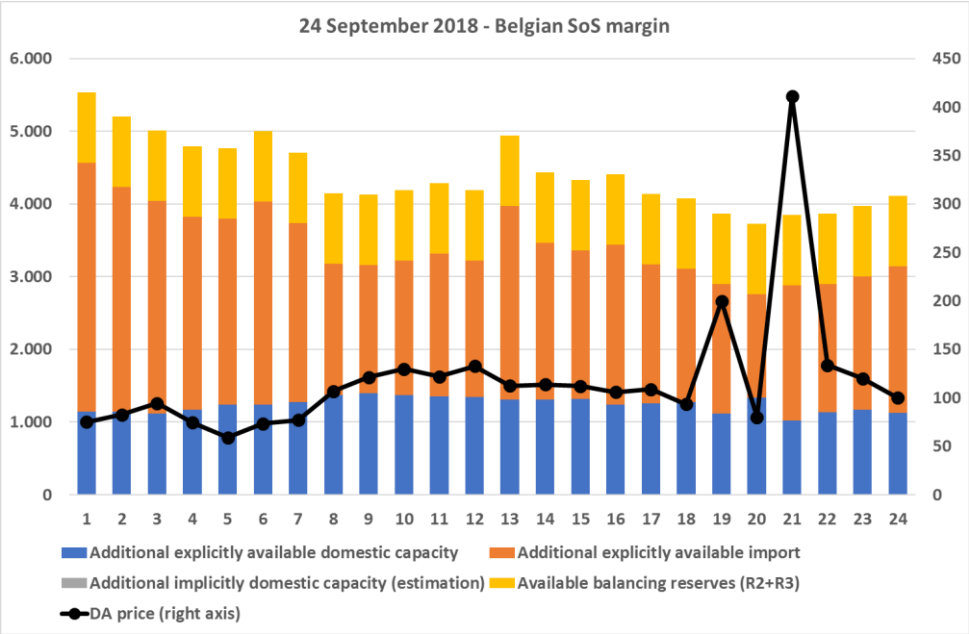
6.1.2.1. *24 September 2018*

122. On 24 September 2018, a day-ahead price of 411 €/MWh was reached for hour 21. The figure below shows for this day the available capacity there was still left in day-ahead before consumers would have to be curtailed.

123. Figure 45 shows that Belgium had still at least 3.700 MW of available capacity, of which at least 2,700 MW was explicitly available on the day-ahead power exchange. This means Belgium was still far from having a problem with security of supply. Note that for this day the estimation of implicitly available capacity that consists mostly of the special measures is estimated at zero, since by the end of September these measures were not yet taken.

[33] See article 107 of the Guideline on 'System Operation': https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32017R1485&from=EN

Figure 73 : Security of supply margin on 24 September 2018

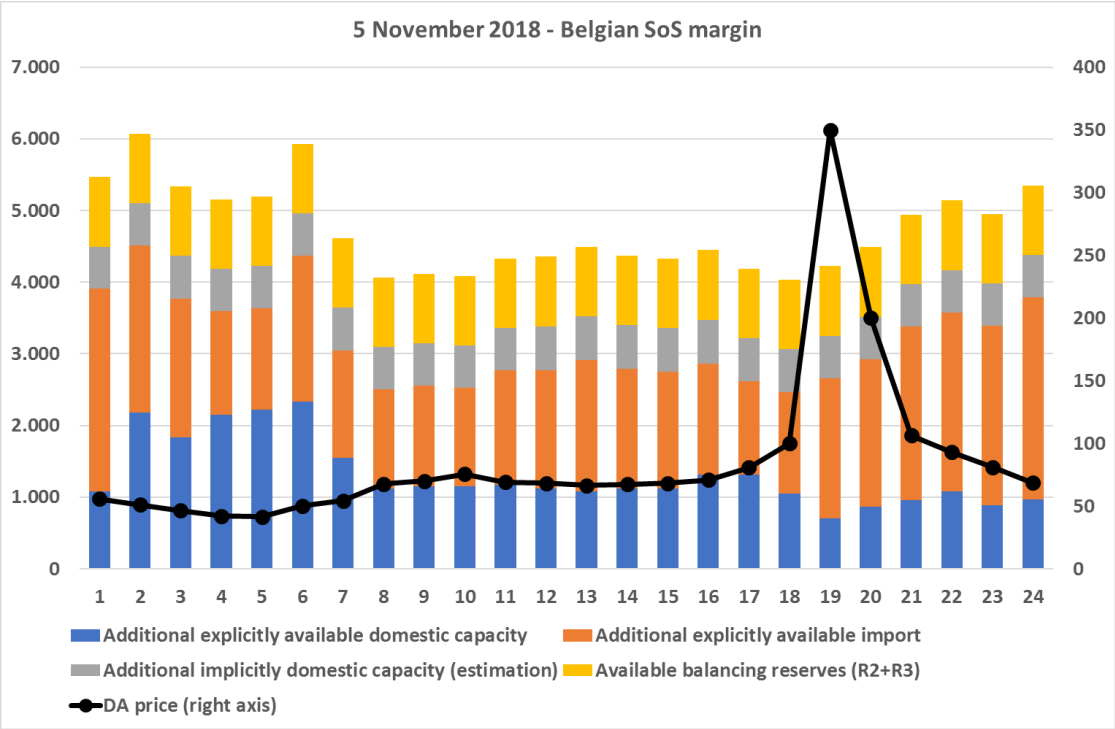


6.1.2.2. *5 November 2018*

124. On 5 November 2018, a day-ahead price of 350 €/MWh was reached for hour 19. The figure below shows for this day the available capacity there was still left in day-ahead before consumers would have to be curtailed.

125. Figure 46 shows that Belgium had still at least 4,000 MW of available capacity, of which at least 2,500 MW was explicitly available on the day ahead power exchange. This means Belgium was still far from having a problem with security of supply.

Figure 74: Security of supply margin on 5 November 2018

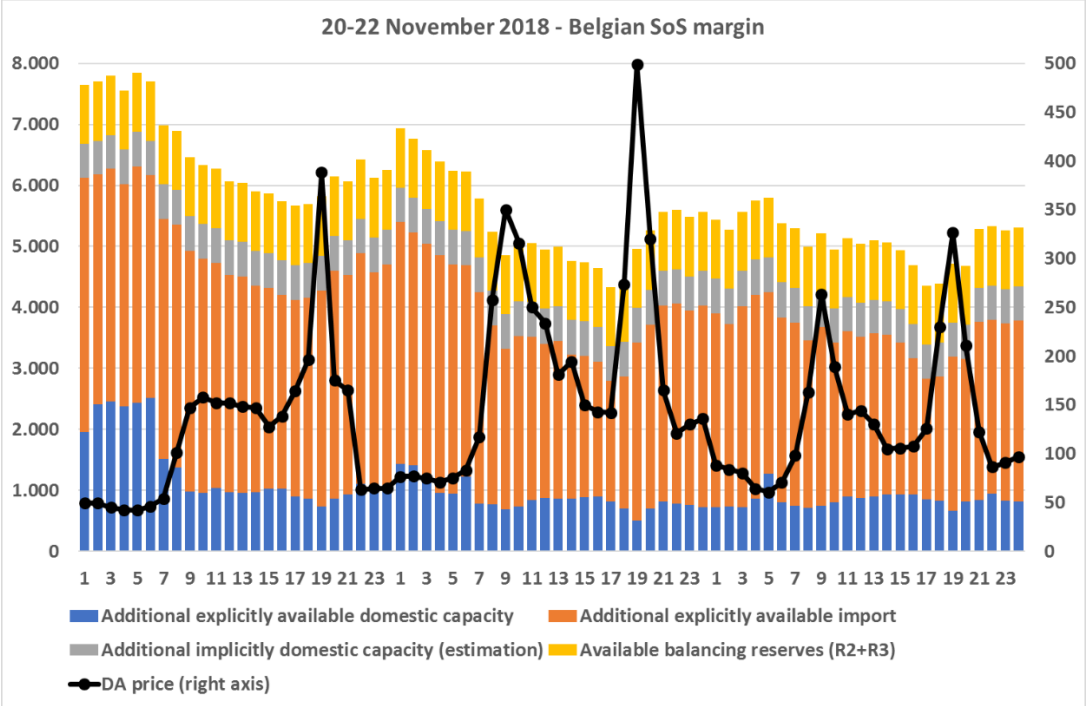


6.1.2.3. *20-22 November 2018*

126. On 20 to 22 November 2018, several day-ahead prices were above 300 €/MWh, with a maximum day-ahead price of 499 €/MWh reached on 21 November for hour 19. The figure below shows for this day the available capacity there was still left in day-ahead before consumers would have to be curtailed.

127. Figure 47 shows that Belgium had still at least 4,300 MW of available capacity, of which at least 2,700 MW was explicitly available on the day ahead power exchange. This means Belgium was still far from having a problem with security of supply.

Figure 75 : Security of supply margin on 20-22 November 2018

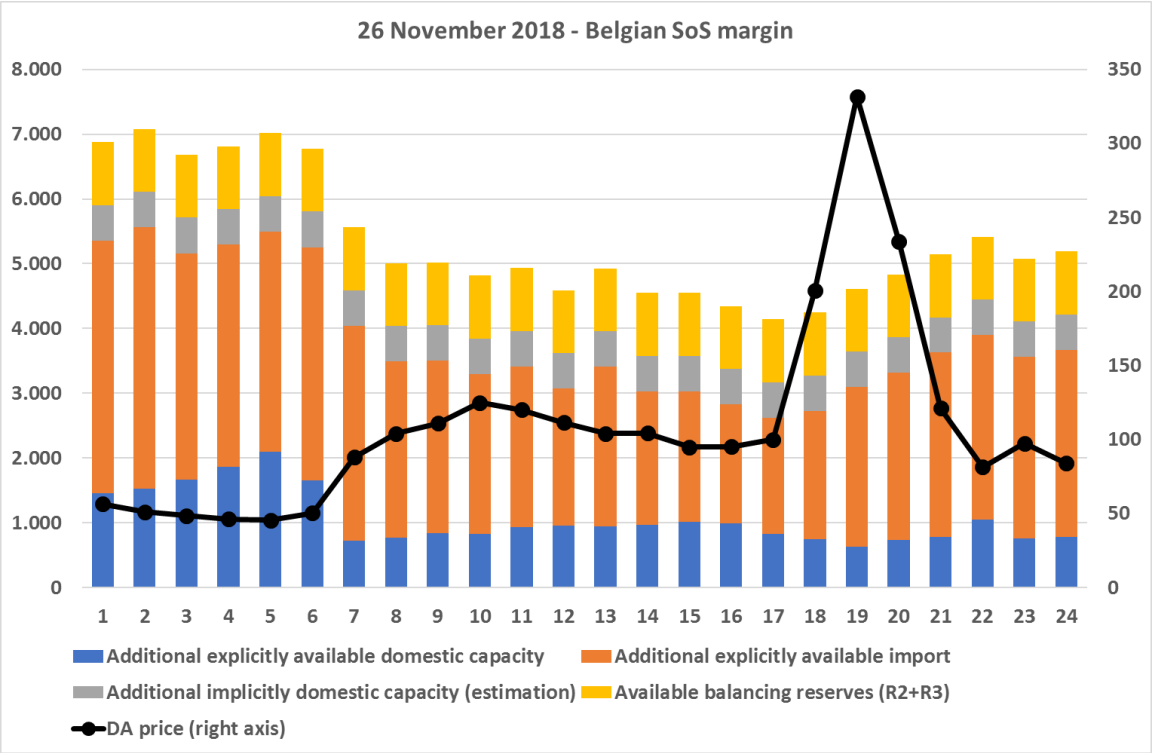


6.1.2.4. *26 November 2018*

128. On 5 November 2018, a day-ahead price of 331 €/MWh was reached for hour 19. The figure below shows for this day the available capacity there was still left in day-ahead before consumers would have to be curtailed.

129. Figure 48 shows that Belgium had still at least 4,100 MW of available capacity, of which at least 2,600 MW was explicitly available on the day-ahead power exchange. This means Belgium was still far from having a problem with security of supply.

Figure 76 : Security of supply margin on 26 November 2018



6.1.3. Conclusion

130. In 2018, there were 6 days with day ahead prices above 300 €/MWh, indicating a certain scarcity of capacity. All these days occurred at the end of 2018, when nuclear availability was historically low. However, from a detailed analysis of these days, it is clear that for all of them, there was more than sufficient capacity left to address an additional adversity, like losing another production unit or having a severe cold spell, without running the risk of involuntary load shedding. The minimum available capacity in the system is conservatively estimated as at least 3,700 MW, of which 2,500 MW of capacity was explicitly available on the day-ahead power exchange (most of it coming from imports). It is clear that there was still a large capacity margin, even though Belgium faced the lowest nuclear availability for more than 20 years.

131. Even this high volume is probably an underestimate of the adequacy margin, since the CREG only analyzed part of the market regarding the special measures that were taken to address the unexpected adequacy crisis. There could have been even more flexibility that was already implicitly available in the market. For example, more and more supply contracts are so-called pass-through contracts. With these contracts, the imbalance tariffs are “passed through” to consumers, incentivizing them to lower consumption when imbalance tariffs are high. The total market of these contracts easily surpasses 500 MW. This flexibility is not taken into account because the CREG has no information on whether these contracts are already counted for, thus avoiding the risk of double counting.

7. CONCLUSIONS

132. The Elia grid load in 2018 decreased slightly to 76.7 TWh compared to the previous years and is at its lowest level for the period under review starting in 2007. The maximum Elia grid load, at 12,750 MW, is also at its lowest level for this period.

133. The maximum Elia grid load in 2018 was 12,440 MW, significantly lower than all the previous years, confirming the downward trend of the Elia grid peak load.

134. Following years of stagnation, there was an increase of 20% in solar electricity generation. In 2018, solar panels produced 3.6 TWh, up from 2.9 TWh in 2017. There seems to be no significant impact of this increase of solar generation on the variability of the Elia grid load.

135. The total installed generation capacity increased from 14.1 GW to 15.4 GW in 2018, mainly due to an increase in installed offshore wind capacity and due to the market reaction after the announced unavailability of nuclear plants. In 2018, national generation decreased by almost 20% compared to 2017. In a special topic, the correlation between the age of a CCGT and nuclear units and their planned unavailability and forced outage rate were analysed. On average, an increased unavailability can be observed for older units. The analysis shows that this unavailability is mainly caused by an increase of planned unavailability for the older assets while the forced outage rate seems to be much less affected by the age of the units.

136. The evolution of the profitability of CCGT plants in Belgium was analysed in a special topic. The main conclusion of the topic is that the outlook of the profitability of an average CCGT plant in Belgium has recently improved. Since 2014, selling energy for delivery the next year has become increasingly profitable as both the frequency and absolute value of the average positive CSS has increased. The same conclusion, albeit a preliminary one, holds for sales for delivery the year after next year. The increase in profitability is primarily caused by European market evolutions given that for the next 2 years, the Belgian electricity mix and market forces still ensure that CCGT plants operate under mid- or peak-load conditions. The profitability based on baseload wholesale electricity products therefore enables CCGT plant operators to pursue multiple strategies to valorise their plants.

137. Average yearly day-ahead prices increased in each country in Central-West Europe (CWE) in 2018 compared to 2017. The increase is the result of structurally higher day-ahead prices and increases in prices during the last quarter of 2018. Prices never exceeded €500/MWh. The increase in day-ahead prices rippled through to forward markets in the CWE region, illustrating that scarcity prices in an energy-only market can provide the necessary longer term price signals, for example for the continued operation of existing peak power plants. Additionally, the electricity volume traded on the Belgian intraday market increased, surpassing 2 TWh. Primarily originating from cross-border trade, this indicates an increasing need for providing flexibility close to real-time, which provides opportunities for flexible generation units or demand facilities. [Next chapters]

138. Since 2013, following the introduction of a single price mechanism, the average imbalance tariff (the “real-time electricity price”), is very close to the average day-ahead price. This was also the case in 2018. As such, the average day ahead price serves as an unbiased predictor of the average real-time price. Significant hourly differences exist however, providing opportunities for small, flexible generation units or demand facilities. In 2018, 144 MW of aFRR and 780 MW of mFRR were contracted. Even though these volumes are similar to those contracted in 2017, the cost to cover the system risk doubled, mainly driven by increases in opportunity costs. The use of reserves for balancing the Elia grid was 690 GWh (down and up regulation combined), an increase with respect to the use of reserves in 2017, indicating that BRPs were less successful in maintaining their portfolios balanced on aggregate. Activation of 401 GWh of reserves was avoided with IGCC, a mechanism through which the imbalance of one country can be netted with other countries participating in the mechanism. Consequently, the

IGCC mechanism highlights, also for balancing and reserves, the importance for Belgium in cooperating at the European level in the interest of Belgian consumers. Lastly, 502 GWh of aFRR were activated (up and down) as well as 188 GWh of mFRR (up, down, contracted and non-contracted). Since 2013, following the introduction of a single price mechanism, the average imbalance tariff (the "real-time electricity price"), is very close to the average day-ahead price. This was also the case in 2018. As such, the average day ahead price serves as an unbiased predictor of the average real-time price. Significant hourly differences exist however, providing opportunities for small, flexible generation units or demand facilities. In 2018, 144 MW of aFRR and 780 MW of mFRR were contracted. Even though these volumes were similar to those contracted in 2017, the cost to cover the system risk doubled, mainly driven by increases in opportunity costs. The use of reserves for balancing the Elia grid was 690 GWh (down and up regulation combined), an increase with respect to the use of reserves in 2017, indicating that BRPs were less successful in maintaining their portfolios balanced on aggregate. Activation of 401 GWh of reserves was avoided with IGCC, a mechanism through which the imbalance of one country can be netted with other countries participating in the mechanism. Consequently, the IGCC mechanism highlights the importance for Belgium in cooperating at the European level in the interest of Belgian consumers, also for balancing and reserves. Lastly, 502 GWh of aFRR were activated (up and down) as well as 188 GWh of mFRR (up, down, contracted and non-contracted).

139. In 2018, there were 6 days with day-ahead prices above 300 €/MWh, indicating a certain scarcity of capacity. All these days occurred at the end of 2018, when nuclear availability was historically low. However, from a detailed analysis of these days, it is clear that for all these days there was more than sufficient capacity left to address additional adversity, like losing another production unit or having a severe cold spell, without running the risk of involuntary load shedding. The minimal available capacity in the system is conservatively estimated as at least 3,700 MW, of which 2,500 MW of capacity was explicitly available on the day ahead power exchange (most of it coming from imports). It is clear that there was still a large capacity margin, even though Belgium faced the lowest nuclear availability for more than 20 years.

For the Commission of Electricity and Gas Regulation:

Andreas TIREZ
Director

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Acting president of the Board of Directors

8. ANNEXES

8.1. GLOSSARY

3rd energy package : this title groups together

- two directives pertaining to gas and electricity markets ;
- two regulations concerning the access conditions to natural gas networks, and the access conditions to networks for cross-border electricity exchanges;
- the regulation establishing ACER.

CIM : Continuous Intra-day Market Segment, a market segment where instruments are traded by the continuous matching of purchase orders and delivery orders, without an opening auction, and for which the nomination of contracts concluded by Belgian market participants is carried out in accordance with the rules of Intra-day Internal Energy Transfer, in the ARP Contract.

Consumed capacity, at a given access point and in one quarter of an hour, is equal to the difference, to the extent that it is positive, between the capacity consumed by the loads connected to this access point, and the capacity injected by the local generation associated with this access point. If this difference is negative, the consumed capacity is zero (source: Elia).

Consumed energy, at one access point and for a given period, is equal to the total consumed capacity at this access point over the period of time considered (source: Elia).
E.g. : the consumed energy for a given load amounts to 100 MW for a quarter of an hour, to which a local generation is linked, injecting 40 MW during the same quarter of an hour, is equal to: 15 MWh = max (0, 100 MW – 40 MW) * 15 minutes.

DAM : Day-Ahead Market Segment', a market segment where instruments for which the delivery period relates to a precise hour of the day in accordance with the Exchange Day, are traded via auction following an order accumulation phase, and for which the nomination of the contracts concluded by Belgian market participants is carried out in accordance with the rules of Day-Ahead Internal Energy Transfer, in the ARP Contract.

Elia control area is the electric area for which Elia must maintain overall equilibrium between the supply and demand of electricity Elia has various means at its disposal to achieve this, including the secondary and tertiary reserves, as well as reserve agreements concluded with neighbouring system operators. The Elia control area covers Belgium and part of the Grand Duchy of Luxembourg (Sotel network).

The **Elia-grid load** is a calculation based on injections of electrical energy into the Elia grid. It incorporates the measured net generation of the (local) power stations that inject power into the grid at a voltage of at least 30 kV and the balance of imports and exports. Generation facilities that are connected at a voltage of less than 30 kV in the distribution networks are only included if a net injection into the Elia grid is being measured. The energy needed to pump water into the storage tanks of the pump-storage power stations connected to the Elia grid is deducted from the total. Decentralised generation that injects power at a voltage less than 30 kV into the distribution networks is not entirely included in the Elia-grid load. The significance of this last segment has steadily increased during the last years. Therefore Elia decided to complete its publication with a forecast of the total Belgian electrical load. The Elia-grid comprises networks of at least 30 kV in Belgium plus the Sotel/Twinerg grid in the south of Luxembourg. The **total load** incorporates all electrical loads on the Elia grid and in underlying distribution networks (and also includes electrical losses). It is estimated based on a combination of measurements and upscaled values of injections of power plants, including generation in the distribution networks, to which imports are added. Subsequently, exports and power used for energy storage are deducted, leading to an estimation of the actual total load in the Elia-grid and all underlying networks. (source: Elia).

Energy consumption at a given point of access is the energy consumed by the loads connected at this point of access (source: Elia). **Market coupling by prices**. In a system of coupling by price, each market participating in market coupling provides different data to a coordinated calculation system: the transmission capacity available at each border for each direction and for each period; the supply and demand curves for each period; the multi-hour orders "in blocks" submitted by the market participants. Based on this information, the exchanges determine the price and net position for each period, using a calculating algorithm, for each market participating in the market coupling. Since the introduction of market coupling by price, the prices between markets only vary if there is not enough available interconnection capacity between two markets. If there is a constraint at a given border, this means that the transmission capacity at the border is saturated, which results in congestion rent.

ENTSO-E, the *European Network of Transmission System Operators*, which represents 42 GRTs in 35 countries.

EPEX SPOT is an exchange which manages spot markets for electricity in France, Germany, Austria and Switzerland.

Equivalent temperature is obtained by adding 60% of the average temperature of Day X to 30% of the temperature of Day X-1, and by adding this result to 10% of the temperature of Day X-2 (source : http://www.aardgas.be/professioneel/over-aardgas/nieuws-en-publicaties/graaddagen).

The **Grid Control Cooperation** (hereinafter referred to as "**GCC**") is a collaboration between German GRTs. It aims to optimise the supply and activation of automatic secondary regulation. It is based on the observation that the regulation of different German control areas often act in opposite directions. It aims at balancing between these control areas the use of reserves acting in opposite directions, with the conditions that the resulting capacity flows do not hinder access to the network, and do not jeopardise the security of the network.

The GCC is made up of four modules:

- Module 1: reduction of the use of reserves in opposite directions;
- Module 2: reciprocal support in the event of a lack of secondary reserves;
- Module 3: technical coordination in the area of pre-qualification of a unit;
- Module 4: merit order lists for German control areas.

The decision was taken to leave open the possibility for other control areas to participate in module 1, which is known under the name of **IGCC**. Belgium started to participate in the IGCC in October 2012.

Heating value: there are two types, namely

- the Higher Heating Value (**HHV**) is the thermal energy released by the combustion of 1 kilogram of fuel. This energy includes sensible heat, but also latent heat from water evaporation, which is generally generated by combustion. This energy can be completely recovered if the water vapour released is condensed, in other words if all the evaporated water ultimately ends up in liquid form.
- the Lower Heating Value (**LHV**) is the thermal energy released by the combustion of 1 kilogram of fuel in the form of sensible heat, excluding energy from evaporation (latent heat) of the water present at the end of the reaction.

The difference between the two heating values is significant. The change of state (between vapour at 100°C and water at 100°C) absorbs or releases a significant amount of heat.
To increase the temperature of 1 litre of water by 1°C, 4.18 kJ is required. This is the specific heat value of water (4.18 kJ/kg/°C). Evaporation energy is the energy required to evaporate a substance at its evaporation temperature. The evaporation energy of water is approximately 540 calories per gram, or 2250 J/g (this energy depends on temperature and pressure). This means that to heat 1 litre of water from 0°C to 100°C (418 kJ), 5 times less energy is required compared to evaporating 1 litre of water at 100°C (2250 kJ).

IGCC "International Grid Control Cooperation".

Injected capacity, at a given access point and in one quarter of an hour, is equal to the difference, to the extent that it is positive, between the capacity injected by the associated generation at this access point, and the capacity consumed by the load(s) associated with this access point. If this difference is negative, the injected capacity is zero (source: Elia).

Injected energy, at one access point and for a given period, is equal to the total injected capacity at this access point over the period of time considered (source: Elia).
E.g. : the injected energy for a given load amounts to 40 MW for a quarter of an hour, to which a generation is linked, injecting 100 MW during the same quarter of an hour, is equal to: 15 MWh = max (0, 100 MW – 40 MW) * 15 minutes.

Instantaneous System Imbalance (SI) is calculated by taking the difference between the *Area Control Error* (ACE) and the Net Regulation Volume (NRV). The System Imbalance (SI) is obtained by neutralising the activated auxiliary services (NRV) – implemented by Elia to manage the equilibrium of the area – of the ACE.

Level of use of a generation unit is the energy actually generated, divided by the energy which the power station would have to generate as long as it generated at its maximum capacity every hour of the year.

Loop flows is the difference in the physical flows measured at the interconnections, and the expected flows based on total nominations for these interconnections.

Market coupling by volumes This coupling has been achieved between the CWE region (BE, DE, FR, NL, LU) and the Nordic region (NO, SE, DK, FI, ES). In this case, the available transmission capacities at each border for each direction and each period, as well as the net export curves of each country for each period, make it possible, using a calculation algorithm from the

company EMCC to define the flows on the interconnections between areas coupled by price. This information is then taken into account by the exchanges to calculate the prices in the different markets.

Market resilience indicates price sensitivity following an increase in supply or demand in the market.

Month-ahead is the Endex Power BE *Month* which represents the mathematical average expressed in €/MWh of the fixed reference prices at the "*end of day*" of the *month ahead* contracts (contracts for the physical supply of electricity on the Belgian high-voltage network for the month ahead), as published on the website http://www.iceendex.com/.

Net Regulation Volume (**NRV**) is calculated using the difference for each moment between the sum of the volumes of all upward regulations and the sum of the volumes of all downward regulations, including the exchanges via the International *Grid Control Cooperation* requested by Elia to maintain the balance of the control area. A positive value indicates a net upward regulation signal.

Nomination : a range of forecast data linked to an access point on the network. These data make it possible to define the characteristics of Day X and, in particular, the quantity of active capacity per quarter of an hour to be injected or consumed. These nominations are supplied by the ARP to Elia. Most nominations are shown as Day X-1 for the operation of the network on Day X. (source: Elia).

NORD POOL is an exchange which manages spot markets for electricity in the Nordics, the Baltics, Great-Britain and Germany.

Paradoxically rejected block orders (**PRB**) are non-convex offers which, based on the prices obtained from the market, should have been accepted but which were rejected anyway.

Quarter-ahead is the Endex Power BE Month which represents the mathematical average expressed in €/MWh of the fixed reference prices at the "end of day" of the quarter ahead contracts (contracts for the physical supply of electricity on the Belgian high-voltage network for the quarter ahead), as published on the website http://www.iceendex.com/**.**

Secondary reserve (R2) is a reserve which is activated automatically and continually, both upwards and downwards. It intervenes rapidly (from 30 seconds to 15 minutes) and remains active for the time required. This reserve regulates the current imbalances and is intended to continually re-establish the equilibrium within the control area of Elia, and to continually manage the frequency variations.

Spot Market : a completely electronic market for the anonymous trading of electricity blocks, organised and managed by a Nominated Electricity Market Operator (NEMO) in accordance with network codes and, for Belgium, also the Royal Decree. The Spot Market is made up of DAM and CIM market segments.

Spread: is the difference between the market price of electricity and its variable short-term cost, estimated on the basis of market prices for fuels, in other words an approximation of the very short-term gross margin;

- if CO_2 becomes an additional component of the variable cost, it is referred to as a clean spread;
- if the determination of the spread is calculated to generate with:
  - a coal-fired power station, it is referred to as a dark spread and,
  - a gas-fired power station, it is referred to as a spark spread.

Tertiary reserve (R3) is a capacity reserve which certain producers or industrial actors make available to Elia. It makes it possible to confront a significant or systemic imbalance in the control zone, offset significant frequency variations, and resolve significant congestion problems. This reserve is mobilised manually.

Use-It-Or-Sell-It (UIOSI) is the principle of transferring non-utilised capacity in the daily market**.**

Year-ahead is the Endex *Power BE Calendar* which represents the mathematical average expressed in €/MWh of the fixed reference prices at the "*end of day*" of the *calendar* contracts (contracts for the physical supply of electricity on the Belgian high-voltage network for the calendar year ahead), as published on the website http://www.iceendex.com/.

8.2. LIST OF ABBREVIATIONS

ACER	Agency for the Cooperation of Energy Regulators
AFCN	*Agence fédérale de Contrôle nucléaire* (Federal Agency for Nuclear Control)
ACER	Agency for the Cooperation of Energy Regulators, operational since 3 March, 2011
aFRR	Automatic Frequency Restoration Reserve
APX	Amsterdam Power Exchange
APX-ENDEX	currently the ICE - ENDEX Intercontinental Exchange
ARP	Access Responsible Party, which has concluded an ARP contract with the GRT Elia
AT	Austria
ATC	Available Transfer Capacity, a congestion management and capacity allocation method for cross-zonal exchange where cross-zonal transmission capacities are explicitly defined per border and per direction.
BE	Belgium
CACM	Capacity Allocation and Congestion Management
CASC	Capacity Allocating Service Company, namely an allocating platform for the auction of cross-border electricity transmission capacities for the CWE and CSE regions, the north of Switzerland and part of Scandinavia (jao.eu)
CCGT	Combined Cycle Gas Turbine
CCR	Capacity Calculation Region
CEE	Central East Europe, including Austria, Czech Republic, Slovakia, Hungary, Poland and Romania
CEER	Council of European Energy Regulators, created in 2000
CIM	Continuous Intra-day Market
CB	Critical Branch, network element either within or between bidding zones taken into account in the capacity calculation process, limiting the amount of power that can be exchanged
CBCO	Critical Branch Critical Outage, network element in the N-1 state either within or between bidding zones taken into account in the capacity calculation process, limiting the amount of power that can be exchanged
CO	Critical Outage, contingency taken into account in the capacity calculation process for compliance with the operational security limits.
CORE	The combination of Central West European (CWE) borders and Central East European (CEE) borders
CSE	Central South Europe region, including Germany, Austria, France, Greece, Italy and Slovenia
CSS	Clean Spark Spread
CWE	Central West Europe including Germany, Belgium, France, Luxembourg and the Netherlands, established on 9 November, 2010
D2CF	Two Day Ahead Congestion Forecast, TSOs' forecast of network loading in D-2 (best grid estimate in D-2)

DACF	Day Ahead Congestion Forecast, TSOs' forecast of network loading after day-ahead market coupling (best grid estimate in D-1)
DAM	Day-Ahead market
DE	Germany
DLR	Dynamic Line Rating, technology and methodology to integrate weather forecasts (temperature, wind…) in the assessment of a transmission line thermal limit as opposed to the use of static seasonal values.
EEX	European Energy Exchange
ENTSO	European Network of Transmission System Operators for Electricity (ENTSO-E) – and Gas (ENTSO-G)
ERGEG	European Regulators' Group for Electricity and Gas
EUPHEMIA	"Pan-European Hybrid Electricity market integration algorithm", selected for the PCR initiative
FAV	Flow Adjustment Variable, parameter in the Flow Based Market Coupling which can be introduced by a TSO to increase or decrease the RAM on a specific critical network element (see also: FBMC, RAM, CBCO).
FBI	Flow Based Intuitive, patch in the flow based market coupling which prevents imports from a higher price bidding zone (or export towards a lower price bidding zone).
FBMC	Flow Based Market Coupling, a congestion management and capacity allocation method for cross-zonal exchange where the market clearing point equals the set of net positions which maximizes the Social Welfare objective within the feasible domain defined by the network constraints (see: CBCOs).
FBP	Flow Based Plain, original result of the Flow Based Market Coupling without or prior to any patches
FCR	Frequency Containment Reserve
FR	France
Fref	Reference flows, physical flows observed in the D2CF basecase
$Fref_0$	Zero-balanced Reference flows, physical flows observed in the zero-balanced basecase, i.e. the case which starts from the D2CF base case and where all Net Positions are brought back to zero (no cross-zonal exchange).
Fref'	Zero-balanced Reference flows including the physical flows induced by long term nominations. These physical flows get priority access to the grid. They are taken into account in determining the capacity available for the market (see also: RAM, CBCO, FBMC).
FTR	Financial Transmission Right, type of long term transmission right entitling its holder to receive a financial remuneration based on the Day Ahead Market results between two Bidding Zones during a specified period of time in a specific direction (see also : PTR).
GME	Gestore Mercati Energetici, operator in the Spanish market for electricity and gas
GRT	*gestionnaire du réseau de transport* (Transmission System Operator : TSO)
GSK	Generation Shift Key, a method of translating a change of zonal net position into estimated specific injection increases or decreases in the common grid model.
HHI	Herfindahl-Hirschman Index: measure of the concentration of the market
ICH	interruptible customers
ID-bids	incremental/decremental bids

IRM	*Institut royal météorologique* (Royal Meteorological Institute)
IGCC	International Grid Control Cooperation for imbalance netting
ITVC	Interim Tight Volume Coupling
JAO	Joint Allocation Office
LU	Luxembourg
LTA	Long Term Allocation of transmission capacity
M€	million euros
MCR	Multi-Regional Coupling
mFRR	Manual Frequency Restoration Reserve
NEMO	Nominated Electricity Market Operator
NEP	Net (Exchange) Position, the netted sum of electricity exports and imports for each market time unit for a bidding zone
NL	Netherlands
NRV	Net Regulation Volume is calculated using the difference for each moment between the sum of the volumes of all upward regulations and the sum of the volumes of all downward regulations, including the exchanges via the International Grid Control Cooperation requested by Elia to maintain the balance of the control area. A positive value indicates a net upward regulation signal.
NTC	Net Transfer Capacity = TTC (Total Transfer Capacity) – TRM (Transmission Reliability Margin).
NWE	North West Europe**:** including Germany/Austria, the Benelux, Denmark, Estonia, Finland, France, Great Britain, Latvia, Lithuania, Norway, Poland and Sweden.
OMIE	OMI-Polo Español S.A. operator in the Spanish market for electricity and gas
OTC	Over-the-counter or off-exchange
OTE	Operator in the Czech market for electricity and gas
PCI (HHV)	Higher Heating Value (see also glossary)
PCR	Price Coupling of Regions, an initiative of 7 European exchanges to develop a single algorithm to calculate a single coupling price in Europe, and to improve the efficiency of allocations of cross-border interconnection capacities on a day-ahead basis.
PCS (LHV)	Lower Heating Value (see also glossary)
PLEF	The Pentalateral Energy Forum, framework for regional cooperation in Central Western Europe (BENELUX-DE-FR-AT-CH) towards improved electricity market integration and security of supply. The initiative aims to give political backing to a process of regional integration towards a European energy market. This cooperation is formalized trough the PLEF MOU signed in 2007.
PST	Phase-Shifting Transformer, a transformer for controlling the power flow through specific lines, without changing voltage level
PTDF (nodal)	Nodal Power Transfer Distribution Factor, (set of) parameter of a critical network element representing the physical flow induced by a change in nodal net position(s) – depends on grid topology.

PTDF (zonal)	Zonal Power Transfer Distribution Factor, (set of) parameters of a network element representing the physical flow induced by a change in zonal net position(s) – depends on grid topology and on GSK.
PTR	Physical Transmission Rights, type of long term transmission right entitling its holder to physically transfer a certain volume of electricity in a certain period of time between two Bidding Zones in a specific direction (see also : FTR)
PV	Photovoltaic panels
PWR	Pressurized Water Reactor
R1	Primary Reserve or Primary Control Power; name of FCR in the Electricity Balancing Guidelines
R2	Secondary Reserve or Secondary Control Power**;** called aFRR in the Electricity Balancing Guidelines
R3	Tertiary Reserve or Tertiary Control Power; called mFRR in the Electricity Balancing Guidelines
R3 DP	R3 on dynamic profiles (offtakes and decentralized generation)
R3 ICH	R3 on interruptible offtakes
RAM	Remaining Available Margin, capacity (in MW) of a Critical Branch Critical Outage (see: CBCO) which is given to the market
REMIT	Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency
RR	Replacement Reserve; not used by ELIA
SER - EnR	Sources of renewable energy
SWE	South West Europe
TGV	*Turbine Gaz-Vapeur* (Combined Cycle Gas Turbine)
TLC	Trilateral Market Coupling of the Belgian (Belpex), French (Powernext) and Dutch (APX) electricity markets, established on 21 November 2006 with the GRTs TenneT, Elia and RTE.
TSO	Transmission System Operator
TTC	Total Transfer Capacity
TRM	Transmission Reliability Margin
UIOSI	Use-It-Or-Sell-It
XBID	**Cross-border Intraday**

Units

EUR	euro
GW	gigawatt, equal to 1 billion watts
kV	kilovolt
MEUR	million euro
mHz	millihertz, unit of frequency
MW	megawatt, equal to 1 million watts
MWh	megawatt hour, equal to 3.6 billion megajoules
TW	terawatt, equal to one thousand billion watts
W	Watt, unit of measurement for capacity derived from the international system of units, which measures the rate of electric conversion

8.3. LIST OF FIGURES

8.4. LIST OF TABLES