Commissie voor de Regulering
van de Elektriciteit en het Gas

Study

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Study on the functioning and price evolution of the Belgian wholesale electricity market - Monitoring Report 2022

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

Non-confidential

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EXECUTIVE SUMMARY

English

The Belgian and European electricity markets have undergone a profound shock and remarkable evolutions in 2022. By many accounts, the observations in this annual monitoring report are far beyond their normal range. These observations show the response of all actors across the value chain of electricity, from producers, network operators, producers, consumers and traders, to the drastically changed circumstances in the electricity sector.

Belgium's total **consumption of electricity** reached 81,7 TWh in 2022. This represents a 3,2% decrease compared to 2021 (84,4 TWh). The consumption was only slightly higher than the exceptionally low 81,1 TWh in 2020, which resulted from the confinement measures and economic contraction in the context of the Covid-19 pandemic.

At the same time, the load from the transmission network amounted only to 64,0 TWh, a staggering 9,7% below the 70,9 TWh in 2021. The decline in grid load contrasts with the significant increase in unmetered, locally consumed electricity generation, for example through residential solar installations or distribution-connected wind generation.

The consumption of electricity remains highly dependent on meteorological conditions. In line with the observations of previous years, relatively low and high temperatures lead to an increase in the demand for electricity, mainly for heating and cooling purposes. This leads to a confirmation of the seasonal trend for electricity consumption in 2022: relatively low consumption levels in the summer against higher levels in the winter.

For the first time, this report attempts to distinguish consumption levels for large industrial consumers and small households separately. It is clear that different trends can be observed. For large industrial consumers, the demand for electricity increased significantly in the first half of 2022 compared to the previous years, but dropped to (much) lower levels in the second half, following the extremely high price peaks in the summer of last year. The monthly load from the distribution level is, with the exception of March and April, consistently below the same levels of the previous years – again due, in a large part, to the increase in unmetered, locally consumed electricity generation.

The availability of **electricity generation** units decreased in 2022, mostly resulting from a lower availability of nuclear and hydro units. The planned maintenances of Tihange 1 led to a decrease in the availability rate for nuclear reactors from 90% in 2021 to 76% in 2022.

The total generated electricity volumes decreased with 3,7 % year-on-year, from 93,4 TWh in 2021 to 89,9 TWh in 2022. The largest decrease by fuel type was observed for nuclear units (-6,2 TWh), while solar (+1,7 TWh), gas (+0,9 TWh) and wind (+0,1 TWh) increased their output.

The greenhouse gas emission intensity of electricity production in Belgium reached 165 gCO2-eq / kWh in 2022, showing a remarkable decrease of 39,2% since 2000. Given the volatility of the generation mix in Belgium, driven by the (un)availability of nuclear units, several short and small increases in GHG intensity of Belgian production have been observed, in 2015, 2018 and 2022.

Cross-border flows of electricity remained a crucial tool to balance supply and demand of electricity, and ensure that the dispatch of electricity production considers efficiently the price signal. At 19,2 TWh, the total exported volumes of electricity remained at a very high level in 2022, only slightly below the record high values observed in 2021 (20,0 TWh). This led to 2022 being the fourth consecutive year where Belgium was a net exporter of electricity, with a net export position of 6,3 TWh. Since early 2019, Belgium has had a structural positive net export balance, indicating that more electricity was exported than imported, explaining the positive difference between electricity generation and electricity consumption.

The prices observed on the **long-term futures markets** for delivery in Belgium have been consistently high with a few price peaks throughout 2022, after having started to rise from mid-2021 onwards. Prices for delivery in 2023 ("Cal-23") were consistently above 100 €/MWh throughout 2022, rising to almost 800 €/MWh for baseload contracts towards the end of August.

At the same time, prices for delivery in 2022 were significantly lower through the available futures contracts (for example one to three years ahead) than through the day-ahead market for the same delivery period – consumers or utilities that have hedged their position through year-ahead futures would have paid nearly 200 €/MWh less (with Y+3 contracts bought in 2018) than in the day-ahead market. Reported volumes through the futures exchanges show that the hedged volumes for delivery in 2022 have been much higher than the previous years – especially compared to 2020 and 2021.

The sales of interconnection capacity through long-term transmission rights, under the available product formats (physical or financial transmission rights) have generated high incomes for Elia. The prices for these transmission rights increased strongly, especially for export towards France and – during some months – to Great Britain. The prices paid during these auctions sometimes far exceeded the day-ahead market spreads between these zones, generating a net revenue for the transmission system operator. About three quarters of the allocated volumes during monthly and yearly auctions have been sold at prices exceeding the day-ahead spread for the corresponding delivery period, hence creating a net revenue for Elia.

A particular point of attention remains the sufficiency of the offered cross-zonal transmission capacities to cover the hedging needs of market participants: the requested volumes were, in 2022 just as in previous years, many times higher than the offered volumes. Depending on the price elasticity of the demand for transmission rights (not assessed in this report), increasing the capacities made available during long-term auctions would benefit both market participants (allowing better hedging) and Elia (generating higher revenues).

The electricity volumes bought and sold on **day-ahead markets** have continued their upwards trend over the last years, reaching 22,1 TWh or 27,0% of the total Belgian electricity consumption. The market shares of the two active NEMOs started to move in a more balanced direction than historically the case: 79,2% for EPEX SPOT versus 20,8% for Nord Pool.

The combination of the volumes bought and sold for both NEMOs in Belgium have translated into a net export position of, on average, +673 MWh/h throughout all hours of 2022. This is a remarkable increase compared to previous years, especially given the departure of the United Kingdom from the Internal Energy Market implies that the volumes exchanged over the Nemo Link interconnector are not included here, and accounted for separately.

The day-ahead prices in Belgium have increased far beyond their historical levels. The average price in 2022 (244,5 €/MWh) is more than twice the value in 2021 (104,1 €/MWh) and almost 6 times the historical average between 2015 and 2020 (42,1 €/MWh). Three distinct periods with short but extremely high price peaks have been observed throughout the year: in early March, end August and early to mid-December.

At the same time, price convergence has decreased, both on a global level as well as on an individual border-to-border level. This decrease went hand in hand with an increase in the observed price spreads between the coupled bidding zone. The occurrence of price divergence, caused by the inability of the transmission network to sufficiently accommodate the required exchanges to make prices converge, is particularly worrisome in the context of observed congestions and low margins for cross-zonal exchanges.

The successful introduction of the Core day-ahead flow-based market coupling project in June 2022 can be considered as one of the most important milestones in European market coupling of the past decade. Despite the operational success, some significant shortcomings can be observed in this report, particularly related to the structural application of allocation constraints and individual validation adjustments. These mechanisms impede the ability of the flow-based mechanism to deliver on its full potential: in particular the low margins available for cross-zonal exchanges still, after many years, continue to be a problem.

In the **intraday markets**, the exchanged volumes increased from 2,9 TWh in 2021 to 4,4 TWh in 2022. Despite the competition between power exchanges, the market shares are more distorted in favour of the incumbent than in the day-ahead markets (89,3 % for EPEX SPOT; 10,7% for Nord Pool).

The reference prices, calculated on the basis of the volumes exchanged through the continuous intraday market coupling mechanism XBID, have increased in a manner very similar to the day-ahead prices. Despite closely matching the price levels over longer periods, very short and large differences can be observed between both price indexes on an hourly level: before 2020 these differences rarely exceeded 20 €/MWh in either way.

The calculation of available cross-zonal capacity remains, as in the day-ahead timeframe, a particular point of attention for intraday exchanges. The increase in the number of hours where no capacity can be made available at all severely impacts the ability of market participants to balance their position in real-time, by preventing them to trade across borders. This is, in part, a coordination problem between the relevant TSOs: increase requests by one TSO are often not accepted by another, because of the latter's inability to accommodate the flows from these increased exchanges in the intraday timeframe.

SAMENVATTING

Nederlands

De elektriciteitsmarkten in België en Europa hebben in 2022 een diepgaande schok ondergaan, hetgeen een aantal opmerkelijke evoluties heeft blootgelegd. De observaties in dit rapport liggen, in vele opzichten, ver buiten hun normale bereik. Deze observaties weerspiegelen de acties van alle actoren doorheen de waardeketen van elektriciteit, van producenten, netbeheerders, producenten, consumenten en tussenpersonen, als antwoord op de drastisch gewijzigde omstandigheden in de elektriciteitssector.

Het totale elektriciteitsverbruik bedroeg 81,7 TWh in 2022 in België. Dit vertegenwoordigt een afname met 3,2% ten opzichte van 2021 (84,4 TWh). Deze consumptie was slechts licht hoger dan de uitzonderlijk lage 81,1 TWh in 2020, die het gevolg was van de lockdownmaatregelen en de economische terugval in de context van de Covid-19 pandemie.

Tegelijkertijd bedroeg de belasting van het transmissienetwerk slechts 64,0 TWh, een uiterst sterke daling met 9,7 % ten opzichte van de 70,9 TWh in 2021. De afname in de netbelasting contrasteert met de significante toename van de ongemeten, lokaal verbruikte elektriciteitsproductie, bijvoorbeeld door residentiële zonnepanelen of windproductie aangesloten op het distributienetwerk.

Het elektriciteitsverbruik blijft sterk gerelateerd aan de meteorologische omstandigheden. Net zoals voorgaande jaren leiden relatief lage en relatief hoge temperaturen tot een toename van de elektriciteitsvraag, voornamelijk voor verwarmings- en koelingsdoeleinden. Dit leidt tot een bevestiging van de seizoensgebonden tendens van de elektriciteitsconsumptie in 2022: relatief lage verbruiksniveaus in de zomer ten opzichte van relatief hoge niveaus in de winter.

Voor de eerste maal tracht dit rapport een onderscheid te maken tussen de verbruiksniveaus voor grote, industriële klanten en kleine huishoudens. Verschillende trends kunnen worden waargenomen. Voor grote industriële klanten steeg het verbruik in de eerste helft van 2022 sterk ten opzichte van de voorgaande jaren, gevolgd door een daling naar (veel) lagere niveaus in de tweede helft. Deze daling was mogelijk het gevolg van de extreme prijspieken in de zomer van het afgelopen jaar. De maandelijkse gemiddelde belasting van de distributienetten lagen, met uitzondering van de maanden maart en april, consistent lager dan de niveaus van de voorgaande jaren – opnieuw, grotendeels, als gevolg van de toename in de niet gemeten, lokaal geconsumeerde elektriciteitsproductie.

De beschikbaarheid van de eenheden voor elektriciteitsproductie nam af in 2022, voornamelijk als gevolg van de verminderde beschikbaarheid van nucleaire eenheden en waterkrachtcentrales. Het geplande onderhoud van Tihange 1 leidde tot een afname van de beschikbaarheidsgraad voor nucleaire eenheden van 90% in 2021 tot 76% in 2022.

Het totale volume aan geproduceerde elektriciteit nam met 3,7% af op jaarbasis, van 93,4 TWh in 2021 tot 89,9 TWh in 2022. De grootste afname, bekeken over alle brandstoftypes, wordt geobserveerd bij nucleaire eenheden (-6,2 TWh), terwijl zon (+1,7 TWh), gas (+0,9 TWh) en wind (+0,1 TWh) hun productie verhoogden.

De koolstofintensiteit van de elektriciteitsproductie in België bedroeg 165 gCO2-eq per kWh in 2022, hetgeen een opmerkelijke afname met 39,2% ten opzichte van 2000 vertegenwoordigt. Gezien de volatiliteit van de productiemix in België, onder invloed van de (on)beschikbaarheden van nucleaire eenheden, zijn verschillende korte en lichte toenames van de broeikasgasintensiteit van de Belgische productie waar te nemen, in 2015, 2018 en 2020.

De grensoverschrijdende elektriciteitsstromen blijven een cruciaal hulpmiddel om het aanbod aan en de vraag naar elektriciteit te verzekeren, en om te garanderen dat de dispatch van de elektriciteitsproductie op efficiënte wijze het prijssignaal volgt. De totale uitgevoerde volumes bleven, met 19,2 TWh, op een zeer hoog niveau en slechts licht onder de recordwaarde van 2021 (20,0 TWh). Dit leidde ertoe dat, in 2022, voor het vierde opeenvolgende jaar, België een netto uitvoerder van elektriciteit was. De netto-uitvoer bedroeg 6,3 TWh. België heeft, sinds 2019, een structureel overschot op de handelsbalans voor elektriciteitsuitvoer, hetgeen erop wijst dat meer elektriciteit wordt geëxporteerd dan geïmporteerd en een verklaring biedt voor het positieve verschil tussen de elektriciteitsproductie en -consumptie.

De prijzen die werden geobserveerd op de langetermijnmarkten voor levering in België bleven op een consequent hoog niveau, met een aantal prijspieken doorheen 2022. Deze stijging begon in het midden van 2021. De prijzen voor levering in 2023 ("Cal-23") waren consistent boven 100 €/MWh doorheen 2022, met een stijging tot bijna 800 €//MWh voor basislastcontracten naar het einde van augustus toe.

Tegelijkertijd waren de prijzen voor levering in 2022 significant lager voor de beschikbare termijncontracten (bijvoorbeeld één tot drie jaren op voorhand) dan via de day-aheadmarkt voor dezelfde leveringsperiodes – consumenten of bedrijven die hun posities op voorhand via jaarcontracten indekten, hebben tot bijna 200 €/MWh minder betaald (via Y+3 contracten afgesloten in 2018) dan via de day-aheadmarkt. De uitgewisselde volumes op de georganiseerde termijnmarkten tonen aan dat de ingedekte volumes voor levering in 2022 veel hoger lagen dan de voorgaande jaren – in het bijzonder in vergelijking met 2020 en 2021.

De verkoop van grensoverschrijdende capaciteit met langetermijncontracten via de beschikbare producten (fysieke of financiële transmissierechten) heeft hoge inkomsten gegenereerd voor Elia. De prijzen voor deze transmissierechten stegen sterk, in het bijzonder voor uitvoer naar Frankrijk en – gedurende een aantal maanden – naar Groot-Brittannië. De prijzen die tijdens deze veilingen werden betaald, overtroffen vaak sterk de prijsverschillen tussen de betrokken zones in de day-aheadmarkten, waardoor een netto inkomst voor de transmissiesysteembeheerders wordt gegenereerd. Ongeveer driekwart van de toegewezen volumes tijdens maand- en jaarveilingen werd verkocht aan prijzen die het day-ahead prijsverschil voor de overeenkomstige leveringsperiode overschreed, waardoor een netto-inkomst voor Elia werd gegenereerd.

De toereikendheid van de aangeboden grensoverschrijdende transmissiecapaciteit om aan de indekkingsnoden van marktdeelnemers te voldoen, blijft een bijzonder aandachtspunt: de door marktdeelnemers gevraagde volumes lagen, in 2022 maar ook in de voorgaande jaren, vele malen hoger dan de aangeboden volumes. Afhankelijk van de prijselasticiteit van de vraag naar transmissierechten (niet berekend in dit rapport), zou het verhogen van de beschikbare capaciteiten een positief effect kunnen hebben voor zowel marktdeelnemers (door toegenomen indekkingsmogelijkheden) als Elia (door het genereren van hogere inkomsten).

De volumes die werden gekocht en verkocht op de day-aheadmarkten bevestigden de stijgende trend van de afgelopen jaren en bereikten 22,1 TWh of 27,0% van het totale elektriciteitsverbruik in België. De marktaandelen van de twee in België actieve NEMOs evolueerden in een meer evenwichtige richting dan hetgeen historisch het geval was: 79,2% voor EPEX SPOT en 20,8% voor Nord Pool.

De day-aheadprijzen in België zijn ver boven hun historische niveaus uitgestegen. De gemiddelde prijs bedroeg, in 2022, met 244,5 €/MWh meer dan tweemaal de waarde van 2021 (104,1 €/MWh) en bijna zesmaal het historisch gemiddelde tussen 2015 en 2022 (42,1 €/MWh). Drie afzonderlijke periodes met korte maar extreem hoge prijspieken werden geobserveerd doorheen het jaar: begin maart, eind augustus en begin tot midden december.

Tegelijkertijd nam de prijsconvergentie af, zowel op globaal op individueel (grens per grens) niveau. Deze afname ging hand in hand met een toename van de geobserveerde prijsverschillen tussen de gekoppelde biedzones. Prijsdivergentie, veroorzaakt door de ontoereikendheid van transmissienetwerk om de voor prijsconvergentie noodzakelijk grensoverschrijdende uitwisselingen mogelijk te maken, is vooral zorgwekkend in de context van de geobserveerde congesties en de lage beschikbare transmissiecapaciteiten.

De succesvolle go-live van de stroomgebaseerde marktkoppeling in de Core regio in juni 2022 kan algemeen worden beschouwd als één van de belangrijkste mijlpalen in de Europese marktkoppeling van het afgelopen decennium. Ondanks het operationele succes worden een aantal belangrijke problemen geobserveerd in dit rapport, in het bijzonder gerelateerd aan het structureel toepassen van allocatiebeperkingen en individuele validatiewijzigingen. Deze mechanismen beperken de mogelijkheid van de stroomgebaseerde marktkoppeling om haar volledige potentieel te benutten: de lage marges voor zoneoverschrijdende uitwisselingen blijven, na vele jaren, een groot probleem.

In de **intradaymarkten** stegen de uitgewisselde volumes van 2,9 TWh in 2021 naar 4,4 TWh in 2022. Ondanks de competitie tussen de elektriciteitsbeurzen bleven de marktaandelen sterk in het voordeel van de historische beurs dan in de day-aheadmarkten (89,3% voor EPEX SPOT; 10,7% voor Nord Pool).

De prijsreferentie, berekend op basis van de uitgewisselde volumes via het continue intraday marktkoppelingsmechanisme XBID, steeg op gelijkaardige wijze als de day-aheadprijzen. Hoewel beide prijsindicatoren over langere periode sterk overeenkomen, zijn er korte en sterke verschillen waarneembaar tussen beiden op uurbasis: voor 2020 bedroegen de verschillen tussen intraday- en day-aheadprijzen zelden meer dan 20 €/MWh in eender welke richting.

De berekening van grensoverschrijdende capaciteit bleef, net zoals in het day-ahead tijdsbestek, een bijzonder aandachtspunt voor intraday-uitwisselingen. De toename in het aantal uren waarin geen capaciteit beschikbaar kan worden gemaakt, heeft een sterke impact op de mogelijkheid van marktdeelnemers om hun posities kort voor levering aan te passen, doordat ze niet over de grenzen heen handel kunnen drijven. Dit is, deels, een coördinatieprobleem tussen de betrokken TSB's: verzoeken van één TSB om de capaciteit te verhogen, worden vaak niet geaccepteerd door andere TSB's, doordat deze laatste de stromen van de toegenomen uitwisselingen in de intradaymarkt niet kunnen verwerken.

SOMMAIRE

Français

Les marchés belge et européen de l'électricité ont subi un choc profond et des évolutions remarquables en 2022. Selon de nombreux témoignages, les observations contenues dans le présent rapport annuel de surveillance dépassent de loin leur niveau normal. Ces observations montrent la réaction de tous les acteurs de la chaîne de valeur de l'électricité, des producteurs, des gestionnaires de réseau, des consommateurs et des négociants, aux changements radicaux de circonstances dans le secteur de l'électricité.

La **consommation totale d'électricité en** Belgique a atteint 81,1 TWh en 2022. Cela représente une baisse de 3,2% par rapport à 2021 (84,4 TWh). La consommation n'a été que légèrement supérieure aux 81,1 TWh exceptionnellement bas de 2020, résultant des mesures de confinement et de la contraction économique dans le contexte de la pandémie de Covid-19.

Dans le même temps, la charge du réseau de transport ne s'est élevée qu'à 64,0 TWh, soit une baisse vertigineuse de 9,7% par rapport aux 70,9 TWh de 2021. La baisse de la charge du réseau contraste avec l'augmentation significative de la production d'électricité non mesurée et consommée localement, par exemple via les installations solaires résidentielles ou la production éolienne connectée au réseau de distribution.

La consommation d'électricité reste fortement dépendante des conditions météorologiques. Conformément aux observations des années précédentes, des températures relativement basses et élevées entraînent une augmentation de la demande d'électricité, principalement à des fins de chauffage et de refroidissement. Cela conduit à confirmer la tendance saisonnière de la consommation d'électricité en 2022: des niveaux de consommation relativement faibles en été contre des niveaux plus élevés en hiver.

Pour la première fois, ce rapport tente de distinguer séparément les niveaux de consommation pour les grands consommateurs industriels et les petits ménages. Il est clair que différentes tendances peuvent être observées. Pour les grands consommateurs industriels, la demande d'électricité a considérablement augmenté au premier semestre 2022 par rapport aux années précédentes, mais a chuté à des niveaux (beaucoup) plus bas au second semestre, suite aux pics de prix extrêmement élevés de l'été dernier. La charge mensuelle au niveau de la distribution est, à l'exception de mars et d'avril, constamment inférieure aux niveaux des mêmes mois des années précédentes – encore une fois, en grande partie en raison de l'augmentation de la production d'électricité non mesurée et consommée localement.

La disponibilité des unités de **production d'électricité** a diminué en 2022, principalement en raison d'une disponibilité plus faible des groupes nucléaires et hydroélectriques. Les maintenances planifiées de Tihange 1 ont conduit à une baisse du taux de disponibilité des réacteurs nucléaires de 90% en 2021 à 76% en 2022.

Les volumes totaux d'électricité produite ont diminué de 3,7 % , passant de 93,4 TWh en 2021 à 89,9 TWh en 2022. La plus forte baisse par type de combustible a été observée pour les unités nucléaires (6,2 TWh), tandis que le solaire (+1,7 TWh), le gaz (+0,9 TWh) et l'éolien (+ 0,1 TWh) ont augmenté leur production.

L'intensité des émissions de gaz à effet de serre de la production d'électricité en Belgique a atteint 165 $gCO_{2\text{-eq}}$ /kWh en 2022, ce qui représente une diminution remarquable de 39,2% depuis 2000. Compte tenu de la volatilité du mix énergétique en Belgique, liée à la (non-)disponibilité des unités nucléaires, plusieurs augmentations temporaires et légères de l'intensité des émissions de gaz à effet de serre de la production belge ont été observées en 2015, 2018 et 2022.

Les flux transfrontaliers d'électricité sont restés un outil essentiel pour équilibrer l'offre et la demande d'électricité et faire en sorte que la production d'électricité tienne compte efficacement du signal de prix. Avec 19,2 TWh, les volumes totaux d'électricité exportés sont restés à un niveau très élevé en 2022, légèrement inférieurs aux valeurs record observées en 2021 (20,0 TWh). 2022 a donc été la quatrième année consécutive pendant laquelle la Belgique a été un exportateur net d'électricité, avec une position d'exportation nette de 6,3 TWh. Depuis début 2019, la Belgique affiche un solde structurel d'exportation net positif, indiquant que plus d'électricité a été exportée qu'importée, ce qui explique la différence positive entre la production et la consommation d'électricité.

Les prix observés sur les **marchés à terme** (long terme) pour la livraison en Belgique ont été constamment élevés avec quelques pics de prix tout au long de l'année 2022, après avoir commencé à augmenter à partir de mi-2021. Les prix pour livraison en 2023 (« Cal-23 ») ont été systématiquement supérieurs à 100 €/MWh tout au long de 2022, atteignant près de 800 €/MWh pour les contrats « baseload » vers la fin du mois d'août.

Dans le même temps, les prix pour livraison en 2022 étaient nettement inférieurs via les contrats à terme disponibles (par exemple, d'un à trois ans à l'avance) que par rapport au marché journalier pour la même période de livraison – les consommateurs ou les fournisseurs qui ont couvert leur position par des contrats à terme d'un an auraient payé près de 200 € / MWh de moins (avec des contrats Y+3 achetés en 2018) que sur le marché journalier. Les volumes déclarés sur les marchés à terme montrent que les volumes couverts pour livraison en 2022 ont été beaucoup plus élevés que les années précédentes, en particulier par rapport à 2020 et 2021.

Les ventes de capacités d'interconnexion par le biais de droits de transmission financiers, sous les formats de produits disponibles (droits de transmission physiques ou financiers) ont généré des revenus élevés pour Elia. Les prix de ces droits de transmission ont fortement augmenté, notamment pour les exportations vers la France et – pendant quelques mois – vers la Grande-Bretagne. Les prix payés lors de ces enchères ont parfois dépassé de loin les écarts de prix journaliers entre ces zones, générant un revenu net pour le gestionnaire de réseau de transport. Environ les trois quarts des volumes alloués lors des ventes aux enchères mensuelles et annuelles ont été vendus à des prix supérieurs à l'écart journalier pour la période de livraison correspondante, créant ainsi un revenu net pour Elia.

Un point d'attention particulier reste la suffisance des capacités de transmission transfrontalières offertes pour couvrir les besoins de couverture des acteurs du marché : les volumes demandés ont été, en 2022 comme les années précédentes, beaucoup plus élevés que les volumes offerts. En fonction de l'élasticité-prix de la demande pour les droits de transmission (non évaluée dans le présent rapport), augmenter les capacités mises à disposition lors des enchères à long terme profiterait à la fois aux acteurs du marché (permettant une meilleure couverture) et à Elia (générant des revenus plus élevés).

Les volumes d'électricité achetés et vendus sur **les marchés journaliers** ont poursuivi leur tendance à la hausse au cours des dernières années, atteignant 22,1 TWh, soit 27,0% de la consommation totale d'électricité en Belgique. Les parts de marché des deux NEMO actifs ont commencé à évoluer dans une direction plus équilibrée qu'historiquement: 79,2% pour EPEX SPOT contre 20,8% pour Nord Pool.

La combinaison des volumes achetés et vendus sur les deux NEMO en Belgique s'est traduite par une position d'exportation nette de +673 MWh/h pour toutes les heures de 2022. Cela représente une augmentation remarquable par rapport aux années précédentes, surtout compte tenu du départ du Royaume-Uni du marché intérieur de l'énergie, ce qui signifie que les volumes échangés sur l'interconnecteur Nemo Link ne sont pas inclus ici et sont comptabilisés séparément.

Les prix journaliers en Belgique ont augmenté bien au-delà de leurs niveaux historiques. Le prix moyen en 2022 (244,5 €/MWh) est plus de deux fois supérieur à la valeur de 2021 (104,1 €/MWh) et près de six fois supérieur à la moyenne historique entre 2015 et 2020 (42,1 €/MWh). Trois périodes distinctes avec des pics de prix courts mais soutenus ont été observées tout au long de l'année : début mars, fin août et début à mi-décembre.

Dans le même temps, la convergence des prix a diminué, tant au niveau européen qu'au niveau individuel, frontière à frontière. Cette baisse s'est accompagnée d'une augmentation des écarts de prix observés entre les zones d'enchères couplées. La survenance de divergences de prix, provoquée par l'incapacité du réseau de transport à permettre les échanges requis pour faire converger les prix, est particulièrement préoccupante dans le contexte des congestions observées et des faibles marges pour les échanges transfrontaliers.

L'introduction réussie, en juin 2022, du projet de couplage du marché journalier dans la région Core peut être considérée comme l'une des étapes les plus importantes du couplage du marché européen de la dernière décennie. Malgré le succès opérationnel, certaines lacunes importantes peuvent être observées dans ce rapport, notamment en ce qui concerne l'application structurelle des contraintes d'allocation et les ajustements de validation individuels. Ces mécanismes entravent la capacité du mécanisme fondé sur les flux à exploiter pleinement son potentiel : en particulier, les faibles marges disponibles pour les échanges entre zones continuent de poser problème, après de nombreuses années.

Sur les **marchés intrajournaliers**, les volumes échangés sont passés de 2,9 TWh en 2021 à 4,4 TWh en 2022. Malgré la concurrence entre les bourses de l'électricité, les parts de marché sont plus faussées en faveur de l'opérateur historique que sur le marché journalier (89,3 % pour EPEX SPOT; 10,7 % pour Nord Pool).

Les prix de référence, calculés sur la base des volumes échangés par le biais du mécanisme continu de couplage intrajournalier XBID, ont augmenté d'une manière très similaire aux prix journaliers. Bien qu'ils correspondent étroitement aux niveaux de prix sur des périodes plus longues, des écarts très courts et importants peuvent être observés entre les deux indices de prix sur une base horaire : avant 2020, ces écarts dépassaient rarement 20 €/MWh dans un sens ou dans l'autre.

Le calcul de la capacité disponible entre zones reste, comme dans le délai journalier, un point d'attention particulier pour les échanges intrajournaliers. L'augmentation du nombre d'heures pendant lesquelles aucune capacité ne peut être mise à disposition a de graves répercussions sur la capacité des acteurs du marché à équilibrer leur position en temps réel, en les empêchant de commercer au-delà des frontières. Il s'agit, en partie, d'un problème de coordination entre les GRT concerné s: les demandes d'augmentation d'un GRT ne sont souvent pas acceptées par un autre, en raison de l'incapacité de ce dernier à prendre en compte les flux provenant des échanges accrus dans la période intrajournalière.

INTRODUCTION

In this study, the COMMISSION FOR ELECTRICITY AND GAS REGULATION (“CREG”) presents its findings with regards to the monitoring of the functioning and price evolution of the Belgian wholesale markets for electricity. The focus of this study is the evolution of the Belgian electricity markets in 2022. Where available, historic data dating back to 2015 are presented.

This study is divided in 8 different chapters:

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

The Board of Directors of the CREG approved this study at its meeting held on 1 June 2023.

1. CONSUMPTION

1. The total load and grid load on the transmission network both decreased in 2022 compared to 2021. After a rebound in electricity consumption in 2021 following the Covid-19 crisis, the total and grid loads dropped again to reach very low levels. This can mainly be explained by the very high electricity prices that have been observed throughout the year (see also sections 4 and 5).

2. As illustrated on Figure 1-1, the total load amounted to 81,7 TWh in 2022 (i.e. a 3,2% decrease compared to 2021). The total load in 2022 almost dropped as low as 2020 level, which was an exceptional year because of the Covid-19 pandemic.

3. The load on the transmission network amounted only to 64,0 TWh in 2022, which represents a significant decrease of 9,7% compared to the previous year. The grid load in 2022 was even lower than in 2020, which suggest that it is very sensitive to electricity prices. This decline in the grid load contrasts with the significant increase in unmetered, locally consumed electricity generation, which is not included in the transmission network load but whose estimates are included in the total load. Still, the rise in unmetered, locally consumed electricity (+4,2 TWh in 2022 compared to 2021) was not enough to compensate the drop in the grid load (-6,9 TWh in 2022 vs. 2021), thus explaining the decrease in the total load.

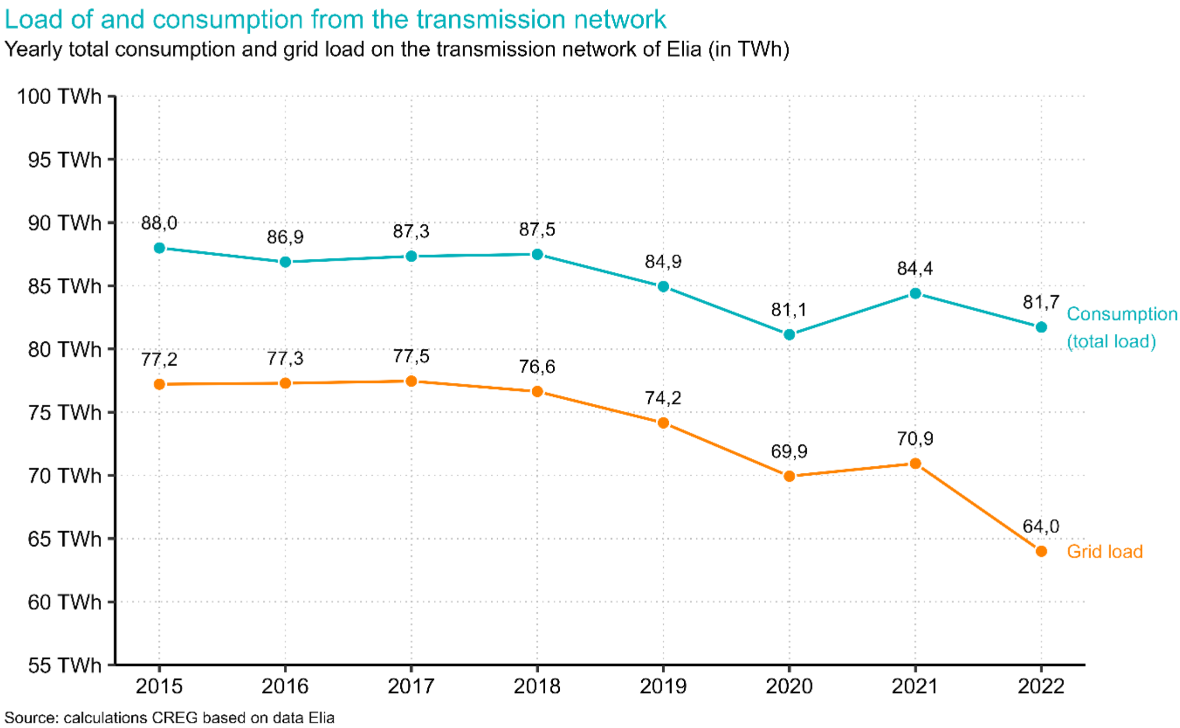


Figure 1-1 Load of and consumption from the transmission network

1.1. TOTAL LOAD

4. The evolution of the total electricity load in Belgium and neighboring countries for the period 2015-2022 is illustrated in Figure 1-2. Similarly to Belgium, one can observe a downward trend over the past years in the total electricity load of other European countries. Austria appears to be the country with the most stable load over the considered period.

5. In 2022, the total electricity load of all considered countries decreased compared to 2021. For Germany, France and the Netherlands, it even reached levels as low as during the Covid-19 crisis (even lower in the case of the Netherlands). Austria experienced a limited reduction compared to other countries (-2,5% compared to 2021). On the other side, the Netherlands is the country with the largest decrease in its total load in 2022 (-6,0% compared to 2021). This is the only country whose total load declined for three years in a row.

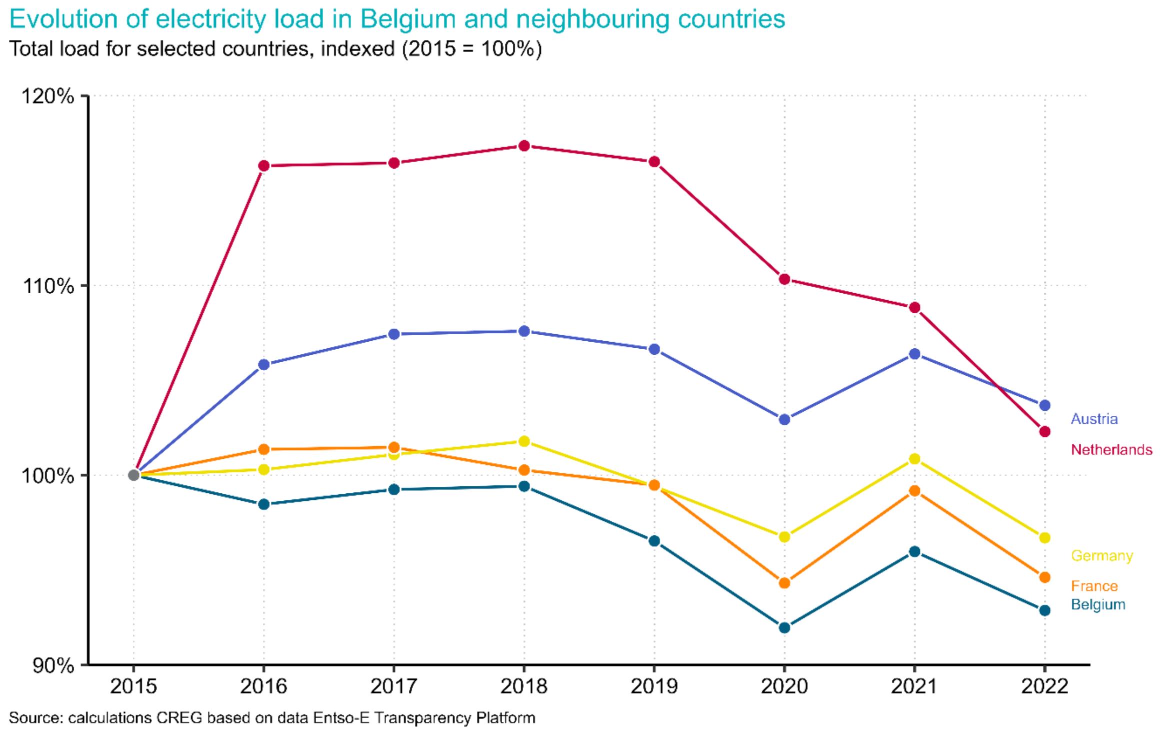


Figure 1-2 Evolution of electricity load in Belgium and neighbouring countries

6. Belgium's total electricity load in 2022 amounted to 81,7 TWh, i.e. a 3,2% decrease compared to 2021 (see Figure 1-3 and Figure 1-4). As far as other European countries are concerned, the total load amounted to 483,7 TWh in Germany (- 4,1% compared to 2021), 443,1 TWh in France (-4,9% compared to 2021), 100,0 TWh in the Netherlands (-6,0%) and 61,3 TWh in Austria (-2,5%).

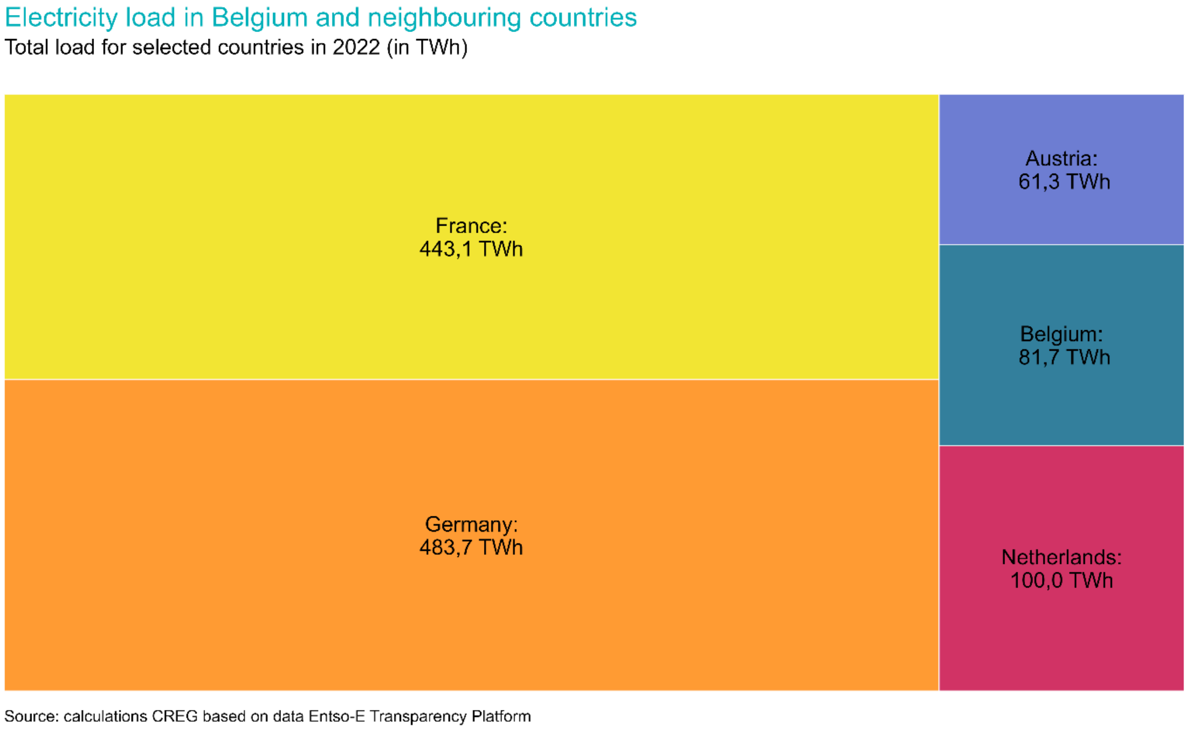


Figure 1-3 Electricity load in Belgium and neighbouring countries

7. Considered European countries were impacted differently by the energy crisis and the high electricity prices in 2022. Indeed, the impact seems to have been rather limited in Austria and Belgium compared to the other countries which experienced a drop comprised between, -4.1% and -6.0%.

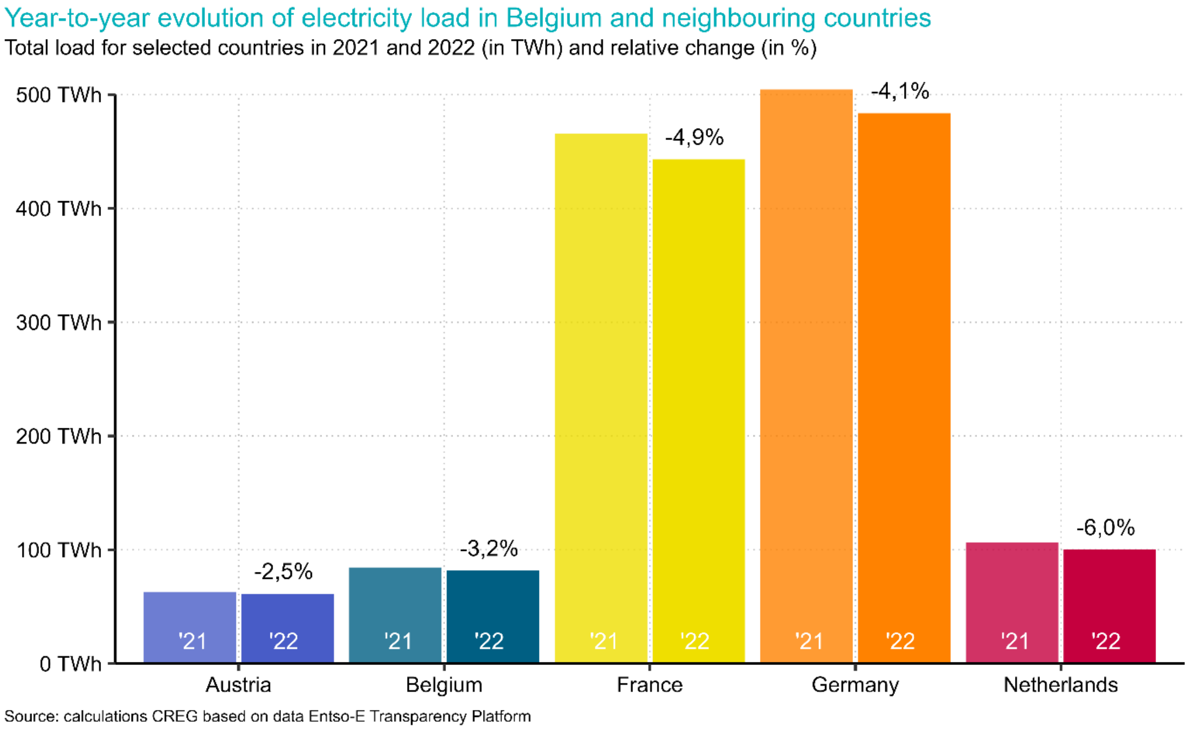


Figure 1-4 Year-to-year evolution of electricity load in Belgium and neighbouring countries

8. Figure 1-5 shows in detail the evolution of the electricity peak demand in Belgium over the period 2015-2022. The figure illustrates the total load at five different levels of the yearly load duration curves :

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

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

10. Similarly to the total load, the maximum and minimum load as well as in the load at hours 100, 200 and 400 decreased in 2022 compared to 2021. In particular, the maximum load has reached its lowest level since 2015 with only 13.234 MW. It decreased by 2,4% between 2021 and 2022 while the minimum load decreased by 6,0% between those two years.

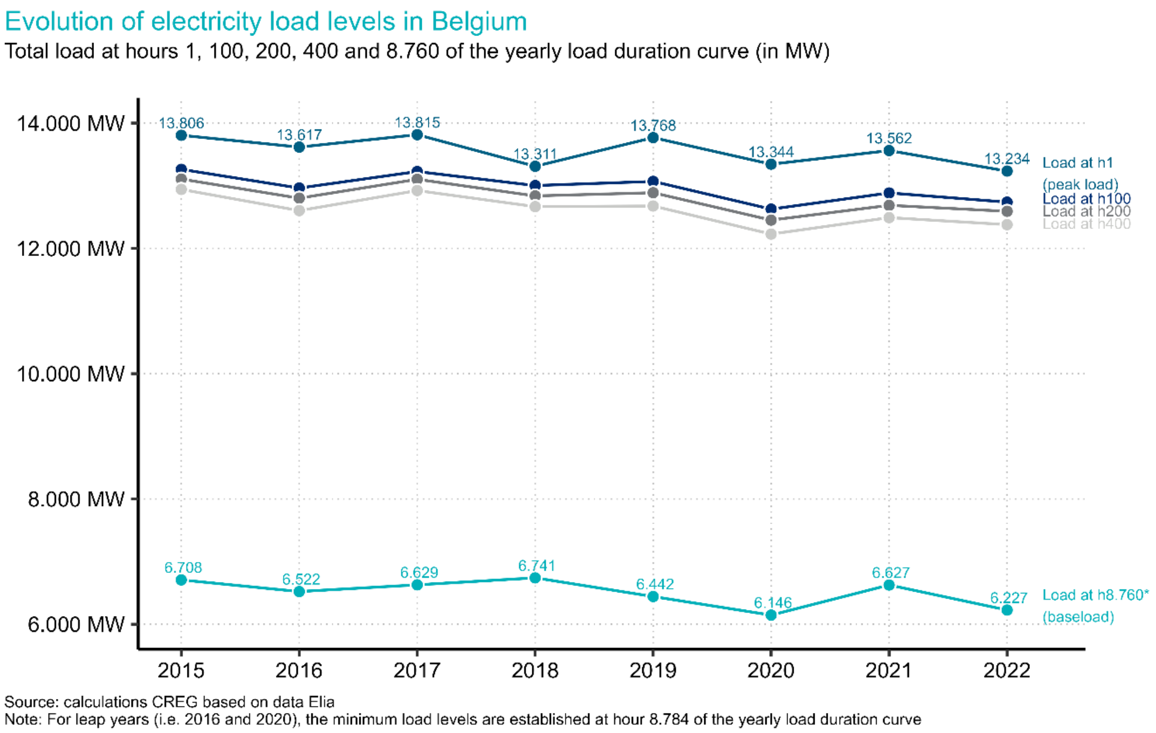


Figure 1-5 Evolution of electricity load levels in Belgium

1.2. TEMPERATURE SENSITIVITY OF ELECTRICITY CONSUMPTION

11. Figure 1-6 illustrates the monthly average total Belgian load for the period 2015-2022 (be aware that the ordinate axis starts at 7.000 MW). The shape of the curves shows the temperature sensitivity of electricity consumption: in winter, the average total load is significantly higher than during the summer months (up to 2.000 MW difference).

12. This figure also illustrates the impact of the energy crisis on Belgium's total electricity load in 2022. While the load in 2021 almost returned to levels similar to the 2015-2019 period, mainly driven by the economic rebound following the Covid-19 crisis and a lower yearly average temperature in 2021 compared to 2020[1] (see also Figure 1-7), it dropped in 2022 below 2020 averages for the months of August to December.

13. Several factors can explain these very low monthly averages for 2022 compared to 2021. Firstly, 2022 was a very warm year : the yearly average temperature was 12,2 °C in 2022, while it was only 10,7 °C in 2021, thus equaling the record of 2020. Except for the months of April, September and December, the average monthly temperature in 2022 was higher than the seasonal norms calculated on the period 1991-2020[2].

14. In the winter months, higher temperatures translate into a lower electricity consumption because of a lower need for turning on electric heaters to warm buildings. On the contrary, in summer, higher temperatures usually translates into an increase in electricity consumption which can be explained by the use of air conditioning to cool down interiors (this thermosensitivity effect of electricity consumption is illustrated on Figure 1-7). However, even though July and August 2022 were significantly warmer than in 2021, the monthly average total load for those two months remained lower than in 2021.

15. This unusual observation can be explained by another factor which had a significant impact of the electricity load: the high electricity price levels observed throughout the year. As described later in section 5.2 on prices observed on the day-ahead markets, there were in particular three periods with major price peaks in 2022 (see also Figure 5-7 on day-ahead prices in 2022 in Belgium and neighbouring countries): early-March, end of August and early-mid-December. Despite lower temperatures in March and April 2021 than in March and April 2022[3], it can be observed that the average monthly total load was lower in both months of 2022 compared to 2021. Electricity consumption thus decreased as a consequence of high energy prices.

16. Finally, the monthly average total load was particularly low in October 2022. This can be explained by the very mild temperatures as well as further impact of high electricity prices (and in particular the price peak of end-August with highest electricity prices ever observed since 2015). Nevertheless, the translation of high prices on electricity consumption is not immediate because most electricity consumers have contracts with monthly payments and not all consumers have contracts with variable prices.

[1] 2020 is the warmest year on record

[2] Institut Royal Météorologique

[3] One could then expect that the electricity load would be higher in April 2021 than in April 2022.

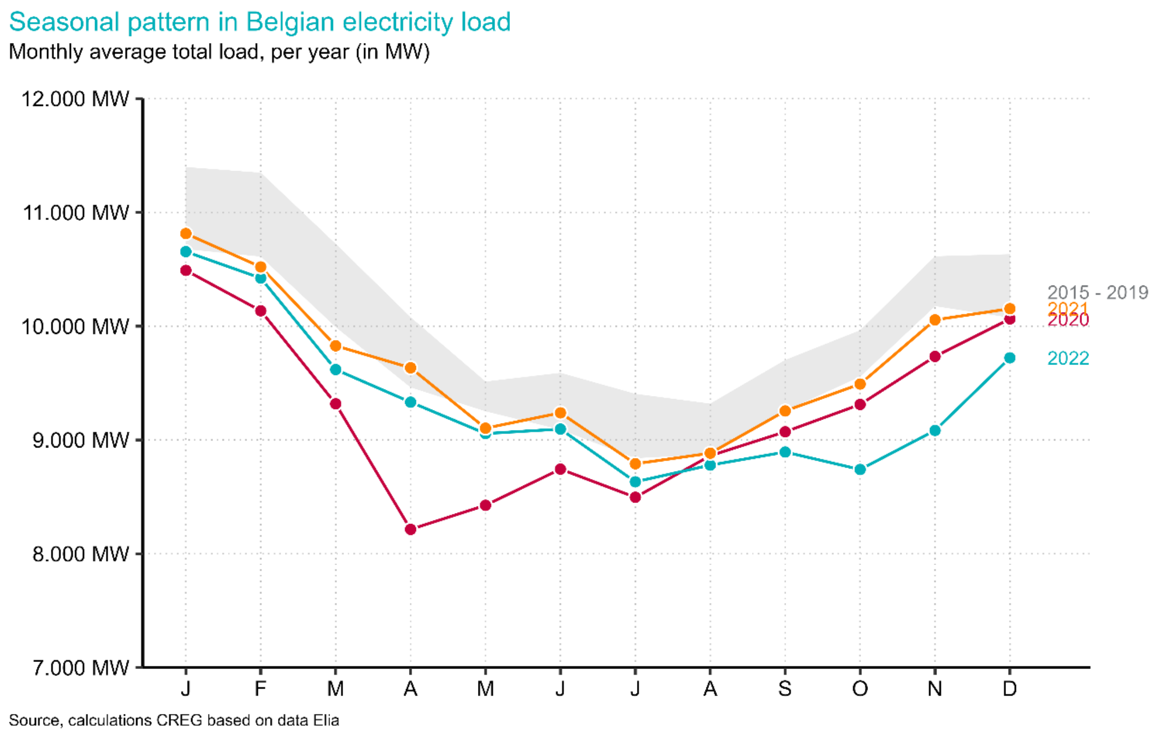


Figure 1-6 Seasonal pattern in Belgian electricity load

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

18. The differences in the relationship between 2020, 2021 and 2022 can be explained by the differences in yearly average temperature. As highlighted before 2020 and 2022 are the warmest years on record (with a yearly average temperature of 12.2°C). Though, some differences can be observed between the two years: temperatures in 2022 were much more extreme in the cold (but still, not as cold as in 2021) and slightly more extreme in the warm. Both trend lines for 2020 and 2022 show an upward trend at the right side of the figure (compared to 2021), indicating an increase in temperature and consequently, in load levels.

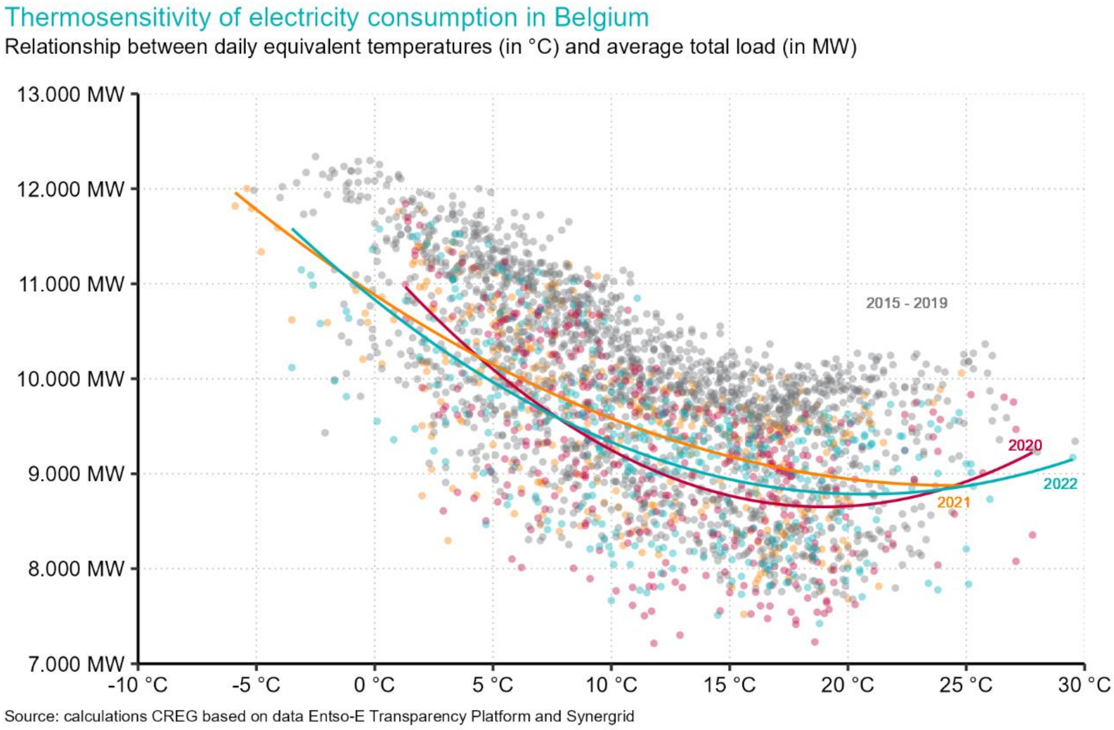


Figure 1-7 Thermosensitivity of electricity consumption in Belgium

1.3. INDUSTRY AND HOUSEHOLD CONSUMPTION

19. Figure 1-8 illustrates the evolution of the monthly average industrial load in Belgium for the period 2015-2022. The grey area represents the 2015-2019 period. The industrial load corresponds to the offtake from the Elia transmission network of industrial clients connected this part of the grid. Thus, it does not include the electricity load of industrial clients connected to the distribution network, which usually are smaller industries with a more limited electricity consumption. This is part of the distribution load is depicted in Figure 1-9.

20. One remarkable fact on the year 2022 is that the industrial load and the distribution load did not follow the same evolution. This suggests that high energy prices did not have the same impact across the several types of consumers.

21. As far as the first half of the year is concerned, opposite trends can even be observed. On the one side, the industrial load in 2022 was higher than in 2021 for the months of January to June. Despite significantly higher electricity prices during this period than in 2021, the industrial load reached levels far above 2020 and 2021. This trend totally reversed from July when the industrial load eventually dropped below 2021 levels (with the exception of the month of November). This can be partly explained by the very high prices observed in August 2022 and the delayed reaction of industrial consumers to the price signal.

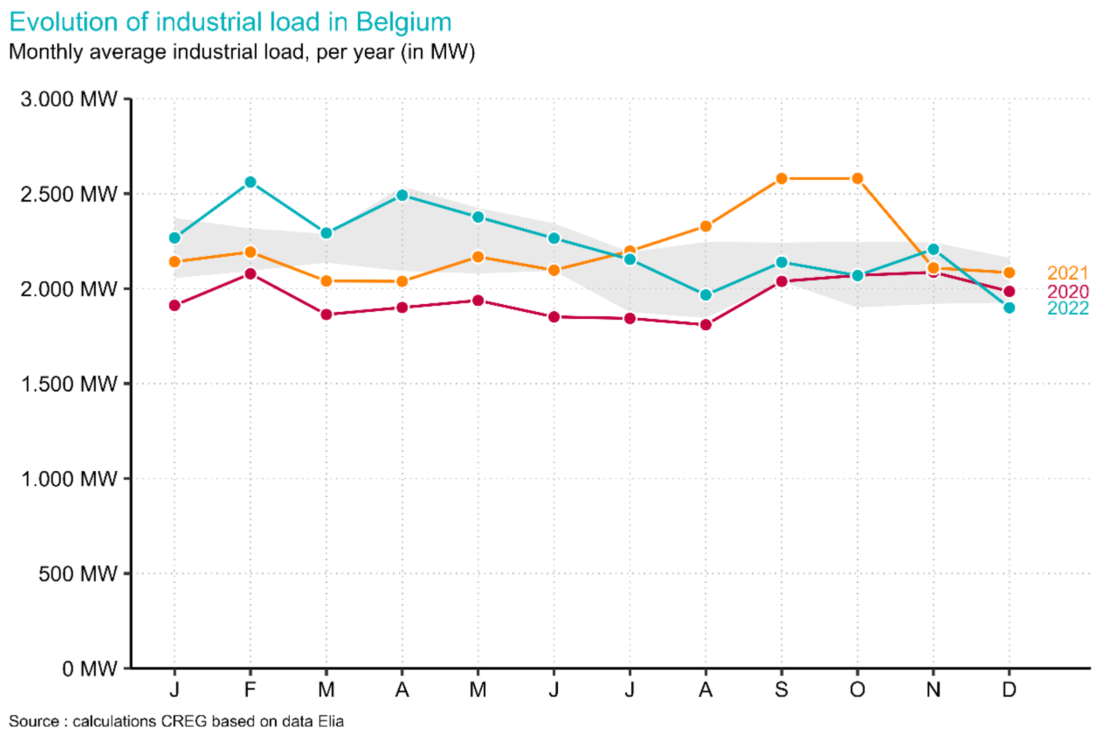


Figure 1-8 Evolution of industrial load in Belgium

22. On the other side, the distribution load in 2022 remained below 2021 levels over the whole year, and even reached levels below monthly averages of 2020. This clearly illustrates the sensitivity of electricity consumption to high prices.

23. One can also notice that the load at distribution level is much more sensitive to temperatures than the industrial load. A shape similar to the one of the total load can be observed in Figure 1-8 , illustrating seasonal patterns of electricity consumption. The industrial load represents the electricity consumption of big industrial clients, i.e. industries which use electricity all year long for their industrial processes. Their electricity consumption is thus logically much less sensitive to temperatures. One could actually expect that electricity consumption of these industries is more sensitive to electricity prices but data for the first half of 2022 do not seem to confirm this.

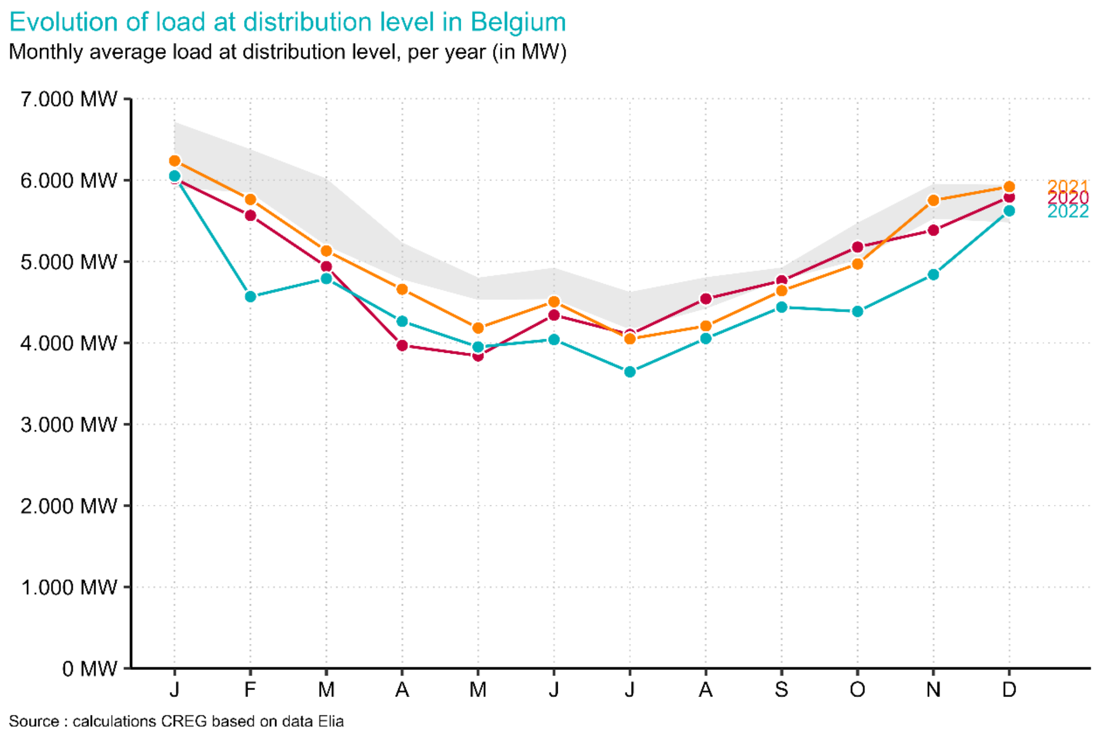


Figure 1-9 Evolution of load at distribution level in Belgium

24. Finally, one can also observe that the sum of the industrial load and the distribution load does not match the total electricity load (see Figure 1-1). This difference is to be found in unmetered, locally consumed electricity generation, which is not measured on the transmission network but whose estimates are included in the total load.

2. PRODUCTION

2.1. INSTALLED CAPACITY

25. In previous editions of this study, the CREG published several figures on the evolution of installed capacity in Belgium. These figures were based on data from ENTSO-E Transparency platform on which multiple data and information on electricity generation, transportation and consumption are published. As far as installed capacity in Belgium is concerned, Elia is the data provider of these data on the ENTSO-E transparency platform.

26. However, the data on installed capacity in Belgium, as available on the platform at the time of writing of this study, include some anomalies or do not correspond to the detailed description given on the website of Entso-E Transparency platform. For this reason, data on solar and wind (seemingly not correct in the Entso-E Transparency Platform) have been obtained from IRENA.[4] Data on nuclear capacity has been manually corrected from the values obtained in the Entso-E Transparency Platform, given the closure of the Doel 3 unit (- 1.006 MW in 2022 compared to previous years.).

27. Based on these corrections, the CREG has established the total generation capacity in Belgium to be a little above 27 GW at the end of 2022. Figure 2-1 Installed generation capacity in Belgium. Figure 2-1 shows the evolution per category – mainly the increase in installed solar capacity, reaching 6.898 MW in 2022, is remarkable.

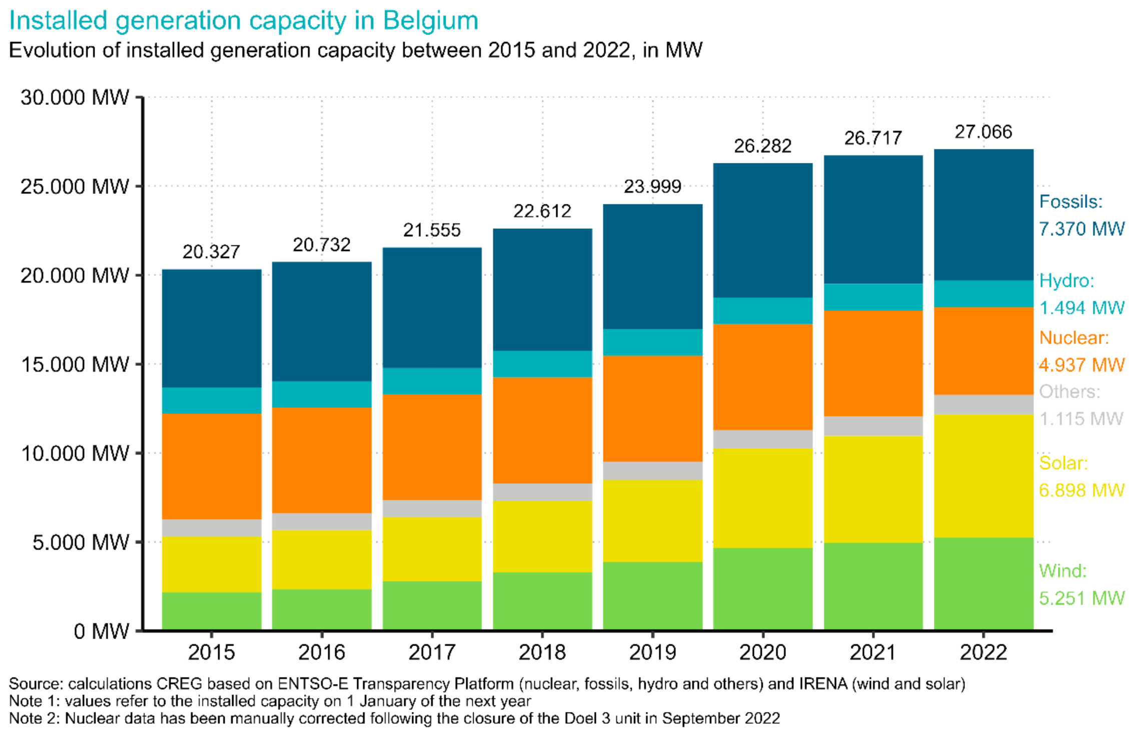


Figure 2-1 Installed generation capacity in Belgium

[4] The International Renewable Energy Agency IRENA publishes a yearly overview of renewable installed capacity, based on questionnaires for its members. The data on installed wind and solar capacity seem more reliable than the ones provided to the Entso-E Transparency Platform.

28. Given the importance of correct data on installed generation capacity, the CREG will reach out to Elia to correct and publish accurate numbers on its own and Entso-E's platforms.

2.2. AVAILABILITY OF GENERATION ASSETS

29. Figure 2-2 illustrates the full availability rate of generation units by fuel type in 2022. The full availability rate is defined as the number of days of full availability throughout the year, or in other words, the number of days in which no outages occurred (forced and planned outages are considered here). Each small dot represents a generation unit, while the bigger dots represent the average full availability rate by fuel type.

30. In 2022, generation units were significantly less available than in 2021. A considerable drop in the full availability rate can be observed for the nuclear and hydro units. The average full availability rate of nuclear units decreased from 90% in 2021 to 76% in 2022 and can mainly be explained by the planned maintenances of Tihange 1[5]. As far as hydro units are concerned, the significant decrease in the full availability rate can be explained by the low availability of Coo and Plate-Taille power plants: Coo I and Coo II were fully available for 25% and 19% of the time in 2022, respectively, while Plate-Taille was only available for 18% of the time in 2022.

31. On the other hand, the full availability rate increased for natural gas and liquid fuel units as well as for generation units of type 'Other'[6] (from 89%, 94% and 91% in 2021 to 86%, 90% and 96% in 2022, respectively).

32. The availability rate of individual units or per fuel type does not necessarily reflect the utilisation rate. The latter compares the generated energy to the installed capacity (i.e. the so-called capacity factor). It is possible that, while a unit is available in 100% of the time (as no outage occurs), its actual output is well below the theoretically possible output (which corresponds to the full capacity multiplied by the time period).

[5] These numbers are adjusted to take into account the closure of Doel 3 in September 2022.

[6] This category includes units which use waste recycle as fuel.

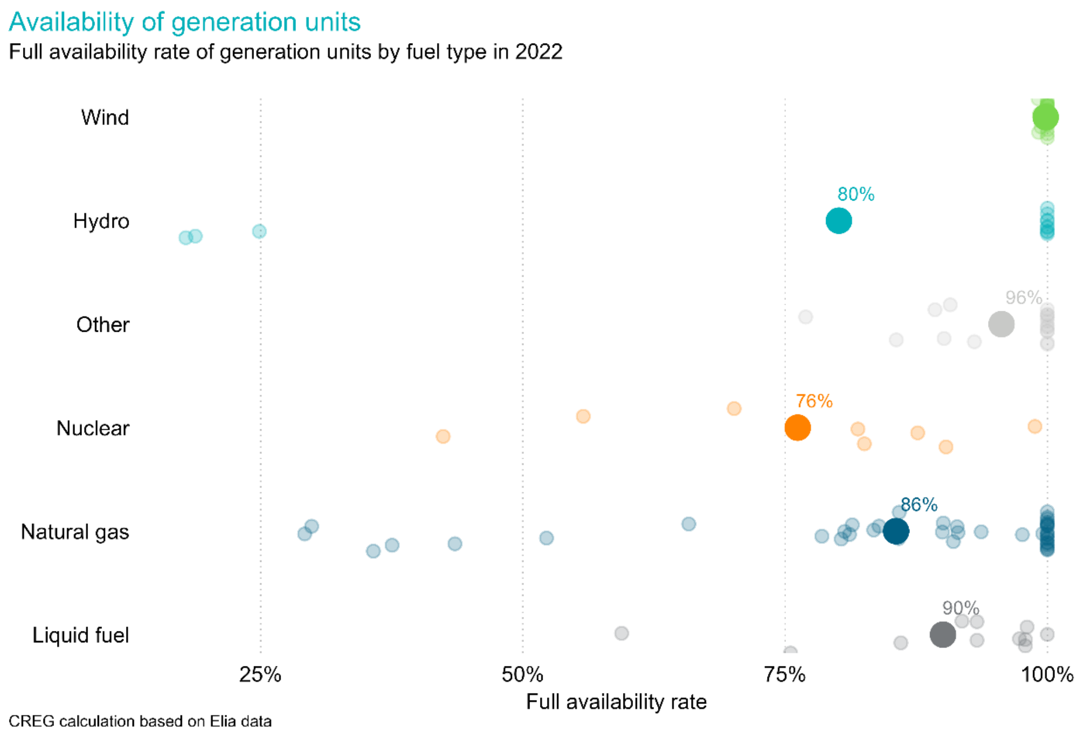


Figure 2-2 Availability of generation units

2.3. ELECTRICITY GENERATION

33. Total electricity generation reached 89,9 TWh in 2022, as shown in Figure 2-3. This represents a decrease of 3,5 TWh or 3,7% compared to 2021, which was a record year for electricity generation, but should not deflect the fact that Belgian power plants still produced a high amount of electricity compared to previous years. Despite the closure of Doel 3 in October 2022, electricity generation by nuclear units remained high with 41,7 TWh of generated electricity (see also Figure 2-6).

34. Similarly to 2021, the high amount of electricity generated by Belgian power plants, combined to the relative decrease in electricity demand (see previous chapter), resulted in high electricity exports to neighboring countries, especially to France (10,7 TWh in 2022 because of the limited availability of French nuclear power plants) and to Great-Britain (3,3 TWh in 2022). The total physical export of electricity from Belgium reached 19,2 TWh in 2022 (see also section 0).

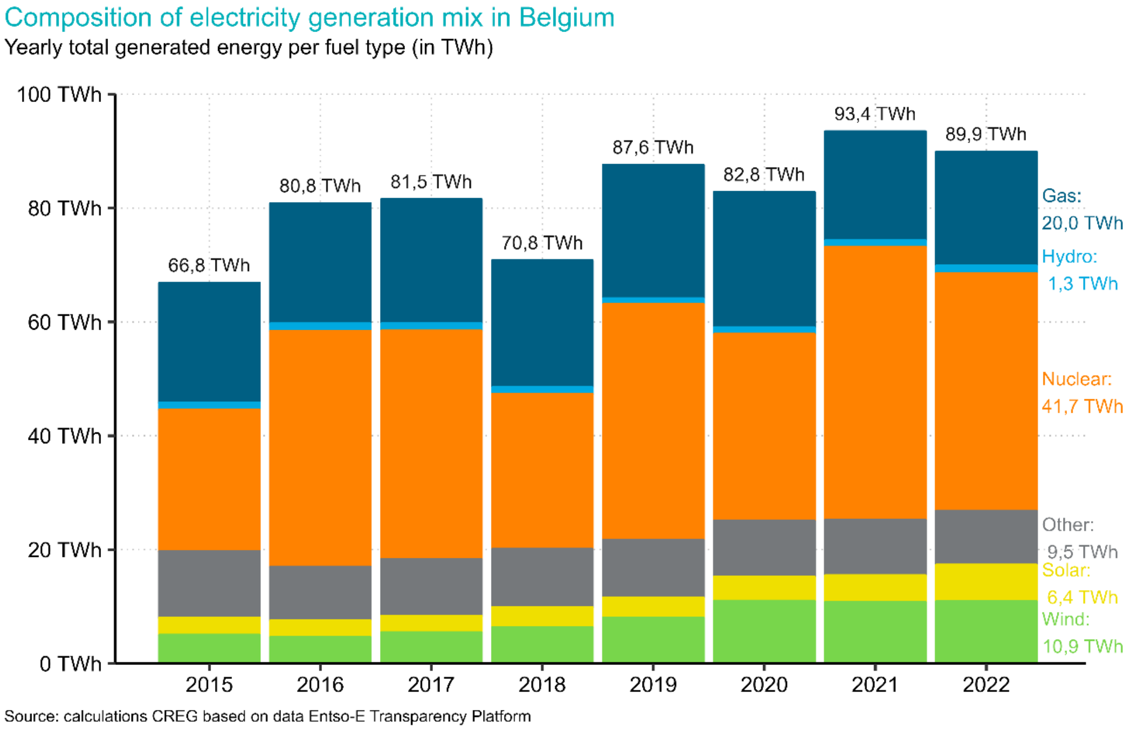


Figure 2-3 Composition of electricity generation mix in Belgium

35. Figure 2-4 shows the annual fluctuations in electricity generation by technology. To visualize the evolution by generation technology in 2022 compared to the previous year, this figure illustrates, step by step, how the total generation of 93,4 TWh in 2021 evolved toward a generation of 89,9 TWh in 2022.

36. The main driver for the decrease in electricity generation is the decline in nuclear generation: it decreased by 6,2 TWh in 2022 compared to 2021. This decrease can mainly be explained by the closure of the Doel 3 reactor in October 2022 and by the limited availability of Tihange 1 and 2. In contrast, solar generation increased by 1,7 TWh or 36% compared to 2021 (to 6,4 TWh, the highest amount of electricity ever generated in Belgium by solar panels). Gas-fired generation increased only by 0,9 TWh (but still remaining below level observed in previous years, see also Figure 2-3) while wind generation remained stable between 2021 and 2022 (+0,1 TWh to reach 10,9 TWh in 2022). Regarding generation from wind farms, the very limited increase in generation, despite the increase in installed capacity, is due to relatively unfavourable weather conditions which had a negative impact on the load factor of this technology. The considerable increase in solar generation is mainly due to the increase in installed capacity.

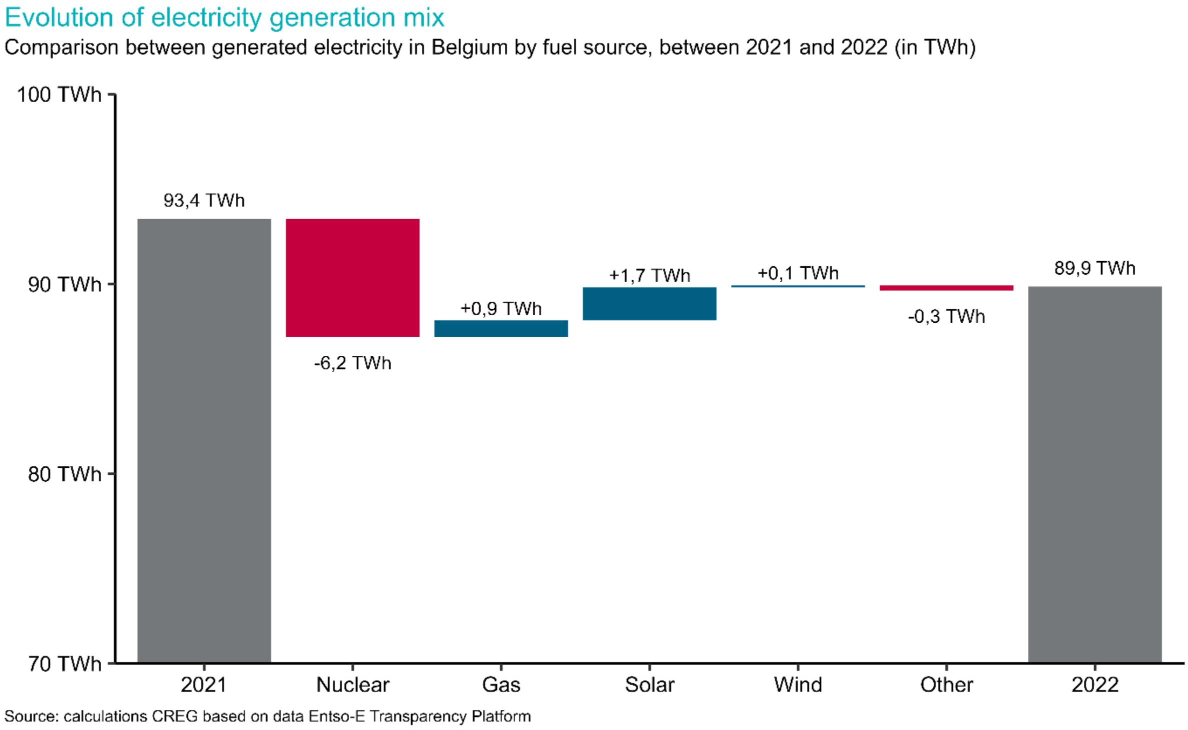


Figure 2-4 Evolution of electricity generation mix

37. Figure 2-5 shows the evolution of electricity generation per fuel type between 2015 and 2022. One can rapidly notice that wind and solar are the technologies that register the most striking evolution over the period. This is due to the increase in the installed capacity of these two renewable sources. Though, wind generation remained rather stable over the last three years despite an increase in installed capacity of onshore wind (+579 MW between 2020 and 2022, according to IRENA data).

38. As far as gas-fired generation is concerned, the increasing trend totally reversed in 2021. After having constantly risen six years in a row, electricity generation from gas-fired power plants dropped significantly in 2021. It rose slightly in 2022 but did not reach historical levels back. This decrease in 2021 can be explained by the high availability of nuclear power plants, thus reducing the need for electricity generation from gas units.

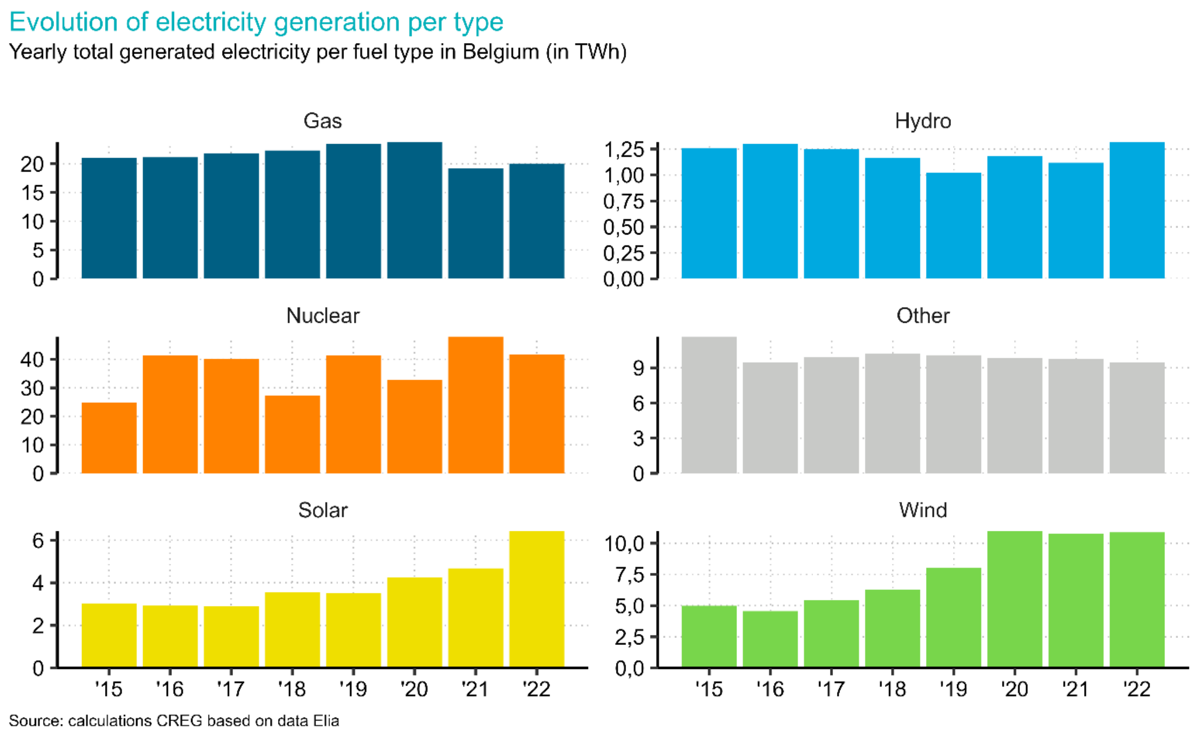


Figure 2-5 Evolution of electricity generation per fuel type

39. Nuclear electricity generation is quite fluctuating over the years, reflecting the availability of the various reactors. In 2015 and 2018, the availability of Belgium's nuclear power plants was limited, which explains the low levels of electricity generation. In 2020, electricity generation from nuclear plants had to be limited because of the reduced demand for electricity as a consequence of the lockdown measures. With the closure of Doel 3, it can be expected that nuclear electricity generation will decrease in the coming years.

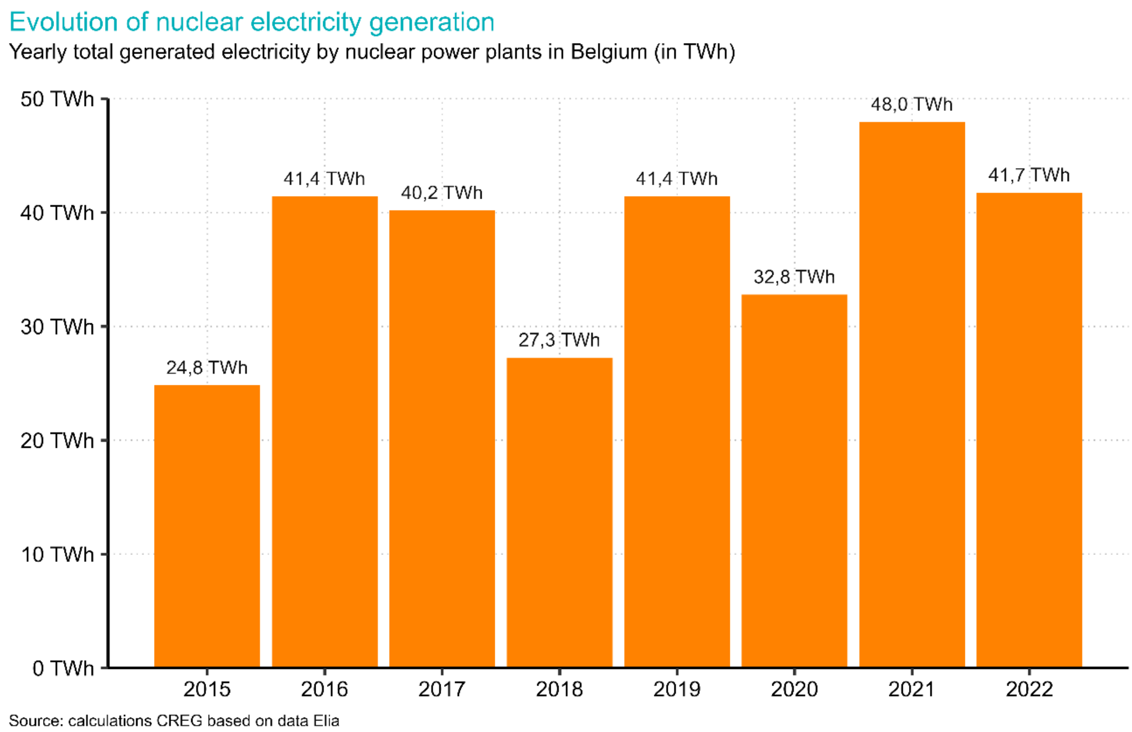


Figure 2-6 Evolution of nuclear electricity generation

40. Figure 2-7 illustrates the seasonal complementarity of the wind and solar electricity generation. One interesting observation is that electricity generation from wind and solar varies in opposing but complementary manners: during winter, wind conditions are pretty good and sunlight conditions are rather bad, this explaining high levels of wind generation and low levels of solar generation. On the other hand, wind conditions are less favorable in spring and summer while sunlight conditions considerably improve, resulting in higher levels of solar generation and lower wind generation. In short, wind generation is high when solar generation is low and vice versa.

41. 2022 was a record year for both wind and solar electricity generation. In February 2022, 1.684 GWh of electricity were generated from wind farms and 936 GWh of electricity were generated from solar in July 2022.

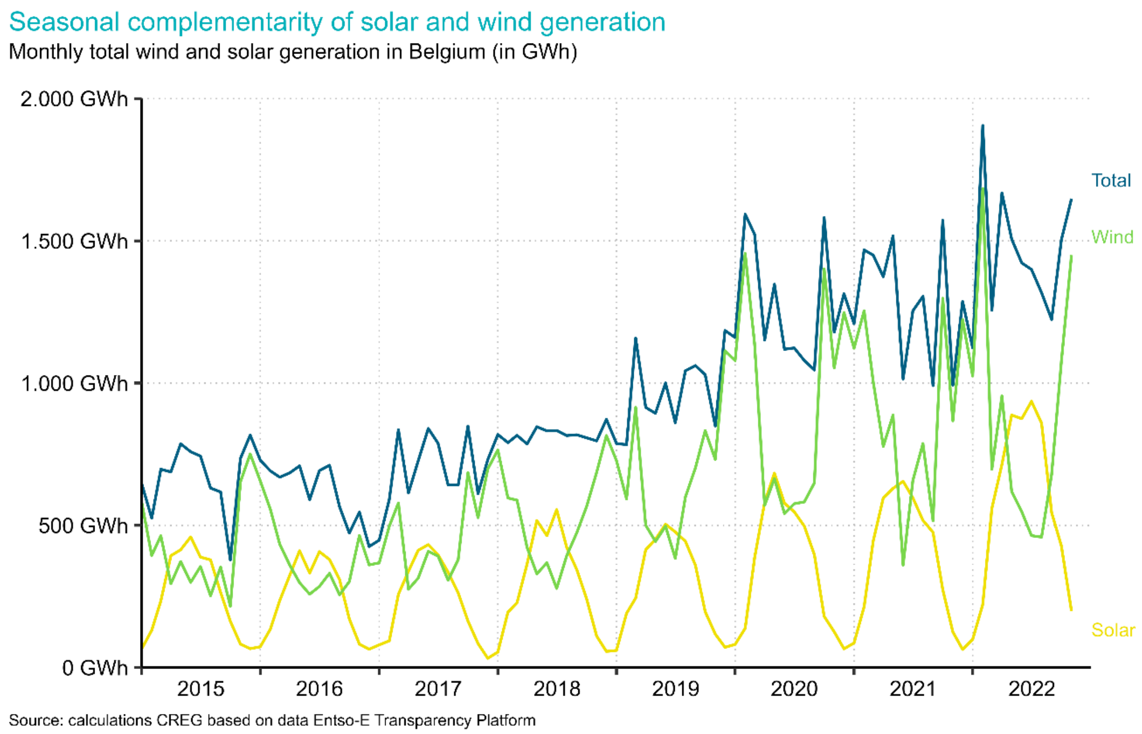


Figure 2-7 Seasonal complementarity of solar and wind generation

2.4. CAPACITY FACTOR

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

43. Though, data on installed capacity are necessary to calculate the capacity factor. As explained in section 2.1, the CREG does not have access to such data for 2022 and is therefore not able to publish figures on capacity factor in this year's edition of the study.

2.5. CARBON INTENSITY OF ELECTRICITY GENERATION

44. In previous editions of this study, the CREG published the evolution of greenhouse gas emission intensity of electricity production in Belgium and neighbouring countries based on data from the European Environment Agency (EEA) which computes every year the greenhouse gas emission intensity of electricity generation for all European countries7.

45. However, the latest data on greenhouse gas emission intensity of electricity generation released by the EEA in October 2022 and covering the period from 1990 to 2021, include some anomalies in the data for Belgium. Without the means to verify these data, the CREG decided to not use data from the EEA in this year's edition and eventually to rely on data from Our World in Data.

[7] https://www.eea.europa.eu/ims/greenhouse-gas-emission-intensity-of-1

46. Figure 2-8 illustrates the evolution of greenhouse gas emission intensity of electricity production in Belgium and neighboring countries between 2000 and 2022. Greenhouse gas emission intensity of electricity decreased significantly over that period for all selected countries. The United Kingdom is the country recording the sharpest decrease (from 483 gCO2eq/kWh in 2000 to 268 gCO2eq/kWh in 2021[8]). The drop is particularly impressive between 2012 and 2021 as it was almost divided by two.

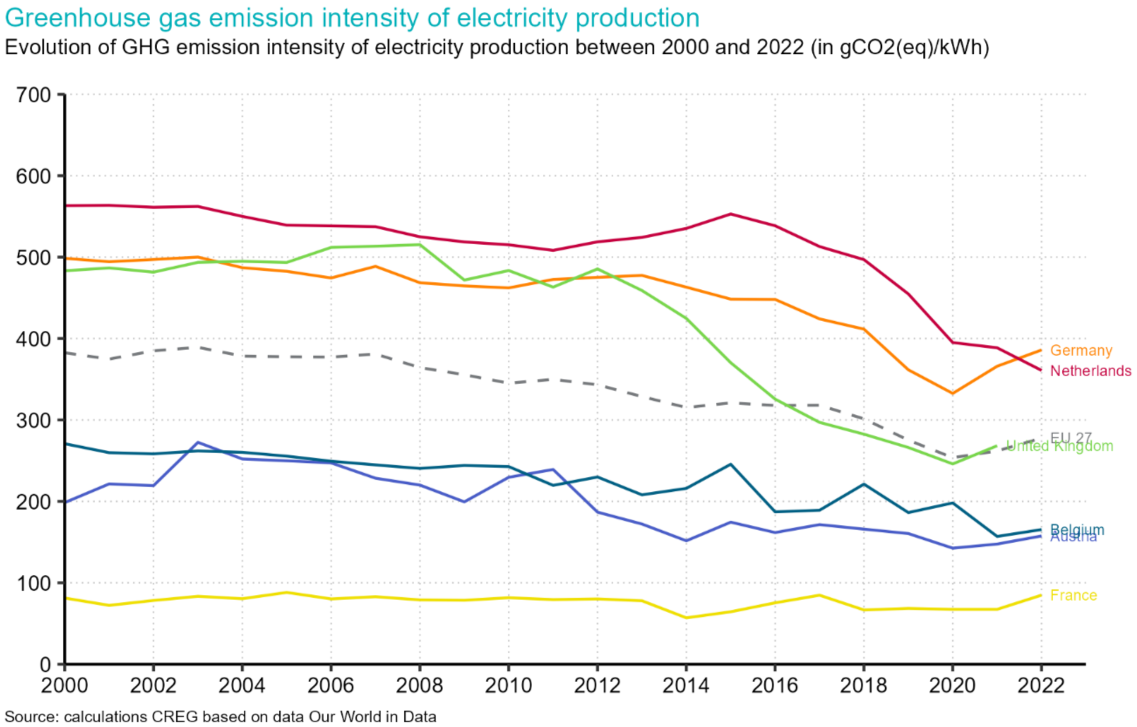


Figure 2-8 Greenhouse gas emission intensity of electricity production

47. Belgium's greenhouse gas emission intensity of electricity production decreased from 271 gCO2eq/kWh in 2000 to 165 gCO2eq/kWh in 2022, i.e. a reduction of 39,1%. The greenhouse gas emission intensity of electricity production is highly dependent on the energy mix used to produce electricity. The downward trend observed over the considered period can be explained by the gradual phase-out of coal (since 2016, no more electricity is generated by coal-fired power plants in Belgium) and by the growth of renewable sources (solar and wind) in the electricity production mix. Recently, surges in the greenhouse gas emission intensity of the production mix in Belgium were witnessed in 2015 and 2018, when the reduced nuclear availability and generation had to be compensated by an increase in electricity generation from fossil fuel sources. On the contrary, the GHG intensity of electricity production significantly decreased between 2020 and 2021 thanks to the high availability of nuclear units in 2021.

48. France is the only country with a GHG intensity below 100 gCO2eq/kWh (85 gCO2eq/kWh in 2022) and whose GHG intensity did not evolve significantly over the considered period. This can be explained by the highly decarbonised electricity generation mix of the country, mainly based on nuclear.

[8] 2022 data re not available for the United Kingdom

49. Despite a considerable reduction in the past seven years, electricity production in the Netherlands and Germany remains highly carbon-intensive and significantly above the EU-27 average. In 2022, GHG intensity of electricity generation was as high as 186 gCO2eq/kWh for Germany and 361 gCO2eq/kWh for the Netherlands. A remarkable fact is that the Netherlands are the only country recording a decrease in its GHG intensity between 2021 and 2022 (-7.2% between the two years).

3. CROSS-BORDER FLOWS

50. Belgium has physical interconnections with 5 other countries: France, the Netherlands, Germany, the United Kingdom and Luxembourg.[9] The High-Voltage Direct Current (HVDC) connections with the United Kingdom (early 2019) and Germany (end of 2020) are relatively new. The flows and net positions observed on the borders of Belgium and its neighbours are the result of the import and export nominations for exchanges in the long-term, day-ahead and intraday timeframes as well as cross-border adjustments in the balancing timeframe.

3.1. FLOWS PER BORDER

51. Figure 3-1 shows the evolution, between 2015 and 2022, of the net export flows per border, taken by subtracting the import flows from the export flows.[10] During the considered period, an alternating pattern between net export to and from the Netherlands and France has been witnessed: periods of high net import from France coincided with periods of (relatively) low net import (or net export) from the Netherlands. Globally however, Belgium was a net importer between 2015 and 2018 (see also Figure 3-3). This seasonal pattern persists even until 2022, even though Belgium has become, on average, a net exporter. The remarkable structural export to Great Britain between 2019 and 2022 decreased in 2022, showing a more balanced position (with more import in the summer).

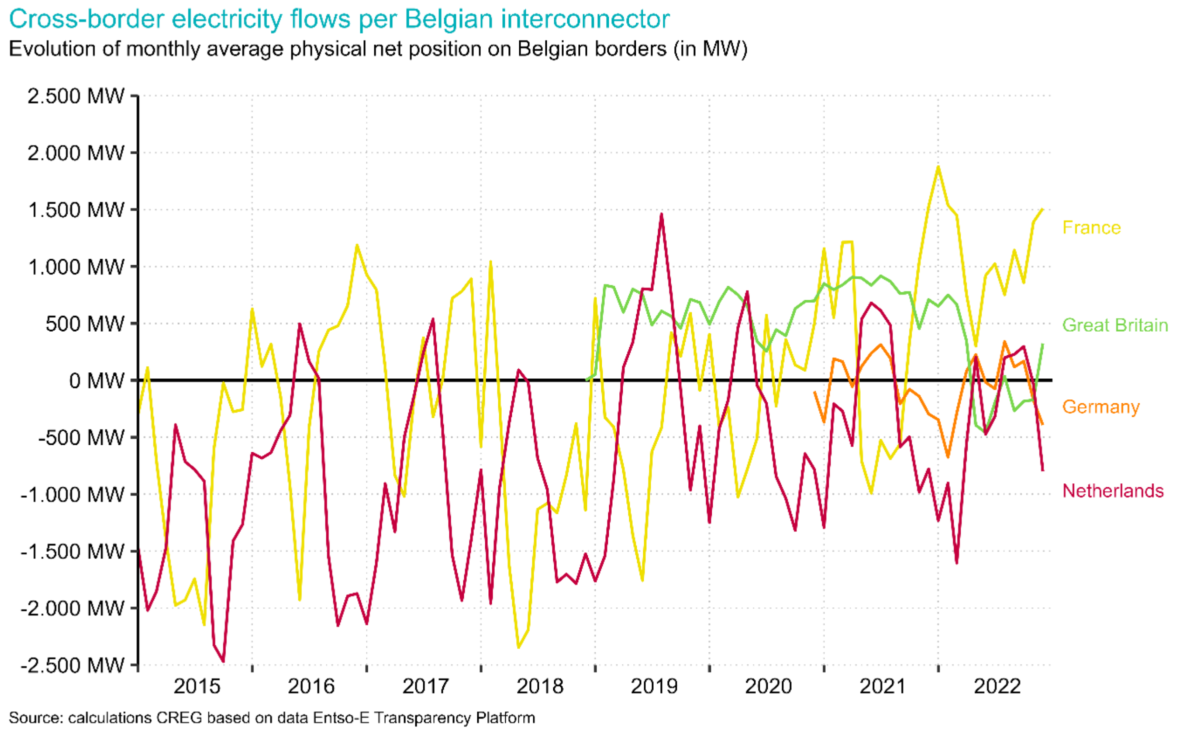


Figure 3-1 Cross-border electricity flows per Belgian interconnector

[9] Given the small size of, and the limited exchanges over, the interconnector with Luxembourg (220 kV line between Aubange and Belval), this chapter will focus on the four other neighbouring countries. Data reported on the Entso-E Transparency Platform allocates flows on this interconnector to Germany, as it forms one bidding zone with Luxembourg. This is also why Great Britain is considered: this is the bidding zone (while the United Kingdome is the country).

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

52. The total physical export of electricity from Belgium reached 19,2 TWh in 2022, representing a slight decrease compared to the record value in 2021 (20,0 TWh). The main share of these exports were directed towards France (10,7 TWh), followed by Great Britain (3,3 TWh). During the same year, 12,9 TWh of electricity were imported, mainly from the Netherlands (6,2 TWh) and Germany (3,3 TWh). This led to a positive export balance (net export was 6,3TWh, compared to 7,6 TWh in 2021): since 2019, Belgium is structurally and increasingly exporting electricity. This observation starkly contrasts the situation in the preceding years, when Belgium had to rely on structurally very high import volumes (with a record 20,7 TWh net import in 2015). Roughly speaking, in half a decade time, the net export position of Belgium shifted with more than a quarter of the country's total consumption (a shift of 27,0 TWh from 2015 to 2022).

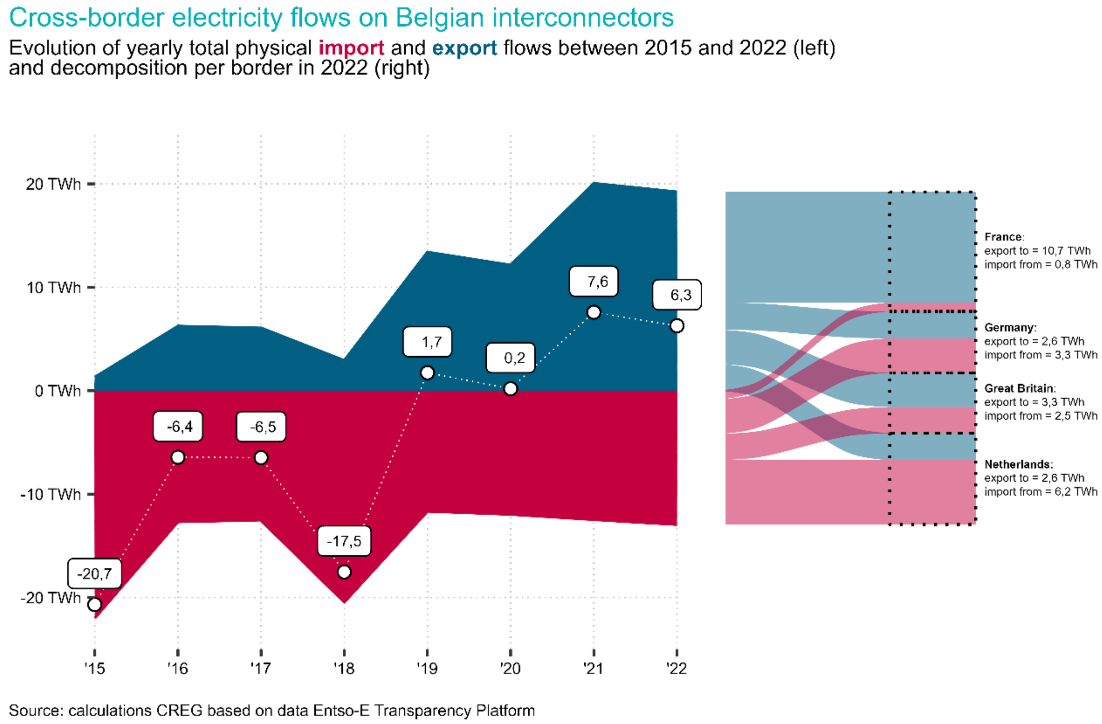


Figure 3-2 Cross-border electricity flows on Belgian interconnectors

3.2. TOTAL NET POSITION

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

- the entry into operation of the Nemo Link and ALEGrO interconnectors in respectively 2019 and 2020;
- the decrease of the electricity load (consumption) in Belgium, discussed in chapter 1; and
- the increase in electricity generation in Belgium since 2018, as shown in section 2. In particular, the high availability of Belgium's nuclear production units in 2021 and 2022 has had a positive import on its net export position.

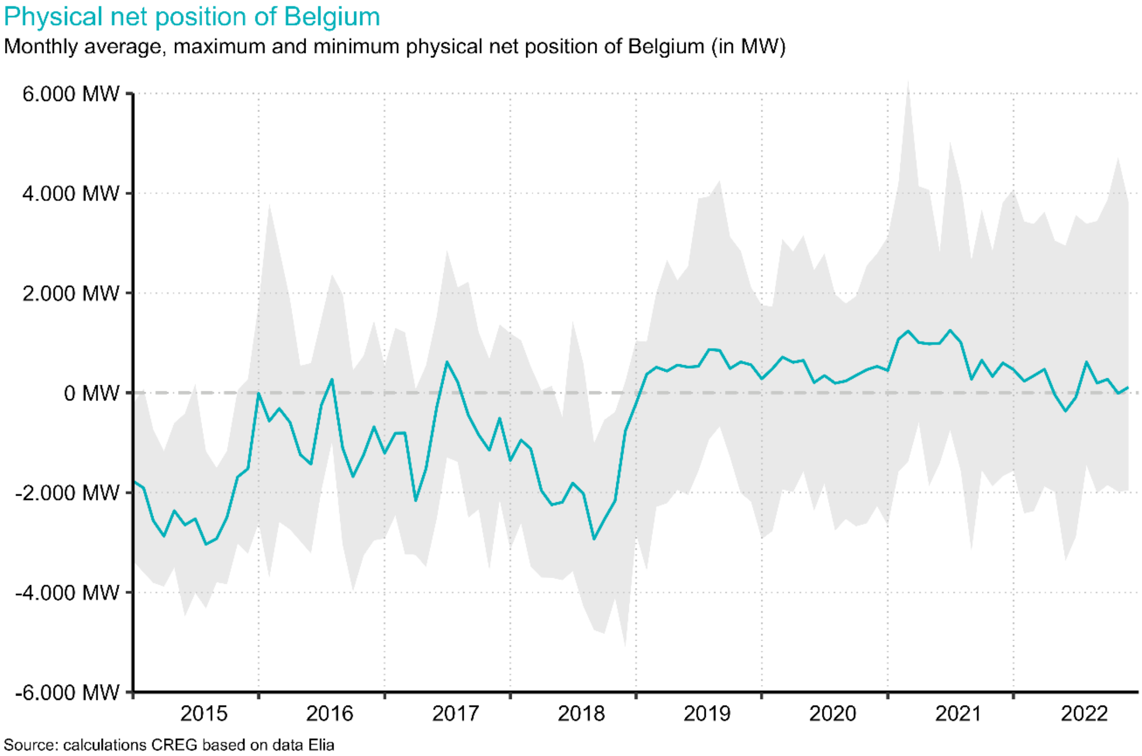


Figure 3-3 Physical net position of Belgium

(in TWh)	France	Netherlands	Germany	Great Britain	TOTAL
2015	-8,3	-12,4	0,0	0,0	**-20,7**
2016	0,5	-6,9	0,0	0,0	**-6,4**
2017	1,6	-8,1	0,0	0,0	**-6,4**
2018	-8,6	-9,0	0,0	0,0	**-17,6**
2019	-2,8	-0,9	0,0	5,4	**1,6**
2020	-0,8	-4,0	0,0	5,0	**0,2**
2021	2,6	-2,1	0,0	7,0	**7,6**
2022	9,8	-3,6	-0,7	0,8	**6,3**

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

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

3.3. PHYSICAL INTERCONNECTION CAPACITY

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

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

Source: calculations CREG based on data Elia

Table 3-2 Installed transmission capacity connecting Belgium to neighbouring countries

4. LONG-TERM MARKETS

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

56. In this chapter, different futures markets will be described. Some of these markets are purely national (for delivery in Belgium) while others are cross-zonal (for exchanging energy with coupled neighbouring zones, such as France, the Netherlands, Germany or Great Britain).

4.1. FUTURES MARKETS FOR DELIVERY IN BELGIUM

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

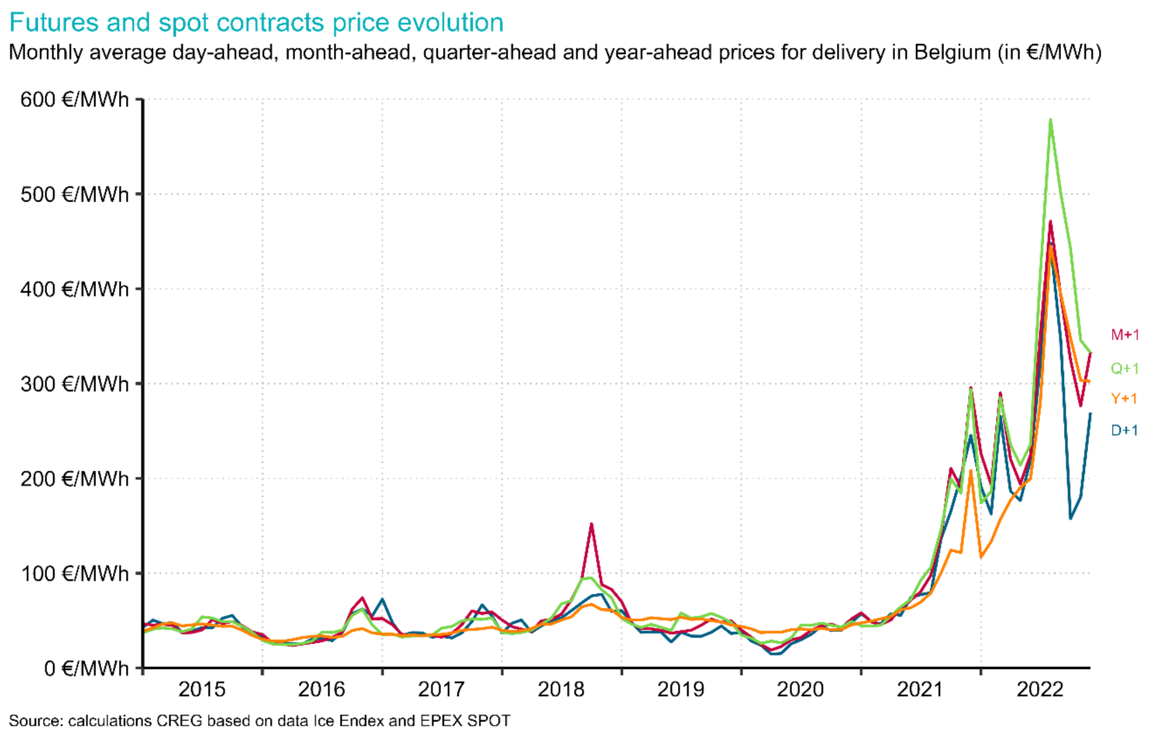


Figure 4-1 Futures and spot contracts price evolution

58. The evolution of the monthly average prices for different futures contracts (on one month-ahead, one quarter ahead and one year ahead) and the day-ahead spot contracts is shown in Figure 4-1.[11] When the price for a futures contract (for example, Y+1) is higher than the day-ahead price on contract data, it implies that, on average, market participants anticipate that prices will increase for the relevant delivery period (in this case, the entire subsequent year). As an example, the observed prices at the end of 2022 suggested that market participants anticipated that the observed decrease in day-ahead prices in the third quarter was temporary. Average prices for delivery in January 2023 reached 333,3 €/MWh, for delivery in the first quarter this was 332,5 €/MWh and for delivery in the entire year 2023 this was 302,5€/MWh, while the day-ahead price in December 2022 was, on average, only 269,3 €/MWh.

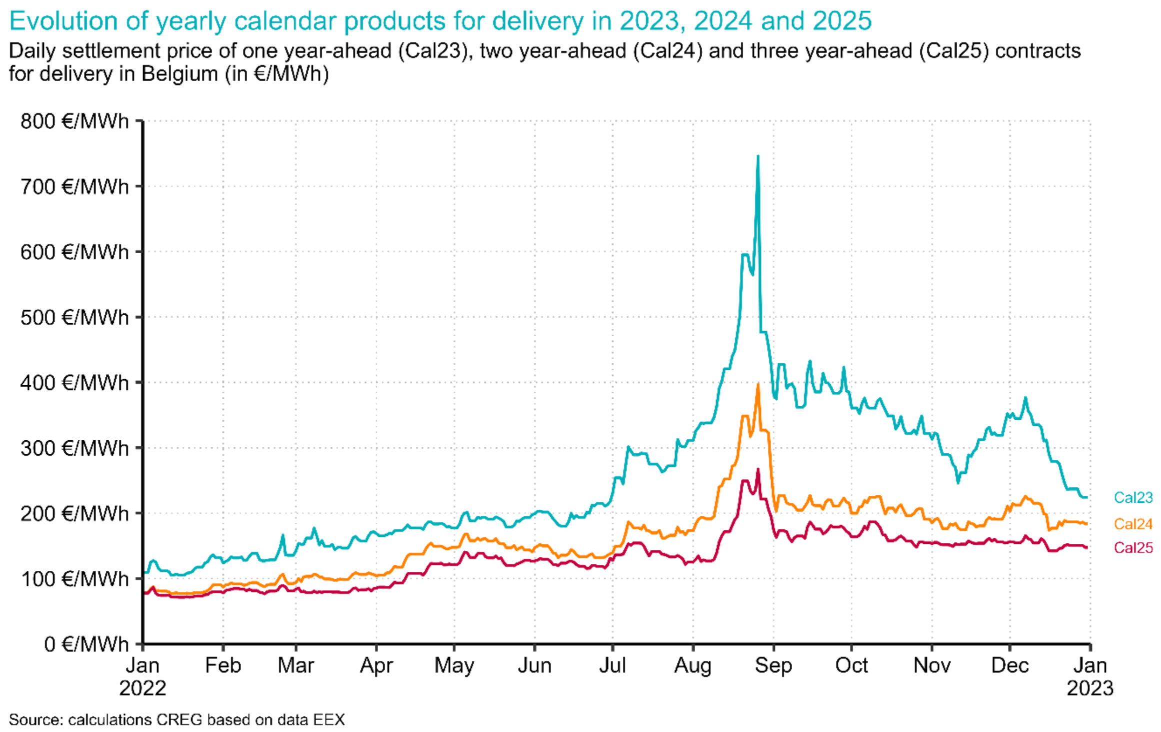


Figure 4-2 Evolution of yearly calendar products for delivery in 2023, 2024 and 2025

59. Figure 4-2 shows the evolution of three yearly contracts (Y+1, Y+2 and Y+3) throughout 2022. The first one, Y+1, shows the price for delivery of energy in 2023, the second, Y+2, for delivery in 2024 and the third, Y+3, for delivery in 2025 (these are the so-called “Cal23”, “Cal24” and “Cal25” products). The Cal24 and Cal25 products show a particularly close price evolution, while the Cal23 is a bit more volatile. All of these have, however, shown the same remarkable peak in August 2022, where record high prices for yearly futures contracts have been observed, up to almost 750€/MWh for the Cal23 product on 26 August 2022.

60. Even though the prices for futures and spot contracts, as listed on the contract data, show similar movements, it makes more sense to compare the prices at the same delivery period. This comparison shows the relative cost (or revenue, depending on the market participant) for buying (or selling) electricity via spot markets or futures markets. This is shown in Figure 4-3 below, where different available contracts are matched and compared on the delivery date.

[11] Monthly averages are computed as the arithmetic mean of the daily settlement prices of a specific month, irrespective of the delivery period.

61. From this figure, it can be clearly observed that, depending on the purchasing / selling strategy of a market participant (i.e. either primarily in the spot markets, or through futures contracts), the cost for buying or revenue from selling electricity may differ significantly.[12] In particular, for the delivery year 2022, purchasing electricity was much less expensive if done through (longer-term) futures contracts (such as Q+2, Q+3, Y+1, Y+2 or Y+3) than on the spot market, shown by the blue bars in the figure below. The more electricity has been sold in advance, i.e. through multi-year contracts, the more profitable for a buyer if compared against buying the same volumes in the day-ahead markets. This does not hold for shorter-term futures contracts (M+1, M+2, M+3 and Q+1): covering the need for electricity throughout 2022 with these contracts was typically more expensive than through day-ahead contracts. The inverse reasoning goes for sellers: these earned higher revenues from selling their electricity through M+1, M+2, M+3 or Q+1 contracts compared to the day-ahead revenues, but lower revenues from Q+2, Q+3, Y+1, Y+2 or Y+3 contracts.

62. The spreads between the day-ahead prices and the yearly futures contracts (Cal-22 throughout 2019, 2020 and 2021) are remarkable: buying electricity in 2021 for delivery in 2022 was 158 €/MWh less expensive than on the day-ahead timeframe. Doing the same in 2019 (with Y+3 contracts) cost 195,8 €/MWh less than with day-ahead contracts, while the Y+2 contracts throughout 2020 were 201,1 €/MWh less expensive, as shown in the bottom row of figures in the below figure.

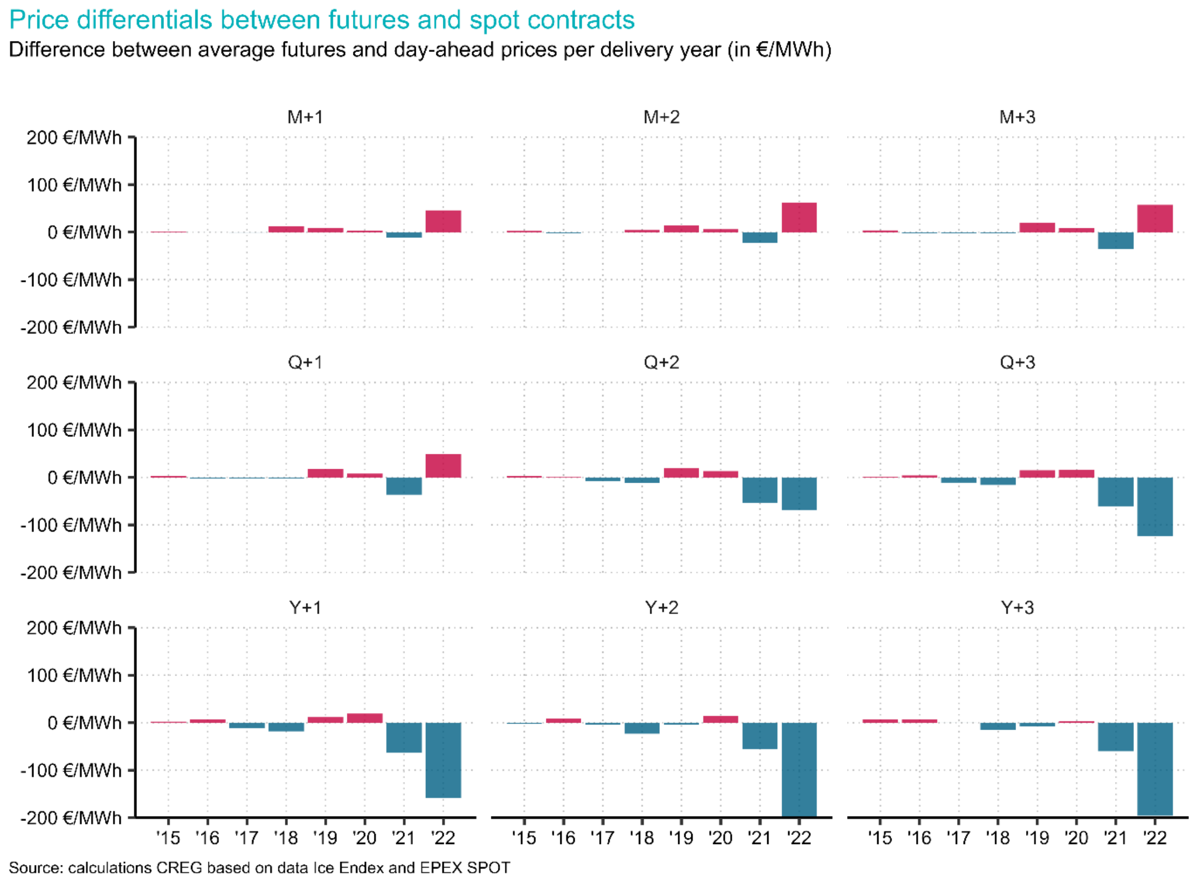


Figure 4-3 Price differentials between futures and spot contracts

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

63. Year-ahead prices, just as day-ahead prices, are on average quite closely aligned among different, coupled countries (even though they only reflect delivery in one specific country).[13] Since 2022, however, significant price differentials between local Y+1 contracts has been observed, contrary to the very close alignment in 2021 and the preceding years. Especially the French Y+1 contracts (367.6 €/MWh in 2022), but also the Austrian (313,1 €/MWh) and German (298,3 €/MWh) ones, have been significantly more expensive than Belgian (255,6 €/MWh) or Dutch (264,7 €/MWh) contracts. The evolution of monthly average Y+1 prices in Belgium and its neighbouring countries is shown in Figure 4-4.

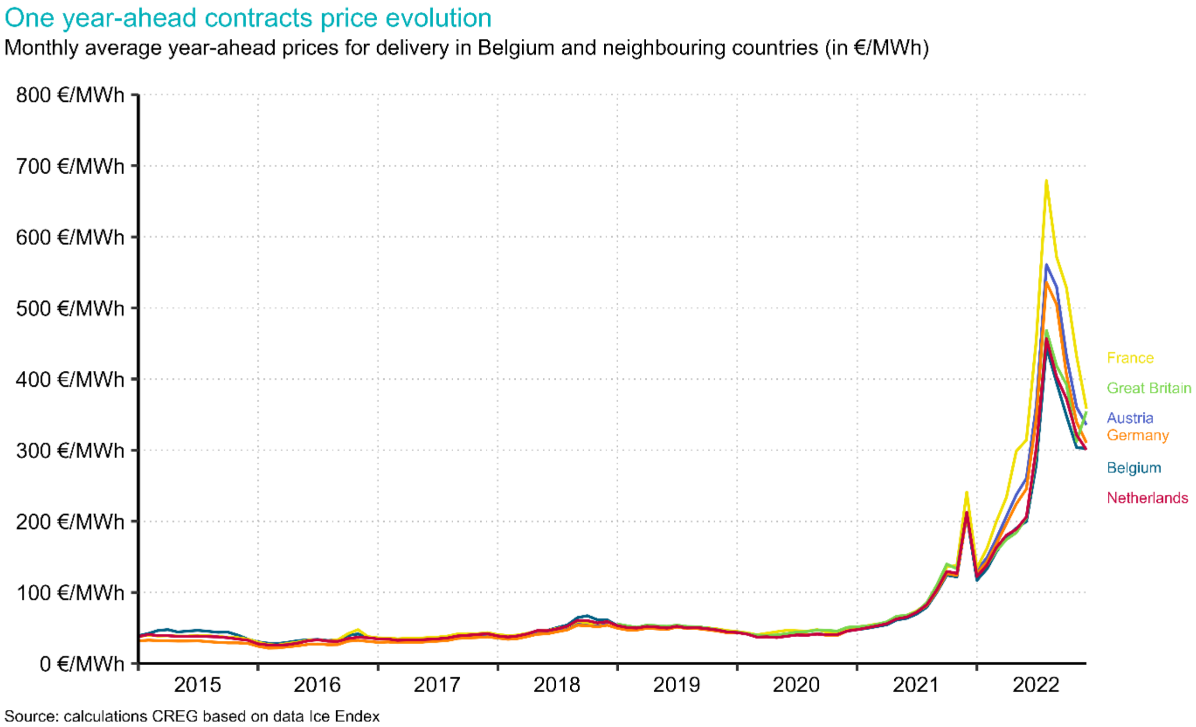


Figure 4-4 One year-ahead contracts price evolution

[13] Prices of these futures contracts reflect market participants anticipations of day-ahead prices, and these day-ahead prices are closely aligned in well-coupled regions such as the CWE or Core.

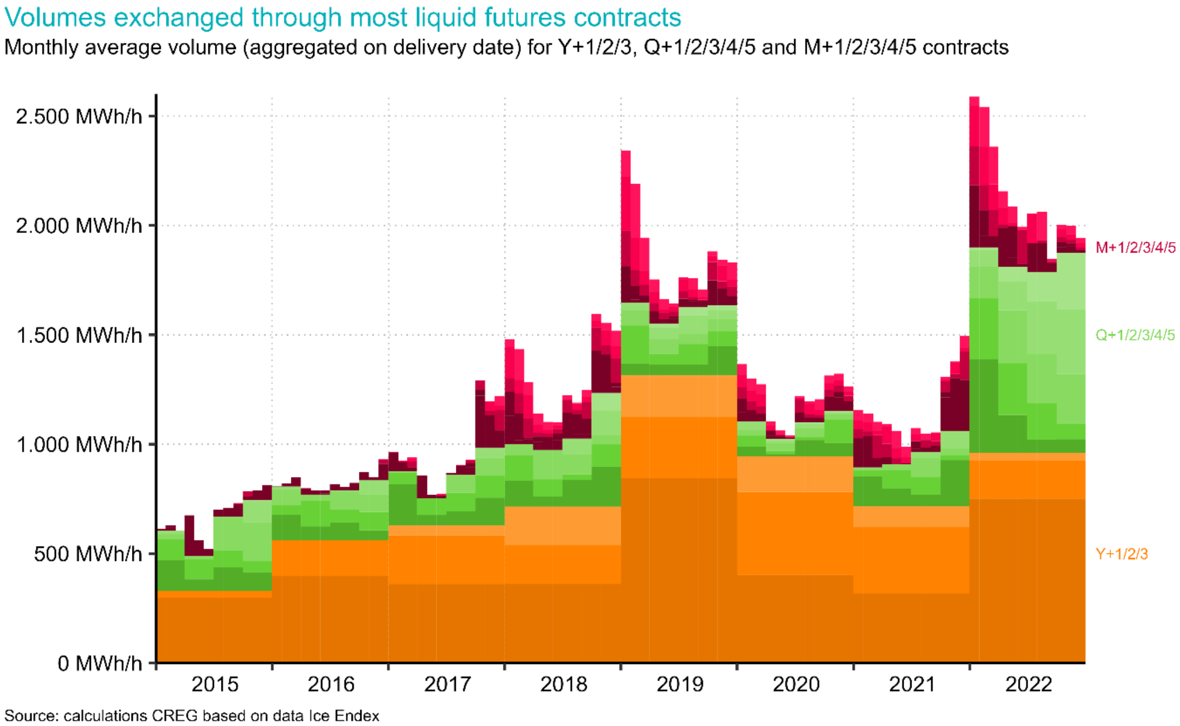


Figure 4-5 Volumes exchanged through most liquid futures contracts

64. Figure 4-5, finally, summarizes the volumes of electricity bought or sold, summarized as averages per month (grouped on delivery date, not on contract date). In 2022, between 1.800 and 2.600 MWh/h was delivered, on average, through the most liquid yearly, quarterly and monthly products.[14] This is a significant increase compared to 2021, when these volumes varied only between 1.000 and 1.500 MWh/h. The increase results mostly from the quarterly contracts becoming more liquid, reaching levels that before were only seen in the most liquid yearly contracts. The highest ever monthly average volumes was observed in January, reaching 2.588 MWh/h.

4.2. LONG-TERM CROSS-ZONAL MARKETS

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

[14] The figures shows volumes for M+1, M+2, M+3, M+4, M+5, Q+1, Q+2, Q+3, Q+4, Q+5, Y+1, Y+2 and Y+3 contracts, even though other products exist.

4.2.1. Yearly timeframe

66. This subsection shows the result for the explicit auctions for yearly cross-zonal capacity on the borders between Belgium on the one hand, and France, the Netherlands, Great-Britain and Germany on the other hand. These auctions are usually organized by JAO in the month of November preceding the year of delivery[15] and the results are subsequently published on JAO's web page.[16]

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

67. The allocated volumes for yearly cross-zonal capacity on the border with France have historically been relatively stable in the import direction: in 2022, 1.450 MW was available for cross-zonal trade. These values are significantly lower in the export direction, where only 250 MW was sold through the explicit auctions. The allocated volumes on the French border (in both directions) are shown in the top panel of Figure 4-6.

68. The bottom panel shows the resulting marginal price. Market participants who submitted bids at prices at least equal to the marginal price obtained cross-zonal capacity as a result. This marginal clearing price is determined at the intersection between the inelastic supply curve (i.e. the TSOs' offered capacity) and the demand (i.e. the bids introduced by the market participants, ordered from high to low price). Year-to-year fluctuations are much more pronounced in the prices than in the volumes: these prices are the result of the market participants' expectations of the day-ahead price spread (and its volatility) in the relevant market time unit. For the 2023 auction, prices for annual cross-zonal capacity on the Belgian – French border rose spectacularly in the export direction, to 98 €/MWh (against 29,2 €/MWh for the 2022 timeframe), while the price for import capacity remained stable (4,4 €/MWh for the 2023 capacity against 1,8 €/MWh for 2022).[17]

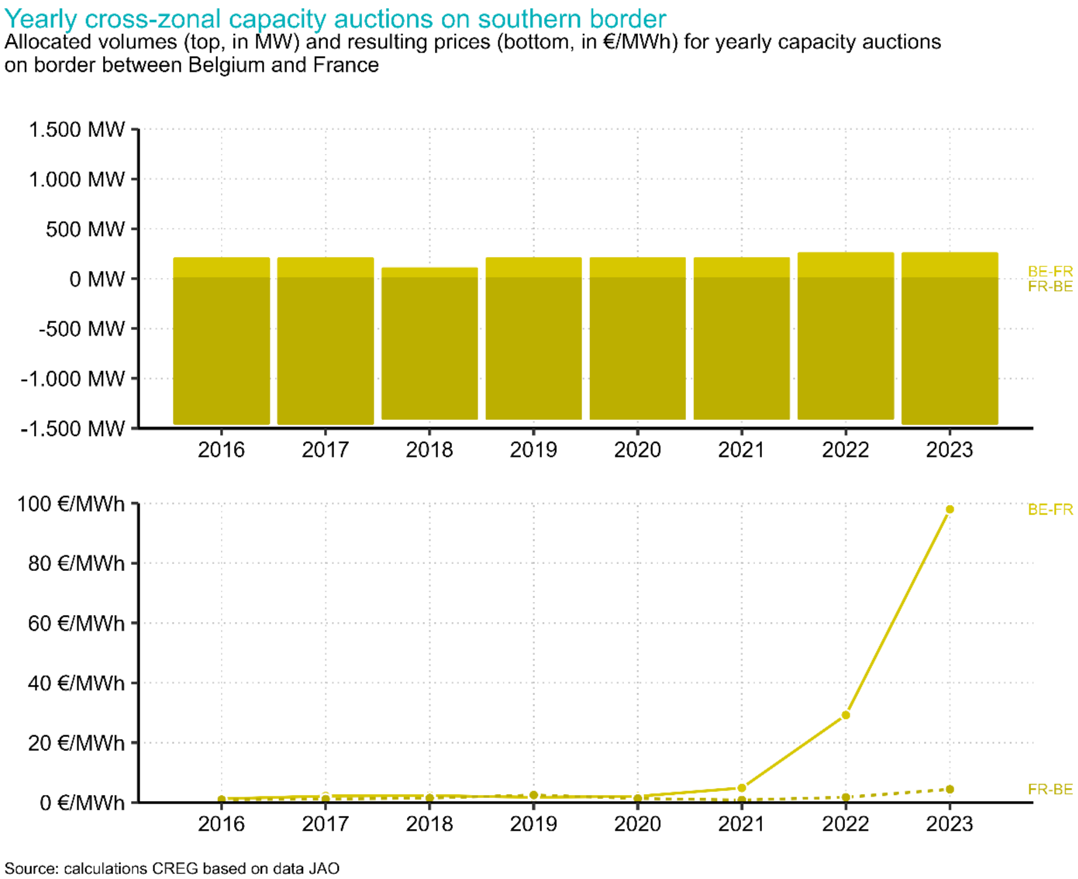


Figure 4-6 Yearly cross-zonal capacity auctions on southern border

[17] Volumes and prices for 2023 cross-zonal capacity are already included, as these auctions took place in November 2022.

69. On the northern border with the Netherlands, cross-zonal capacities are sold in a more even manner between the import and the export directions. Allocated capacities reached 473 MW in both directions. These values have been nearly identical in the last years.

70. This does not necessarily imply stable prices: between 2016 and 2022, prices fluctuated between 1 and 5 €/MWh. The cost for yearly cross-zonal capacity for delivery in 2023 increased to 13,2 €/MWh (export) and 10,3 €/MWh (import).

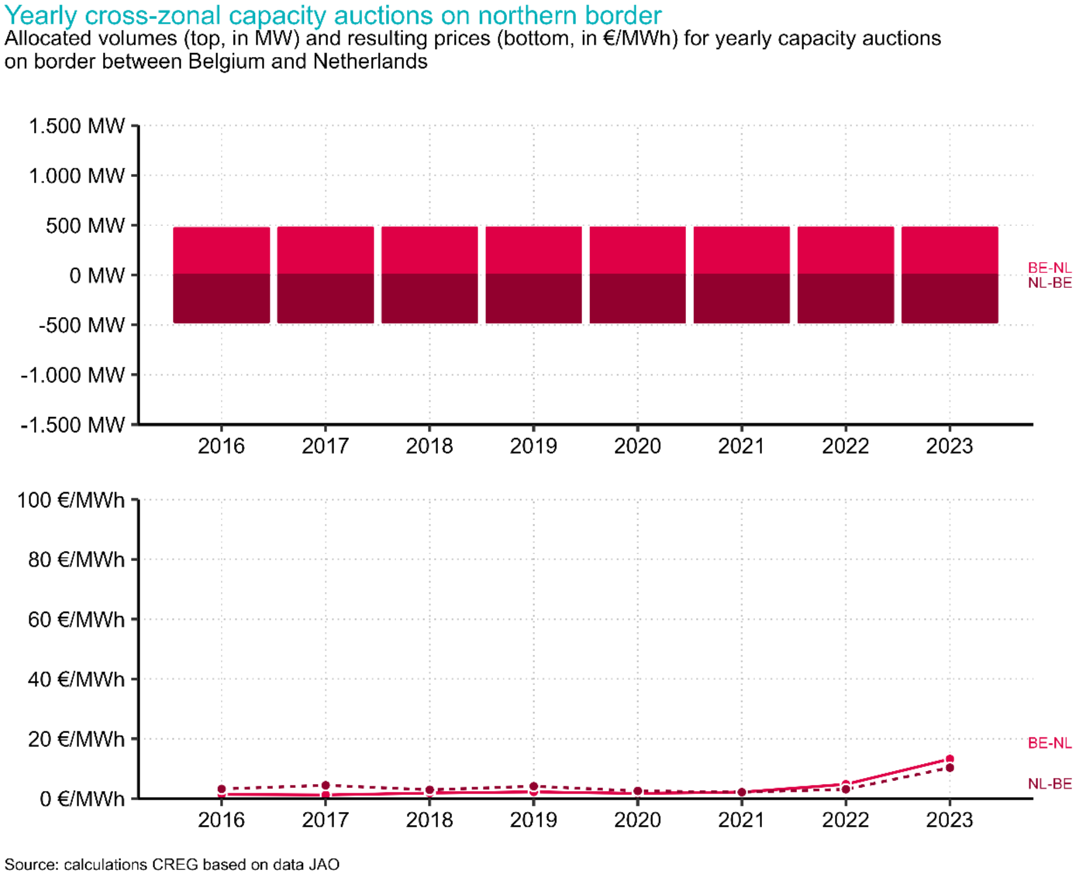


Figure 4-7 Yearly cross-zonal capacity auctions on northern border

71. On the border with the bidding zone Great-Britain (part of the United Kingdom), data for the yearly allocations is only available since the end of 2019 (the auction held was for 2020 yearly capacity), as the Nemo Link interconnector only became operational in early 2019. The allocated capacities reached 350 MW (export) and 425 MW (import) in 2023, showing a strong decrease since 2022 (675 MW in both directions).

Fluctuating volumes of allocated capacities (compared to the total available capacities) in different long-term timeframes reflect commercial strategies of Nemo Link, agreed with the relevant TSOs (Elia and National Grid). The auctions are held at different times throughout the year preceding the delivery: the volumes shown in Figure 4-8 are the total of all auctions for a specific yearly timeframe.

These auctions resulted, for 2023, in marginal prices which were somewhat lower than for 2022 in the export direction: 13,4 €/MWh compared 22,2 €/MWh. For the import direction, prices increased from 0,3 €/MWh in 2022 to 1,5 €/MWh in 2023.

This matches the observed patterns in the day-ahead timeframe (see also chapter 5): Nemo Link is structurally used in the export direction, to transport electricity from Belgium to Great-Britain. This explains the higher value which market participants attach to capacity in the export directions, reflected in their bids for capacity in the explicit auctions. In turn, the desire to export electricity results from the observed price differences in the day-ahead timeframe.[18]

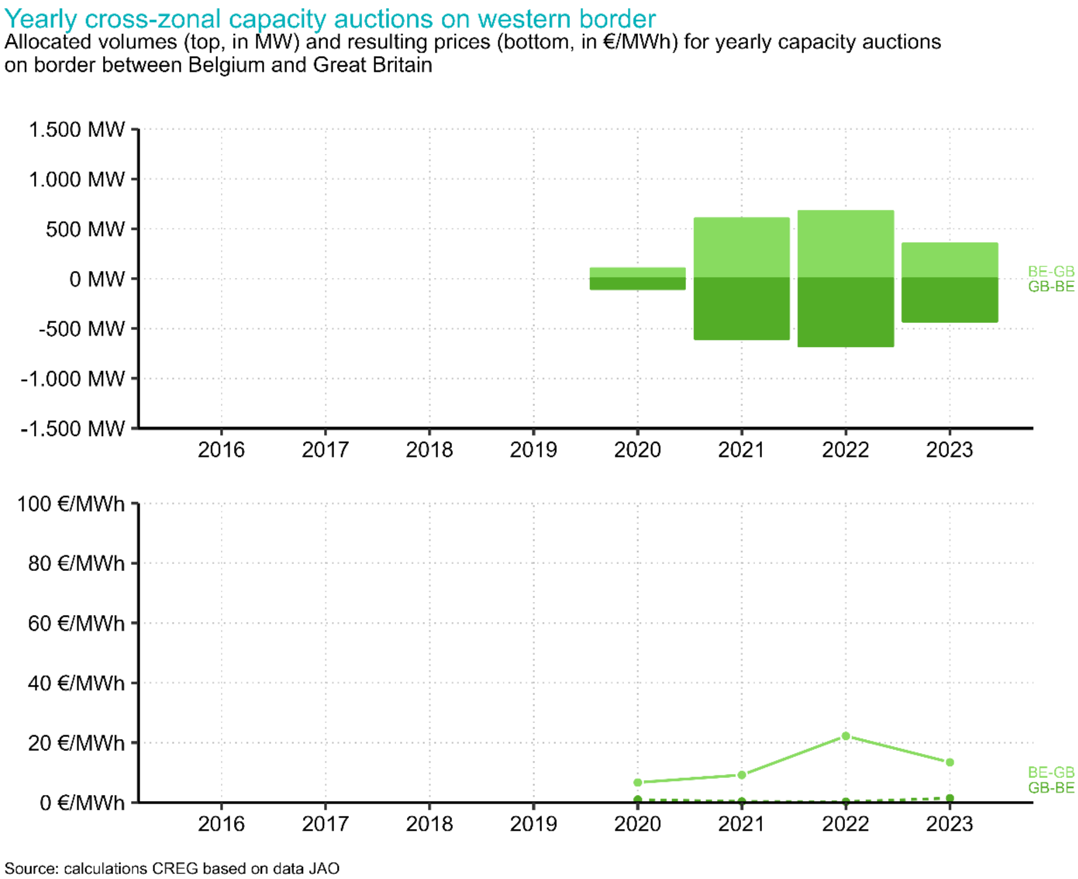


Figure 4-8 Yearly cross-zonal capacity auctions on western border

[18] This observation is particularly relevant for the first half of 2022: as we'll demonstrate, the direction of commercial trade has shifted throughout the year, towards more import flows for Belgium in the second half of 2022. This also explains why the value of export capacity decreased from 2022 to 2023.

72. Finally, the results for the yearly cross-zonal capacity auctions on the ALEGrO interconnector for the 2022 and 2023 timeframe is shown in Figure 4-9. The first annual auctions were organized in November 2021, as the interconnector entered into operations at the end of 2020 (too late for organizing 2021 yearly auctions). In the export direction, 260 MW was sold at a marginal price of 27,4 €/MWh (increasing from 5,2 €/MWh the preceding year), while in the import direction, also 260 MW was sold yet at a lower price (12,3 €/MWh, against 4,3 €/MWh before).

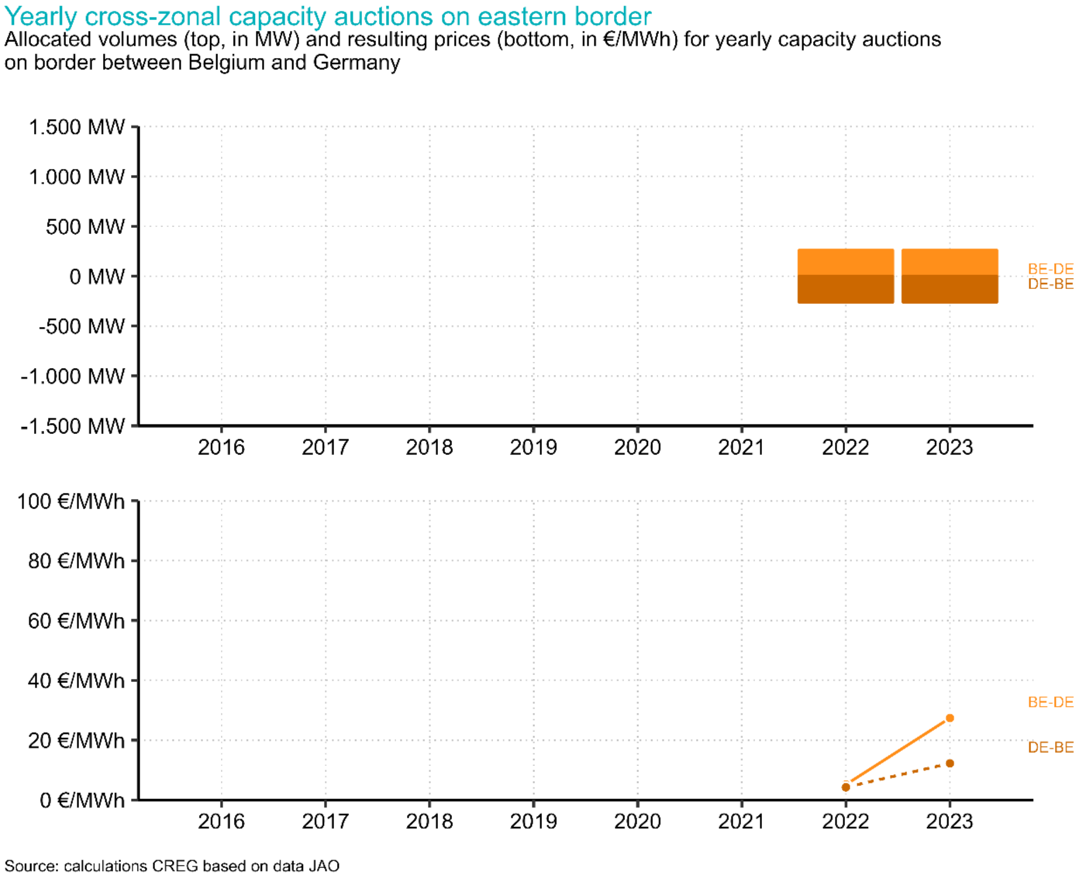


Figure 4-9 Yearly cross-zonal capacity auctions on eastern border

4.2.2. Monthly timeframe

73. This subsection summarizes the explicit auctions for monthly cross-zonal capacity on Belgium's borders. As for the yearly auctions, these are organized by and results are organized on JAO, generally a couple of days before the start of the delivery month. The following figures show the results of the capacity auctions on the borders with France, the Netherlands, Great Britain and Germany.

74. The volumes of monthly cross-zonal capacity auctions in both the export and import direction to and from France have, in 2022, varied between 200 and 600 MW. While prices did not exceed 5 €/MWh (in either direction) between 2019 and mid-2021, they started rising in the export direction from October 2021 onwards, reaching all-time high values of 149,8 €/MWh in November 2022. This price reflects the market conditions, with very high price differences and volatility of the price spreads between Belgium and France in the day-ahead timeframe. As this value does not exclusively reflect the positive price difference between the average day-ahead prices of both zones, it must include a significant risk premium, which is calculated by market participants in order to reflect the volatility of the price spreads between both countries.

Figure 4-10 shows the monthly total allocated volumes (top panel, in MW) and the resulting marginal prices (bottom panel, in €/MWh).

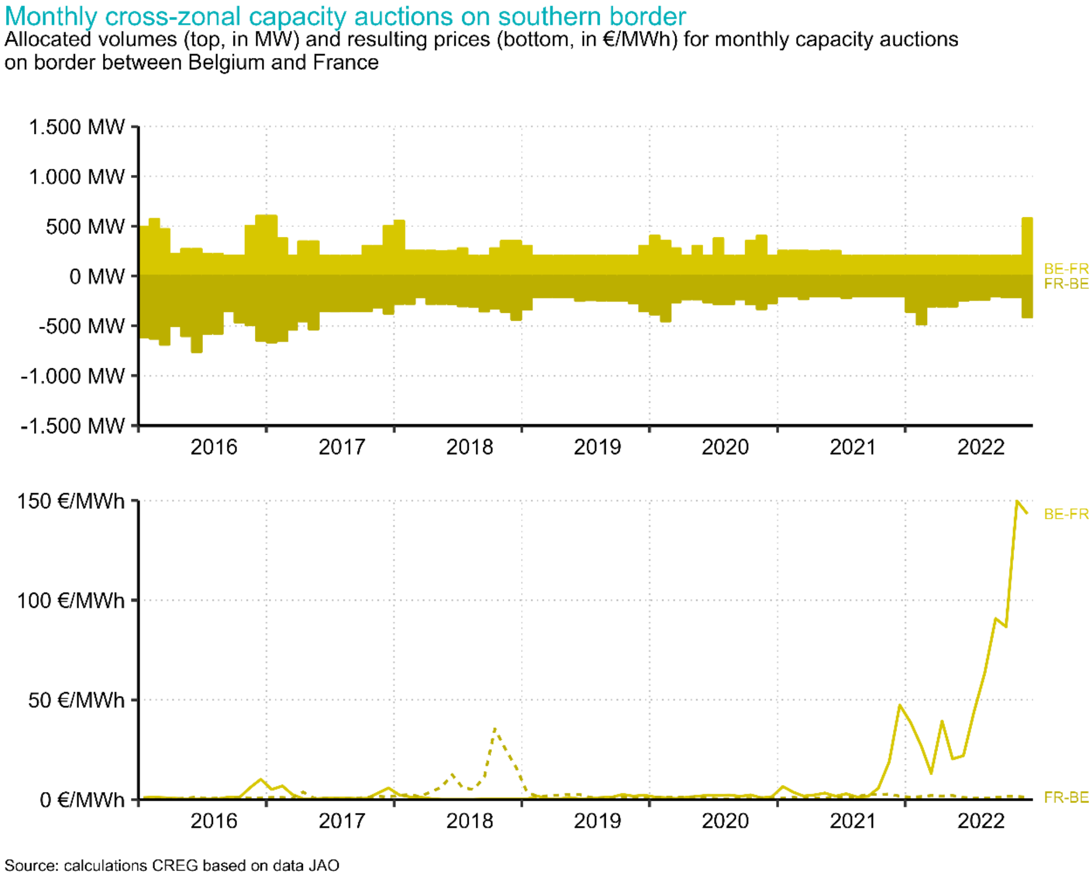


Figure 4-10 Monthly cross-zonal capacity auctions on southern border

75. Figure 4-11 shows, for the northern border with the Netherlands, the results of the monthly cross-zonal capacity auctions. The allocated volumes usually ranged, in 2022, between 100 and 200 MW in either direction. The resulting capacity prices are somewhat above the 2019 – 2020 averages: these started to increase in the second half of 2021 (as shown for France as well in the previous subsection).

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

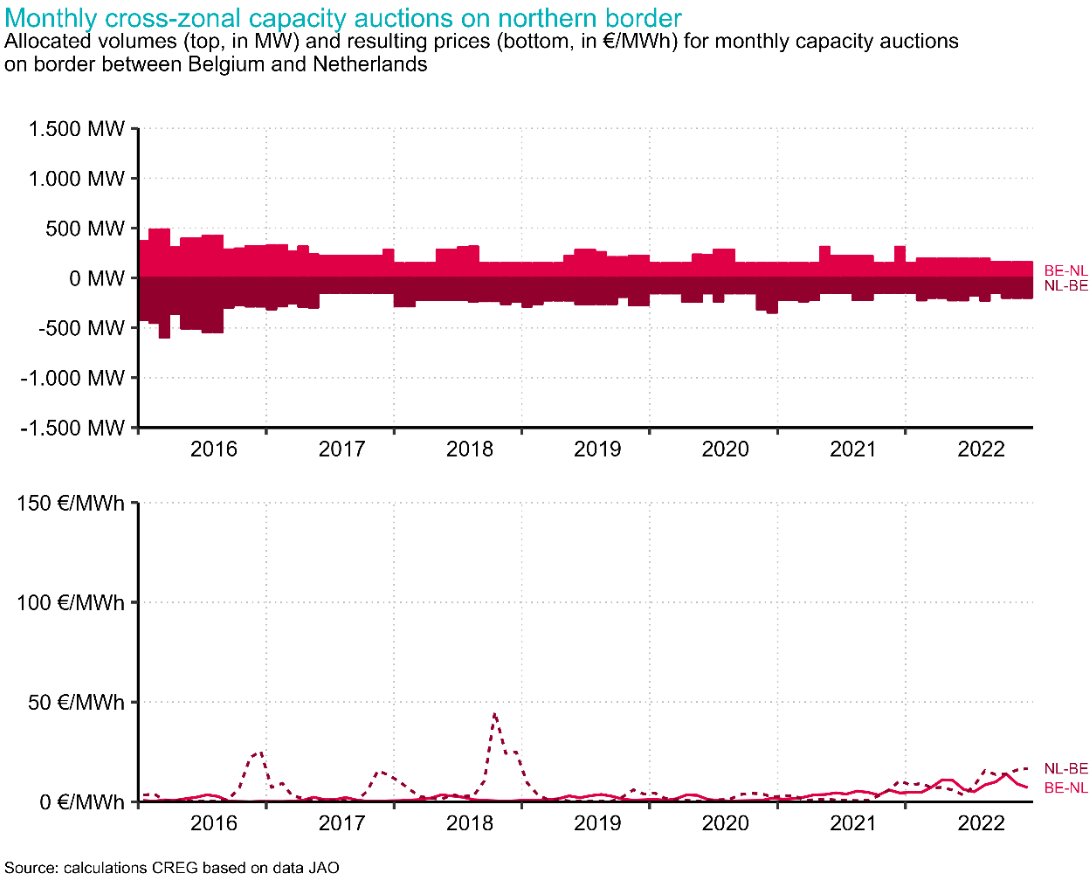


Figure 4-11 Monthly cross-zonal capacity auctions on northern border

76. On the western border with Great Britain, allocated volumes in 2022 are less stable than on other borders. In the summer months (June – August), higher import capacities are sold (270 – 340 MW, compared to only 75 – 80 MW in the export direction) than throughout the rest of the year.

Two significant peaks in the price of monthly export capacity have been observed: in January (106,5 €/MWh) and November (151,0 €/MWh), while in the import direction prices did not exceed 28 €/MWh (in August).

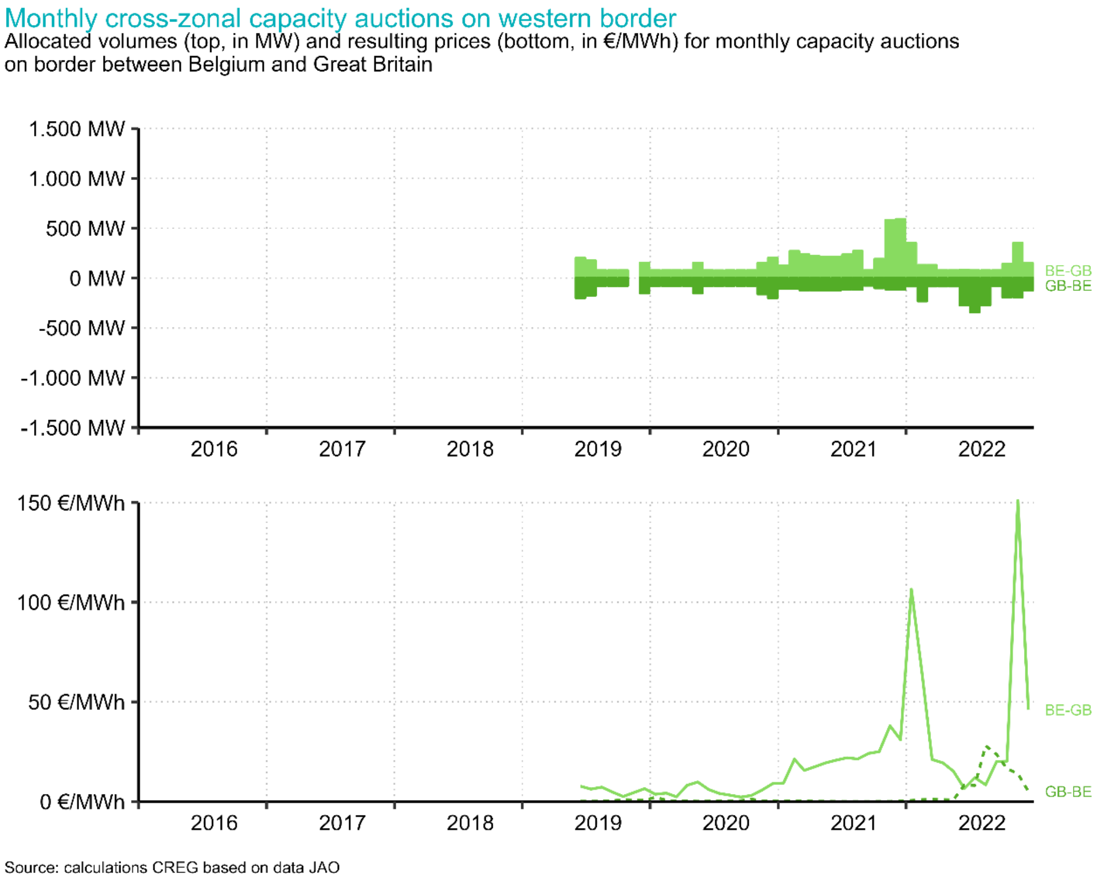


Figure 4-12 Monthly cross-zonal capacity auctions on western border

77. Finally, between 140 and 560 MW of monthly cross-zonal capacity were auctioned in 2022 on the ALEGrO interconnector. Here, the price increases in the day-ahead timeframe are reflected in the increasing value of the cross-zonal capacities in the import direction (from the end of 2021 onwards) and later (from mid-2022) also in the export direction. Prices reached their highest point in December 2022, equally 24,2 €/MWh for import capacities.

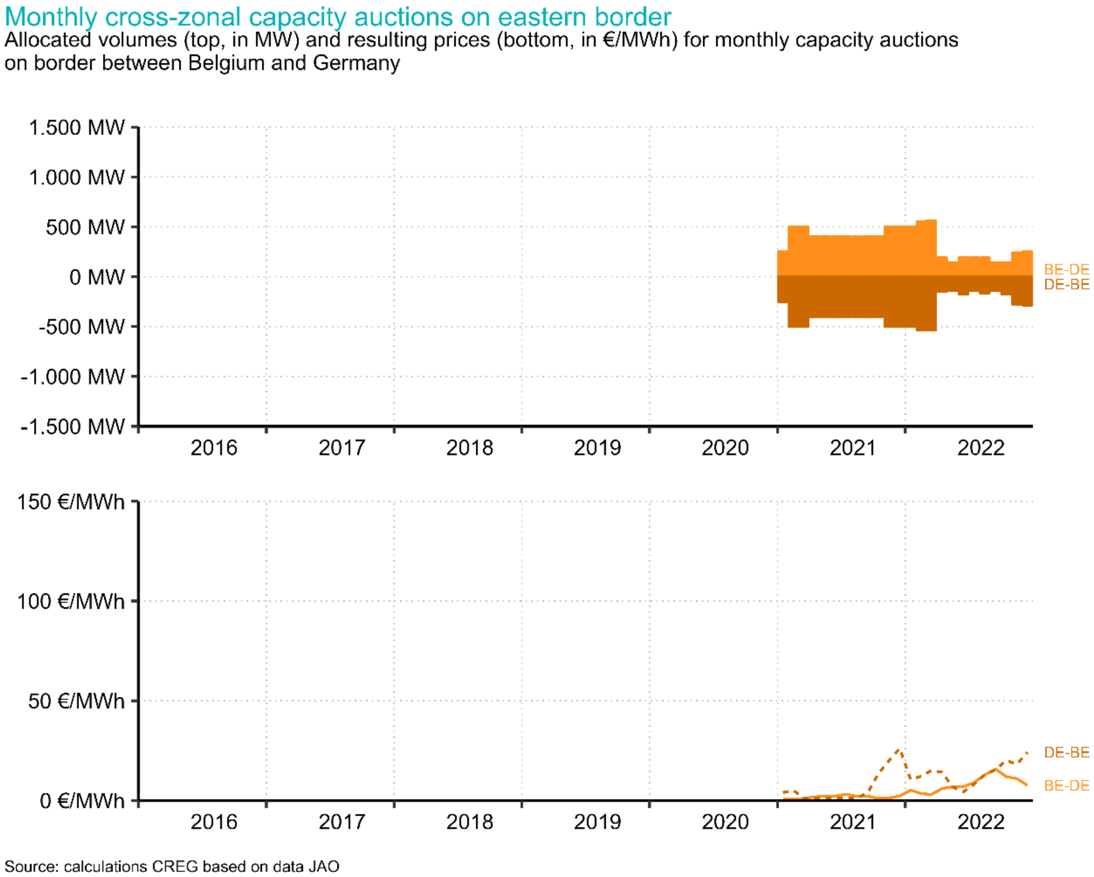


Figure 4-13 Monthly cross-zonal capacity auctions on eastern border

4.2.3. Other timeframes

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

79. There were no quarterly auctions in 2022 (the auctions for the first quarter were cancelled and the subsequent ones were not organized). This resulted from a decision from Nemo Link to allocate more capacity to the annual timeframes.

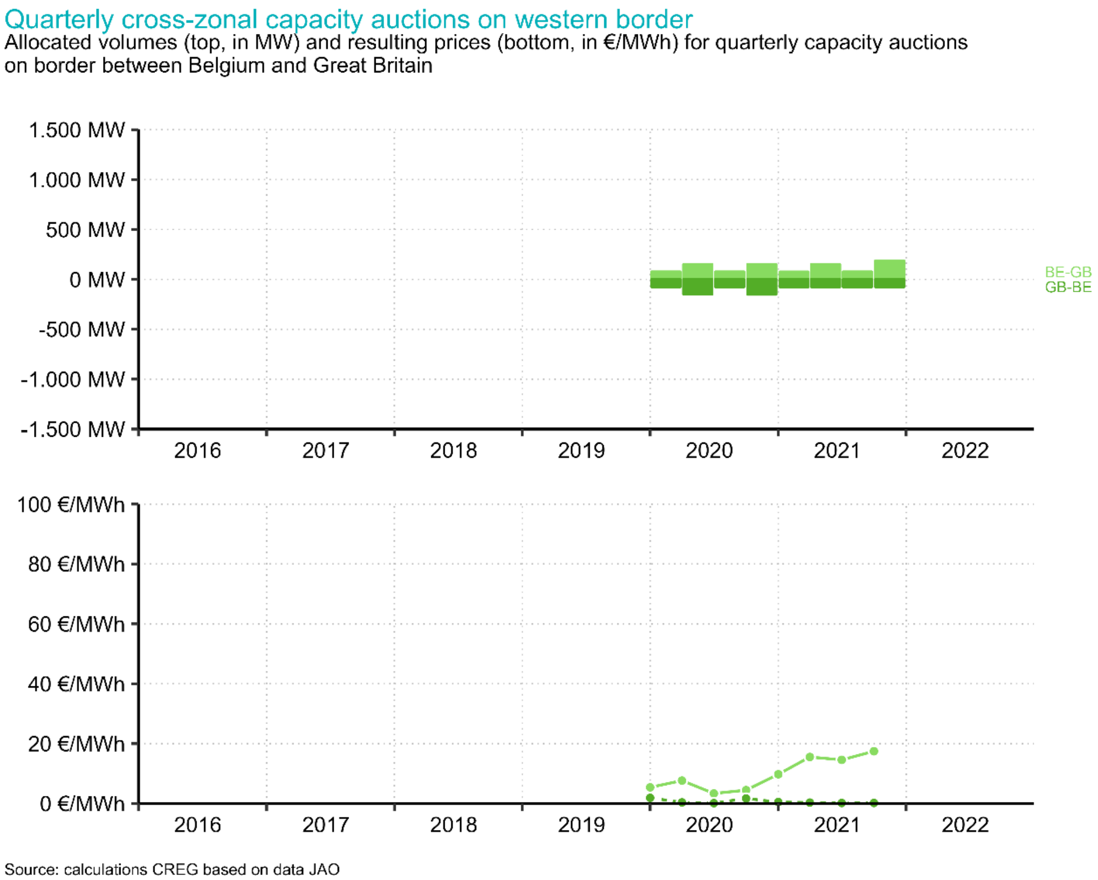


Figure 4-14 Quarterly cross-zonal capacity auctions on western border

4.2.4. Price of long-term transmission rights and day-ahead spreads

80. The difference between the auction price for long-term transmission rights and the day-ahead price spread gives an insight into the revenue adequacy of long-term congestion income for TSOs. Figure 4-15 shows, for each of the 110 auctions organized by Elia for delivery in 2022 (either yearly or monthly, on any of the 8 combinations of borders and directions), the difference between the price of the long-term transmission right and the day-ahead spread for the same delivery period. The auctions are sorted on decreasing delta between long-term auction price and day-ahead price spread, while the width of each bar corresponds to the allocated volume during that specific auction.

81. This figure shows that the largest income was generated from an auction on the BE – GB border (export), where market participants paid 151,0 €/MWh for long-term transmission rights, yet the price spread was -18,6 €/MWh in the day-ahead timeframe (Belgium being more expensive than Great Britain). Hence, a net difference of 169,6 €/MWh for that monthly auction (delivery in November 2022) was generated for the TSOs. The largest allocated volume (shown by the bar with the biggest width) is the yearly 1.400 MW (or 12.264 GWh) allocated on the FR-BE (import) border, where TSOs generated a net revenue of 33,1 €/MWh.

82. In total, 75,0% of the allocated volumes across all auctions in 2022 generated a net income (i.e. the bars with positive values), while 25,0% generated net losses (bars with negative values). No clear trend can be observed as to which borders typically generate net income, while others generate net losses.

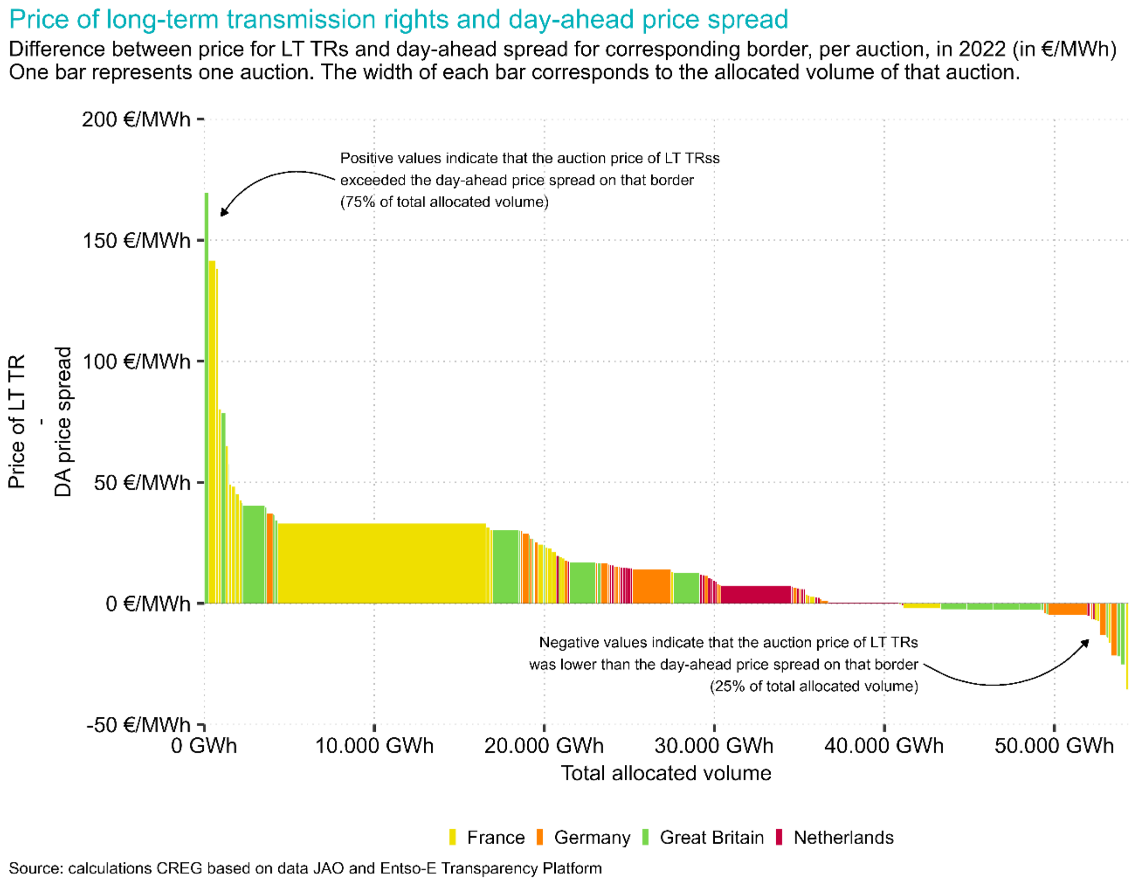


Figure 4-15 Price of long-term transmission rights and day-ahead spreads

4.2.5. Requested cross-zonal capacities

83. Figure 4-16 shows, for each border and direction, the difference between the average allocated and requested capacities from yearly, quarterly and monthly auctions, for delivery in 2021. Generally, market participants desire to acquire much more capacity than the volumes offered by Elia. Depending on the considered border, direction and timeframe, the requested capacities are about 10 to 15 times higher than what is made available.[19]

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

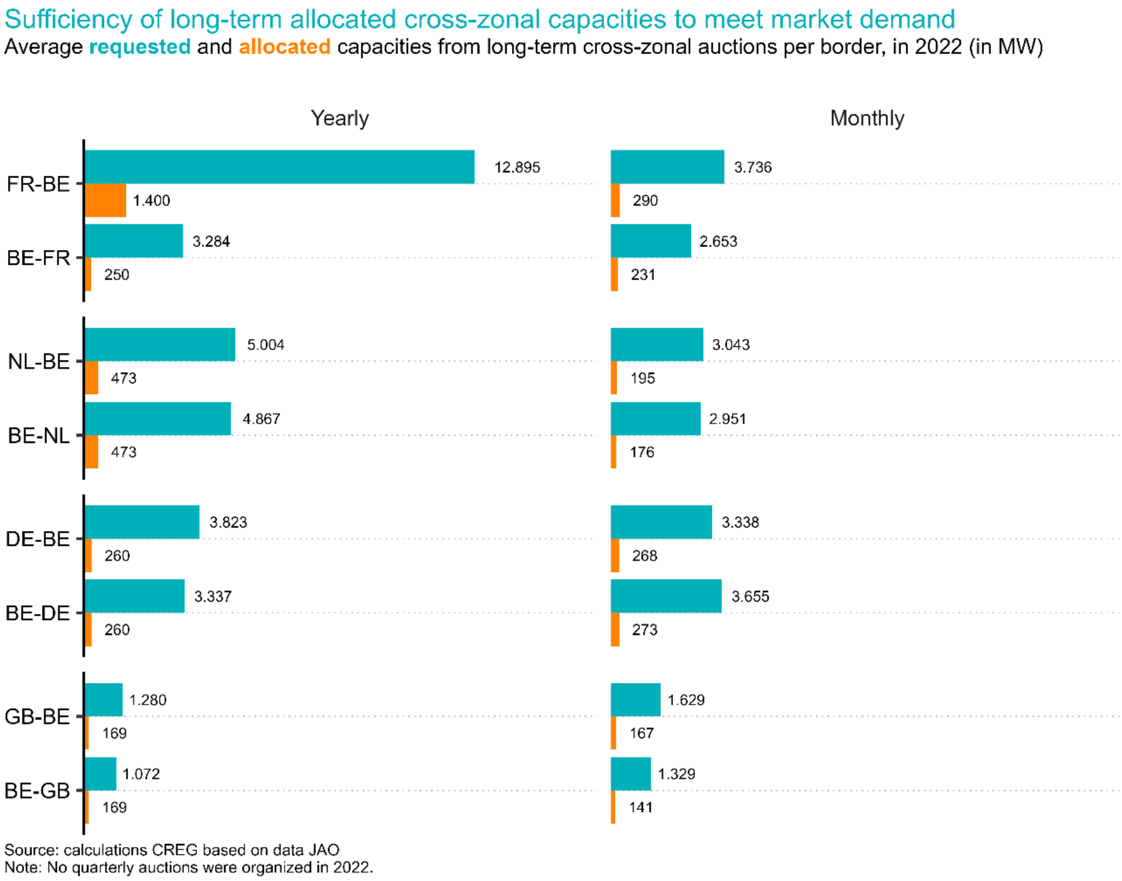


Figure 4-16 Sufficiency of long-term allocated cross-zonal capacities to meet market demand

[19] It is important to highlight that several auctions for the same timeframes are organized on the GB-BE / BE-GB borders. The values in **Figure 4-15** represent averages, not total capacities. For example, the average allocated capacity (over the different auctions) on BE-GB in the yearly timeframe was 169 MW (despite the total being 675 MW, see also **Figure 4-8**). On other borders, all capacities for the same timeframe are typically sold in one auction.

4.2.6. PTR nomination rates

85. Long-term cross-zonal capacities (for any of the relevant timeframes) are usually sold as transmission rights. Basically, two types exist in Belgium. On the borders with the Netherlands, France and Germany, "Financial Transmission Rights – Options" ("FTR-Options") are sold. The holder of these rights are remunerated for their entire capacity in case of a positive price spread between the two relevant bidding zones. Hence, there is no need for these FTR-Option holders to nominate their energy exchanges, as they are fully hedged against the price spread. On the border with Great Britain, however, "Physical Transmission Rights with Use-It-Or-Sell-It principle" (PTR-UIOSI) are used to allocate capacity. The holders of these rights have the choice of either to nominate their transmission rights before the long-term nomination closing gate (typically shortly before the start of the day-ahead market) or decide to return their rights to the Explicit Day-Ahead auction and get remunerated the clearing price.[20]

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

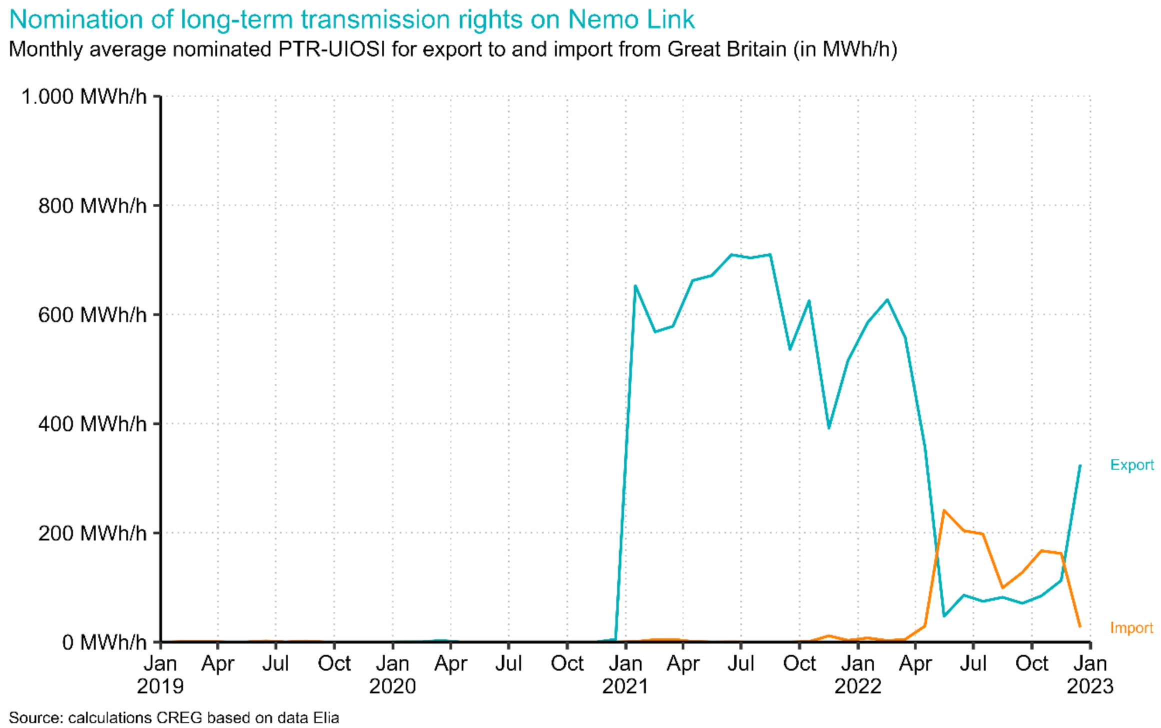


Figure 4-17 Nomination of long-term transmission rights on Nemo Link

[20] Note: this PTR-UIOSI principle was also in place on the other Belgian borders until 2015.

87. This is reflected in the evolution of the nomination rate in Figure 4-17. Before 2021, long-term rights were never nominated. Since 1 January 2021 (i.e. the effective Brexit date), the nominations of long-term export rights increased significantly, reaching about 600 MWh/h (or about 60% of the total capacity) on average in most months. This decreased – at least in the export direction – significantly in 2022: reflecting the changing relative position of Belgium and Great Britain, higher volumes were nominated in the import direction from April onwards.

5. DAY-AHEAD MARKETS

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

89. In July 2019, the Multi-NEMO Arrangements (MNA) were launched, allowing competition between the Nominated Electricity Market Operators (NEMOs). Market participants in Belgium have the choice to participate to the SDAC through one of the two designated NEMOs in Belgium: EPEX SPOT and Nord Pool.

90. In the day-ahead timeframe, cross-zonal capacities are calculated and allocated in different ways, depending on the considered borders and the point in time (see also Figure 5-1):

- Through the Central-West Europe Flow-Based Market Coupling (CWE FBMC), where capacities are calculated and allocated in an explicit manner (as part of the SDAC) between Belgium, France, the Netherlands, Germany/Luxembourg and Austria. This coupling mechanism was replaced by the Core Flow-Based Market Coupling (Core FBMC) Project, which involved an extension to Eastern European bidding zones: Croatia, Czech Republic, Hungary, Poland, Romania, Slovakia and Slovenia. The go-live of this project took place on 8 June 2023 (for delivery the subsequent date). A dedicated subsection regarding the impact of this shift will be included at the end of this chapter, in the section on capacity calculation (section 5.4).
- Through an explicit mechanism, whereby capacities on the Nemo Link interconnector are calculated via a (coordinated) Net Transfer Capacity approach. The functioning of this mechanism is explained in subsection 5.1.3.

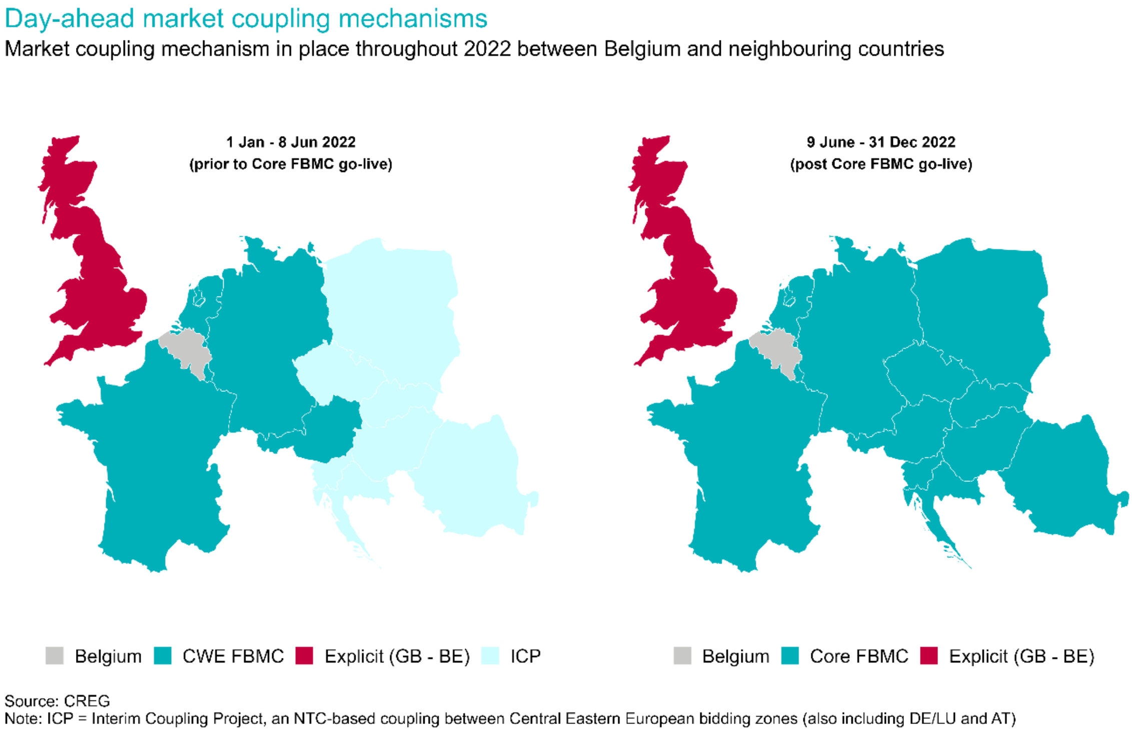


Figure 5-1 Day-ahead market coupling mechanisms

5.1. EXCHANGED VOLUMES

5.1.1. Belgian order books

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

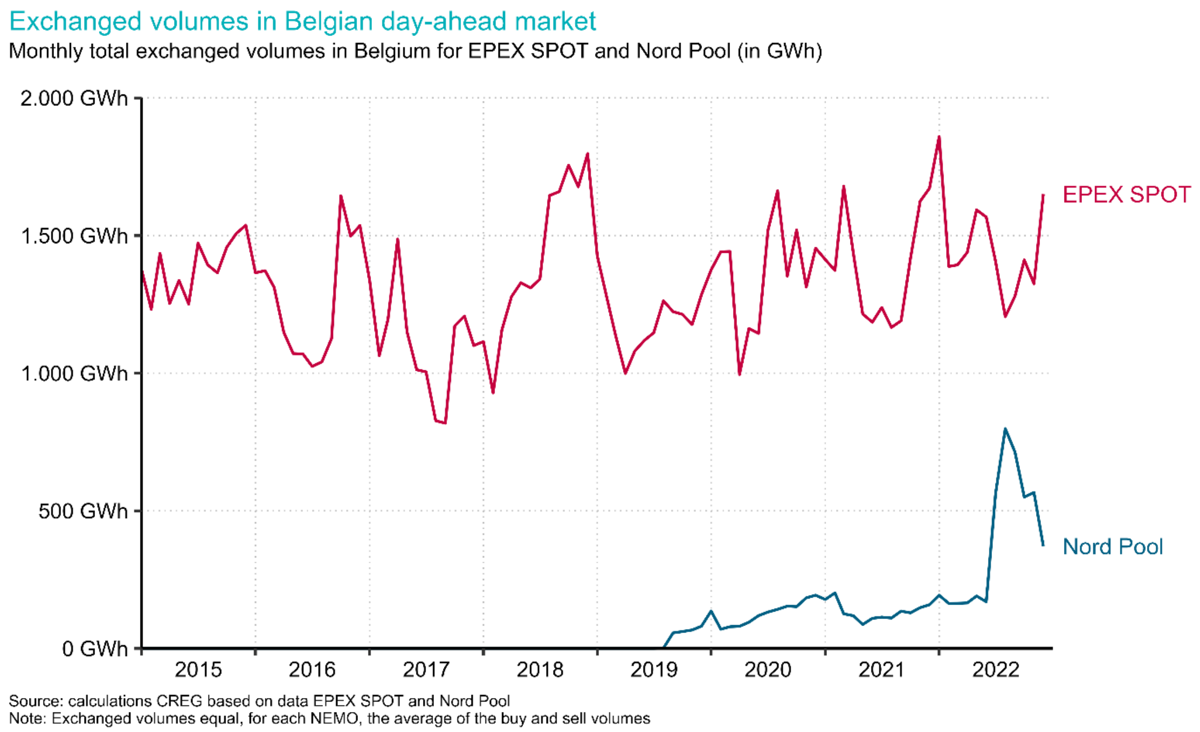
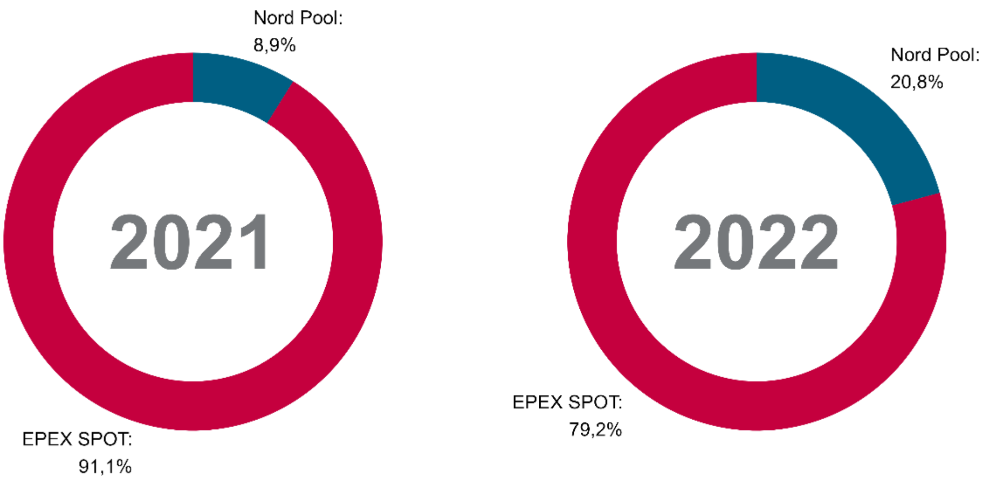


Figure 5-2 Exchanged volumes in Belgian day-ahead markets

92. After entering the Belgian market (as well as those of other CWE bidding zones) mid 2019, exchanged volumes on the Nord Pool exchange remained relatively stable until mid-2022, as can be observed from Figure 5-2. In those 2,5 years, the market share of Nord Pool was around 10% of the total exchanged volume in the Belgian bidding zone.[21] Since July 2022, the exchanged volumes increased strongly, leading to a high increase in the market share of Nord Pool. For EPEX SPOT, the incumbent NEMO, the exchanged volumes are fluctuating around the same order of magnitude, between 1.500 and 2.000 GWh per month. These observations combined led market shares of around 80% for EPEX SPOT and 20% for Nord Pool in 2022 (see also Figure 5-3).

[21] Exchanged volumes per NEMO are considered as the average of the buy and sell volumes for each hour, in order to ensure consistency between the way these data are reported by both NEMOs.

Market share of NEMOs in Belgian day-ahead market
Share of exchanged volumes per NEMO in Belgian day-ahead market, in % of total volume, in 2021 and 2022



Source: calculations CREG based on data EPEX SPOT and Nord Pool
Note: Exchanged volumes equal, for each NEMO, the average of the buy and sell volumes

Figure 5-3 Market share of NEMOs in Belgian day-ahead market

93. The total exchanged volume, counted as average of the buy and sell volumes of both NEMOs, reached 22,1 TWh in 2022. This represented an increase with 21,4% compared to 2021, when this number was only 18,2 TWh. This means that a little more than a quarter (27,0%) of the Belgian electricity consumption (81,7 TWh, see also chapter 1) was traded on the coupled day-ahead market.

5.1.2. Cross-border net positions

94. The net position of a bidding zone is determined by the market coupling process through the *Euphemia* algorithm. The evolution of this net position[22] is shown, for Belgium, in Figure 5-4. The observed monthly averages (blue line) as well as the highest and lowest observed net positions (shaded area) were, in 2022, in line with the observations since early 2019, with a slight increase in the export direction. Throughout 2022, monthly average import net positions were observed only in February (51 MWh/h) and March (471 MWh/h). During these months, high volumes were imported from the Netherlands (in March) and Germany (both in February and March) as average prices in Belgium were significantly above those in these countries.

[22] Since the Brexit and the departure of the Great Britain bidding zone from the Internal Energy Market on 1 January 2021, exchanges over the Nemo Link interconnector are no longer included in this "SDAC net position".

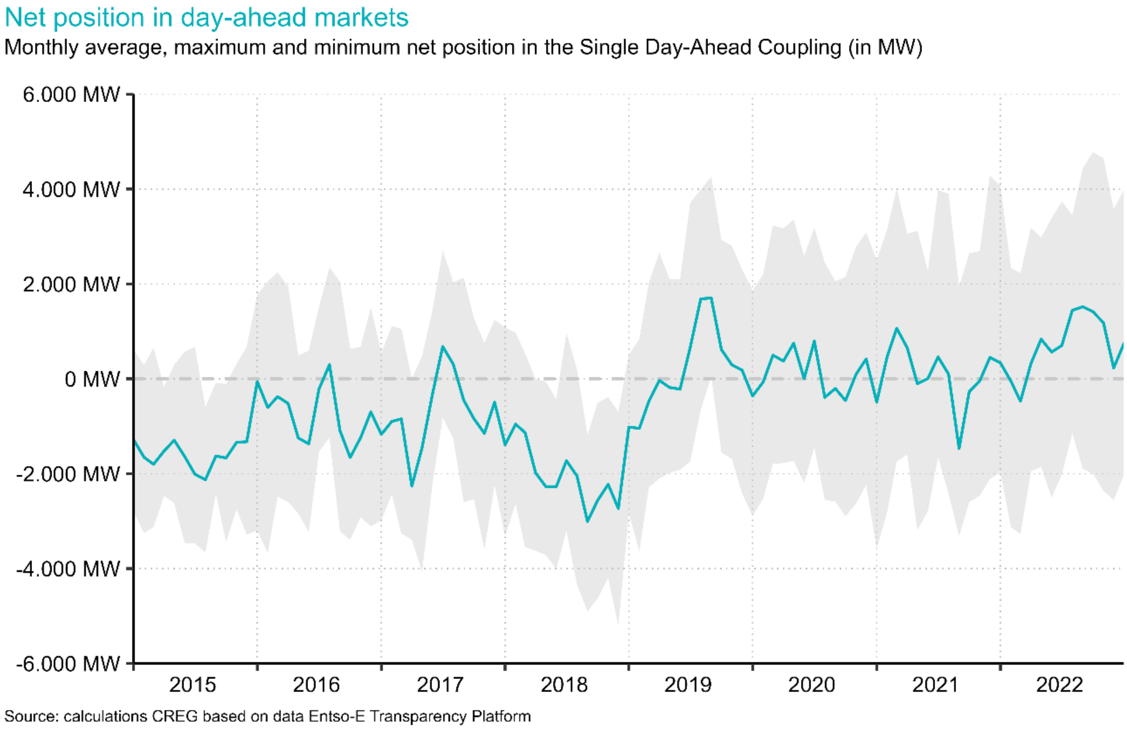


Figure 5-4 Net position in day-ahead markets

95. Table 5-1 recalls the global net position of Belgium in the SDAC on a yearly basis. In 2022, just as the three years before (since 2019) a net export position was achieved. A record-high net exporting position has been observed on 19 October 2022, reaching 4.780 MW. These numbers follow the long-term trend since 2015, were after years of importing very big volumes in the day-ahead timeframe (reaching a peak of 2.030 MW on average in 2018), Belgium became a structurally exporting country.

(in MWh/h)	2015	2016	2017	2018	2019	2020	2021	2022
Average net position	-1.607	-728	-736	-2.030	189	123	70	673
Maximum net position	683	2.348	2.702	1.084	4.262	3.357	4.289	4.780
Minimum net position	-3.656	-3.668	-4.069	-5.196	-3.630	-2.892	-3.581	-3.273

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

Table 5-1 Evolution of yearly average, maximum and minimum net position of Belgium in the SDAC

96. The global SDAC net export position in 2021 was remarkable, given the omission of the data for the exchanges between Belgium and Great Britain. As has been shown in the previous version of the Monitoring Report[23], adding the high export volumes led to a net export position of 959 MW (as the exports over the Nemo Link interconnector reached 889 MW in 2021. In 2022, a more balanced position was observed on this border: the average net position on BE – GB was 48 MW in the export direction, leading to a total net export position of Belgium (SDAC + GB-BE) of 721 MW.

[23] Monitoring Report 2021, paragraph 87 and section 5.1.3

5.1.3. Post-Brexit trading arrangements

97. The withdrawal of the United Kingdom from the European Union and the Internal Energy Market has been mentioned before. Since 1 January, capacities on the Nemo Link interconnector are no longer allocated through the SDAC (or SIDC for the intraday timeframe) processes, but via an explicit allocation process, consisting of:

i. the purchasing of day-ahead transmission capacity rights via JAO

ii. the buying or selling of energy in one of the two day-ahead electricity auctions (via Nord Pool or EPEX SPOT) for delivery in Great Britain;

iii. the buying or selling of energy in the SDAC auctions (accommodated in Belgium by Nord Pool or EPEX SPOT) for delivery in Belgium (or other coupled bidding zones); and

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

98. The inefficiency resulting from the complexities introduced by this process, compared to the implicit SDAC coupling, has been described and assessed in the previous Monitoring Report.[24] The occurrence of market participants exchanging energy against the market spread, resulting from wrong forecasts of the relative price levels in Belgium and Great Britain, is shown in Figure 5-5 (i.e. the observations in the upper right and lower left quadrants). In these quadrants, flows go from the higher-priced to the lower-priced zones. While such hours were rather rare in 2019 and 2020, they increased in 2021 and even more so in 2022. These inefficiencies seem to increase when the price spread levels get smaller, as the relative differences become more difficult to forecast correctly, or when within-day flow reversals occur (which are more difficult to profile for market participants).

99. The values of these flows (against or with the market spread) are calculated in Table 5-2 as the product of the exchanged volumes (i.e. the day-ahead commercial schedules) and the price spread between both markets.[25] As was shown in the previous figure, the number of hours with flows against the market spread increased strongly after the introduction of the explicit coupling mechanism on 1 January 2021. This increased even further in 2022, to about one fifth of the total hours, at a total value of more than 13 M€. The increase between 2021 and 2022 results from the more balanced position of both markets: while in 2021 a structural export position was obvious for Belgian market participants, the relative price levels have been more volatile (and, on average, balanced) in 2022, leading to more wrong forecasts. This sum clearly constitutes a welfare loss, introduced by the inefficiency of the explicit trading mechanism compared to the implicit mechanism, despite the best efforts of the involved parties (including Nemo Link) to allow for more efficient trading opportunities for market participants.

[24] idem

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

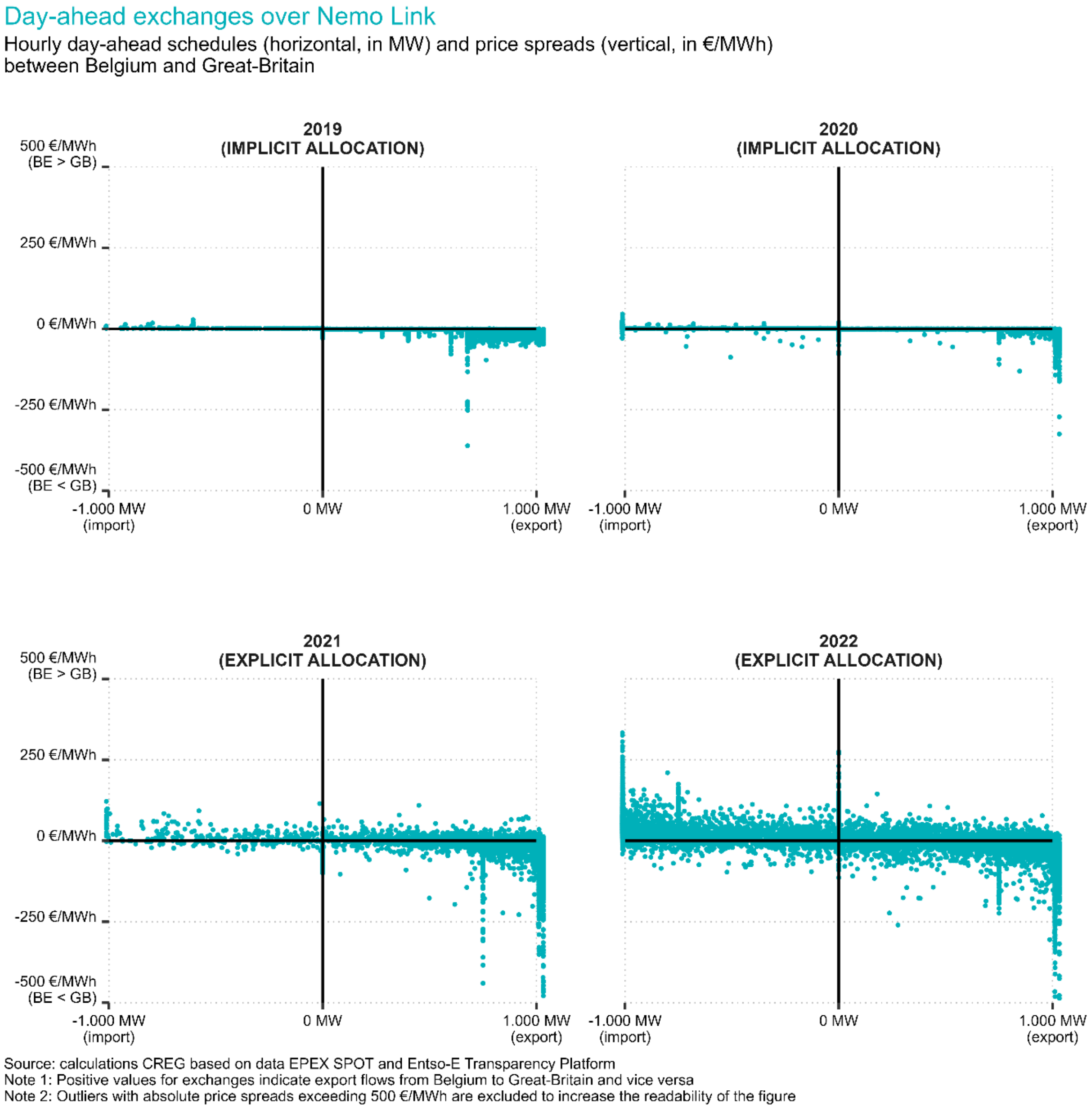


Figure 5-5 Day-ahead exchanges over Nemo Link

	2019	2020	2021	2022
% of hours with exchanges against the market spread	0,0%	0,5%	11,2%	20,1%
Value of exchanges against the market spread (exchange * price spread)	598 €	392.653 €	5.633.362 €	13.098.245 €
Value of exchanges with the market spread absolute value of (exchange * price spread)	62.793.567 €	72.070.772 €	301.275.236 €	345.641.919 €

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

Table 5-2 Occurrence and values of exchanges against the market spread on Nemo Link

5.2. PRICES

100. Figure 5-6 shows the long-term evolution of the monthly average day-ahead prices in Belgium and its neighbouring bidding zones (Great Britain[26] and other CWE bidding zones). Following the all-time low values in 2020 as a result of the measures against the worldwide COVID-19 pandemic, prices in all considered bidding zones started picking up towards the end of 2020. Fueled by drastically changing market fundamentals, both in terms of costs of the input factors (gas, CO_2) as well as related to supply and demand), prices have reached historically high levels from the second half of 2021 and, more importantly, throughout 2022.

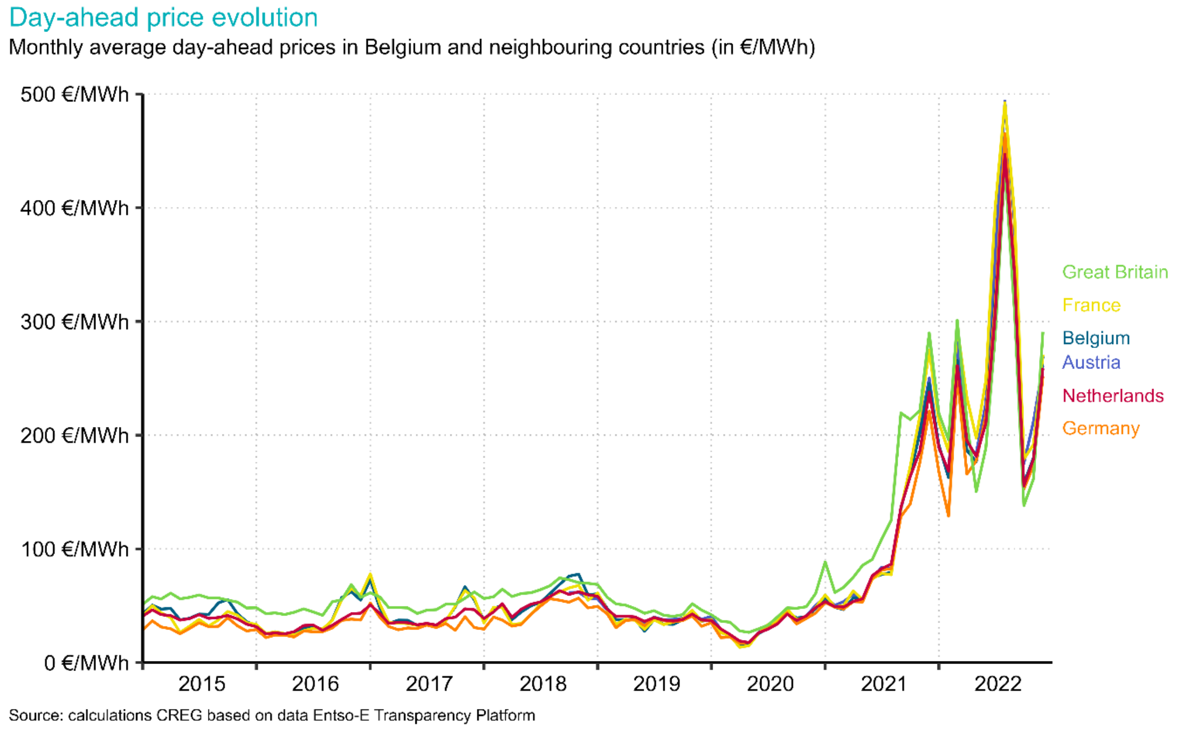


Figure 5-6 Day-ahead price evolution

101. The average price across all hours of 2022 reached 244,5 €/MWh in Belgium, more than double the value of 2021 (104,1 €/MWh) and six times higher than the historical average observed between 2015 and 2020 (42,1 €/MWh). This increase is significantly below the values for other countries, as shown in Table 5-3, with the exception of Great Britain, even though this is partly due to the relative position of the historical prices in Belgium (and Great Britain) over other countries. The extremely high observed increases (between +367% and +584%) obviously have a very negative impact on electricity consumers and their ability to pay their electricity bills. This provides the background for the many policy initiatives taken, on Belgian and European level, to redistribute some of these earnings, or decouple the wholesale price evolution from retail prices, yet these initiatives are out of scope of this study.

[26] As mentioned earlier, two exchanges are active in Great Britain. In the absence of a single reference price, the clearing price on the EPEX SPOT platform are shown.

	Historical price (avg. 2015 - 2020)	Avg. 2021 price	Avg. 2022 price	2022 increase compared to historical
Austria	39,2	106,9	261,4	+567%
Belgium	42,1	104,1	244,5	+481%
France	40,3	109,2	275,9	+584%
Germany	34,6	96,8	235,4	+581%
Great Britain	51,7	137,7	241,6	+367%
Netherlands	39,6	103,0	241,9	+511%

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

Table 5-3 Increase of yearly average day-ahead price compared to historical average

99. Despite the consistently high price levels throughout 2022, the evolution throughout the year is shown by using a 7-day rolling average for Belgium and its neighbouring countries in Figure 5 5. By focusing on the last year, it becomes apparent that three periods with major price peaks can be observed:

- **Early March**: following the Russian invasion in Ukraine, average prices shortly rose to 400 €/MWh, fuelled by a strong and rapid increase in prices for natural gas and coal, despite a very strong reduction of prices for CO2 (EUA allowances).
- **End August**: as a result of extraordinary meteorological circumstances, the supply of electricity has been strained in several European Member States, due to the unavailability of several nuclear (France), lignite (Germany) and hydro generation units (central Europe and the Nordics). In combination with high natural gas and coal prices, this led to the highest electricity prices ever observed (between 600 – 700€/MWh on average).
- **Early-mid December**: colder than average weather combined with unfavourable wind conditions (leading to low generation from on- and offshore wind), combined with increasing CO2 prices, led to electricity prices reaching again, on average, 400 €/MWh.

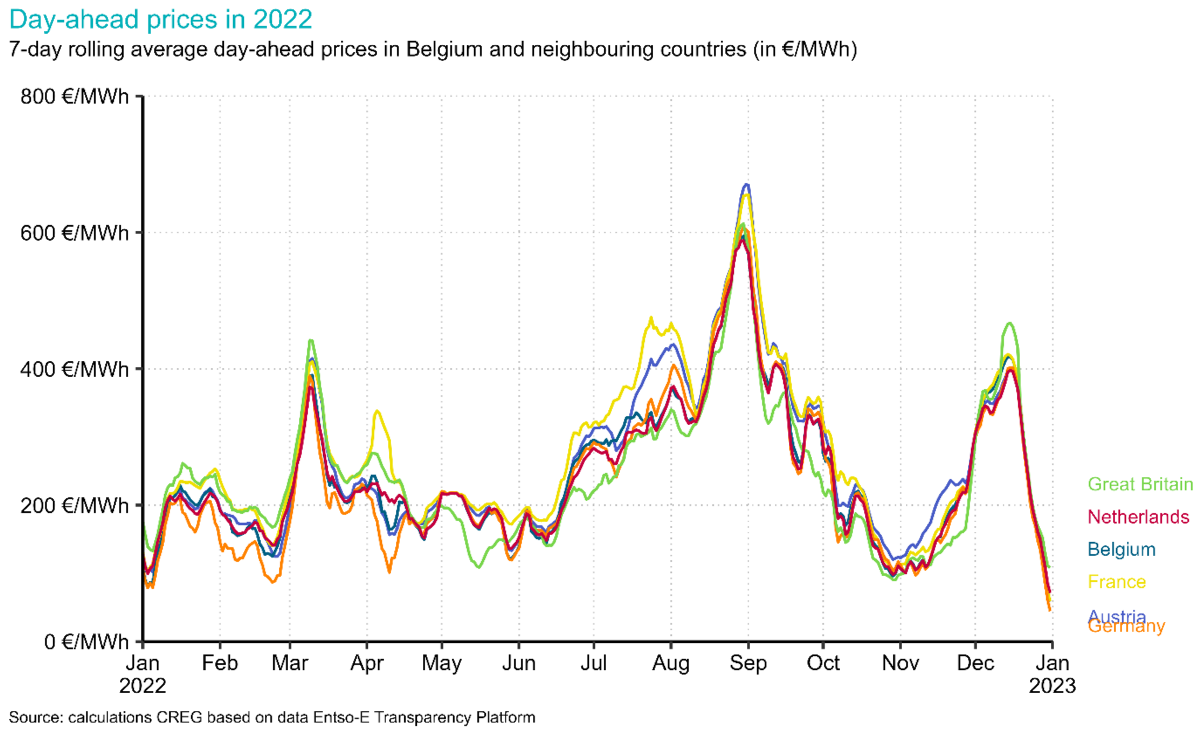


Figure 5-7 Day-ahead prices in 2022

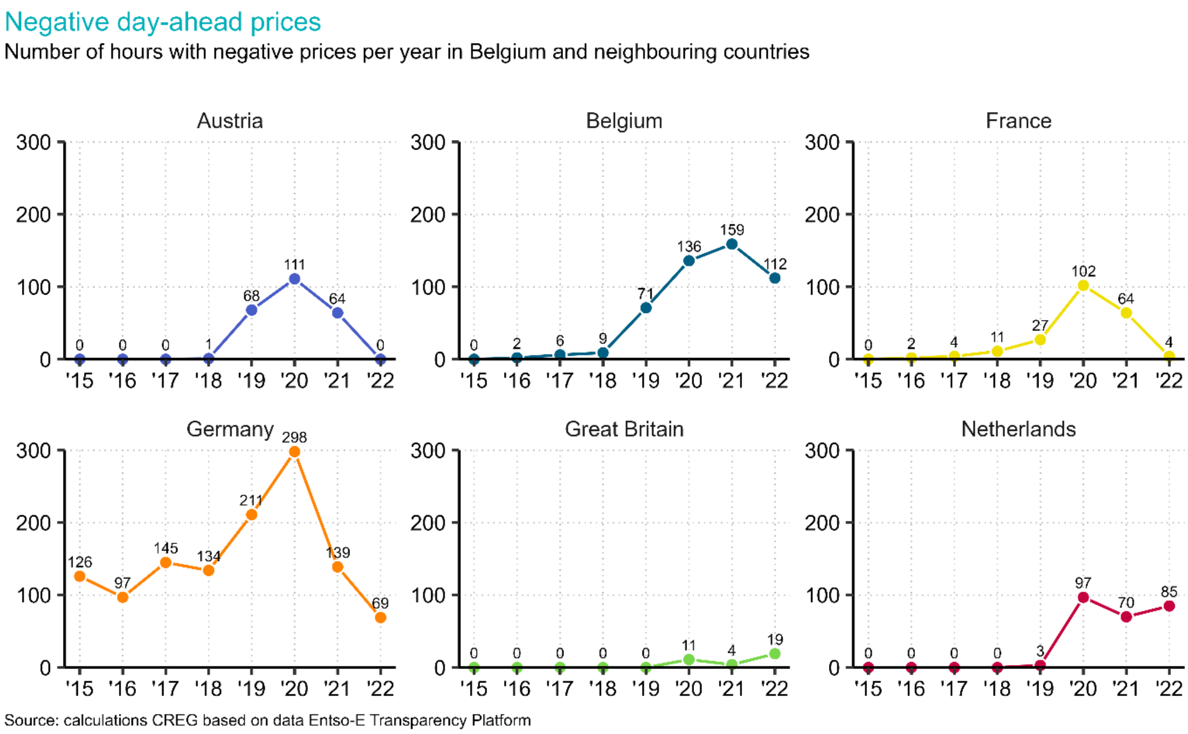


Figure 5-8 Negative day-ahead prices

102. Belgium remained, in 2022 just as in 2021, the bidding zone with the highest count of hours with negative prices in Europe. During 112 hours (1,3% of the year), the clearing price on the Belgian coupled day-ahead market was negative. This is a decrease compared to 2021 (159 hours). In many neighbouring countries, such as Austria, France and Germany, the number of hours with negative prices decreased strongly – modest increases were observed only in the Netherlands and Great Britain.

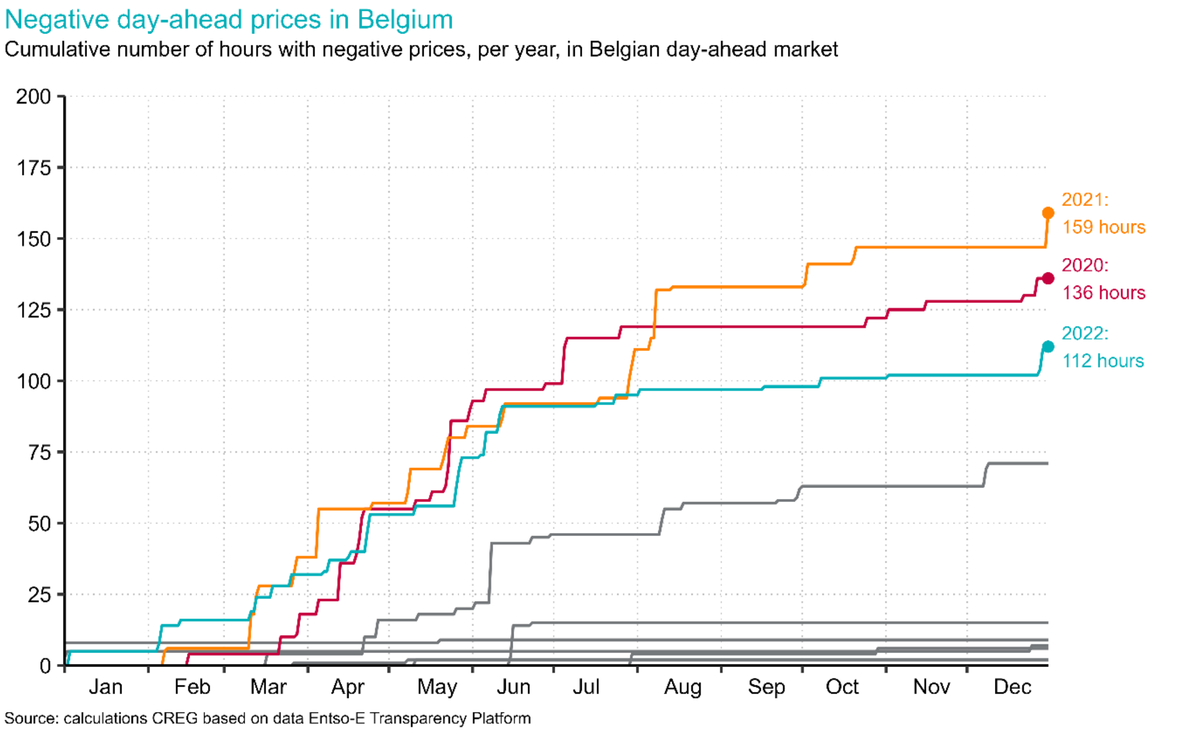


Figure 5-9 Negative day-ahead prices in Belgium

103. Most of the negative day-ahead prices occur in the months of April and May, and to a lesser extent in March and June, as can be seen in Figure 5-8. These are typically longer days, with high renewable generation (mostly solar PV but also wind). Interestingly, the last years an increase in the number of hours in the last days of the year has been observed. These occurrences correspond to the Christmas break, where – despite low solar production – the combination of very low demand (due to the holiday season) and potentially high wind generation drives negative prices.

104. Complementing the view on the evolution of yearly and monthly average prices, shown before, Figure 5-10 shows, for each country, the yearly distribution of the observed day-ahead prices. It is clear that for Belgium, but similarly for other ones, the density curves shift strongly to the right in 2021 and 2022 compared to the previous years, becoming much flatter and spread out between the extremes. This indicates that prices tended to increase (a lot): both the average values as well as the high and low values tended increase, while the occurrence of the very high prices increased as well.

105. Not all observed prices are shown: the view is limited to those hours where prices between -50 €/MWh and 600 €/MWh are observed. In several bidding zones, during some hours, much higher prices than 600 €/MWh materialized.[27]

[27] The highest observed price equaled 2.987,8 €/MWh, just below the maximum clearing price of 3.000 €/MWh, on 4 April 2022 at 8:00.

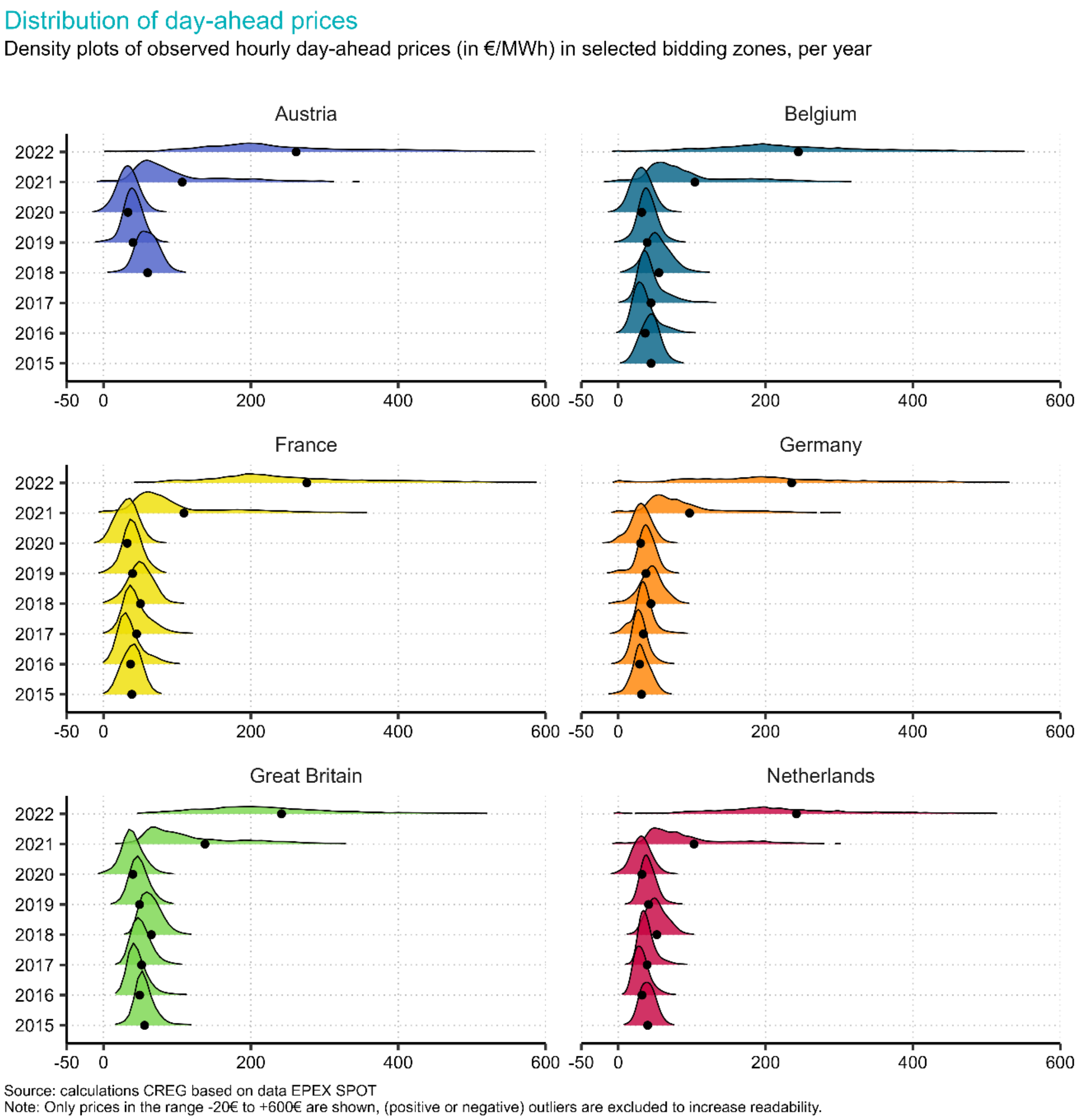


Figure 5-10 Distribution of day-ahead prices

5.3. PRICE CONVERGENCE AND SPREADS

106. When the transmission network is capable of accommodating all requests for cross-zonal capacity between bidding zones, prices converge as import and export are directing flows from low-priced zones to high-priced zones. This is called price convergence and is typically considered as an important metric to measure market integration.

107. The historical evolution of the yearly (orange) and monthly (blue) average levels of price convergence (expressed as a percentage of hours in that month) is shown in Figure 5-11.[28] Following the introduction of the CWE FBMC in May 2015, the time series show a seasonal cycle with more convergence in summer than in winter. Convergence levels started increasing in 2019, continuing until 2021. From the last three months of 2021 onwards and throughout 2022, however, convergence levels decreased strongly. The 2022 average convergence rate equaled only 34,9% of all hours (compared to 49,6% in 2021).

108. Table 5-4 shows the yearly percentages of hours with price convergence, either between Belgium and one neighbouring bidding zone, or with all (former) CWE bidding zones in total. For each individual border, a significant decrease in the share of hours with convergence is observed, especially on the Belgian – French border (from 59,9% in 2021 to 40,1% in 2022). The decrease is less pronounced when considered between all CWE zones.

	2015	2016	2017	2018	2019	2020	2021	2022
BE = FR	51,0%	63,3%	54,0%	49,5%	60,5%	65,4%	59,9%	40,1%
BE = NL	52,2%	51,1%	52,7%	51,6%	58,0%	65,5%	58,1%	43,8%
BE = DE	22,4%	44,0%	41,8%	39,8%	52,8%	58,2%	56,0%	42,1%
CWE convergence	20,9%	38,5%	37,5%	35,6%	45,9%	48,5%	49,5%	34,9%

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

Table 5-4 Yearly partial and full convergence levels

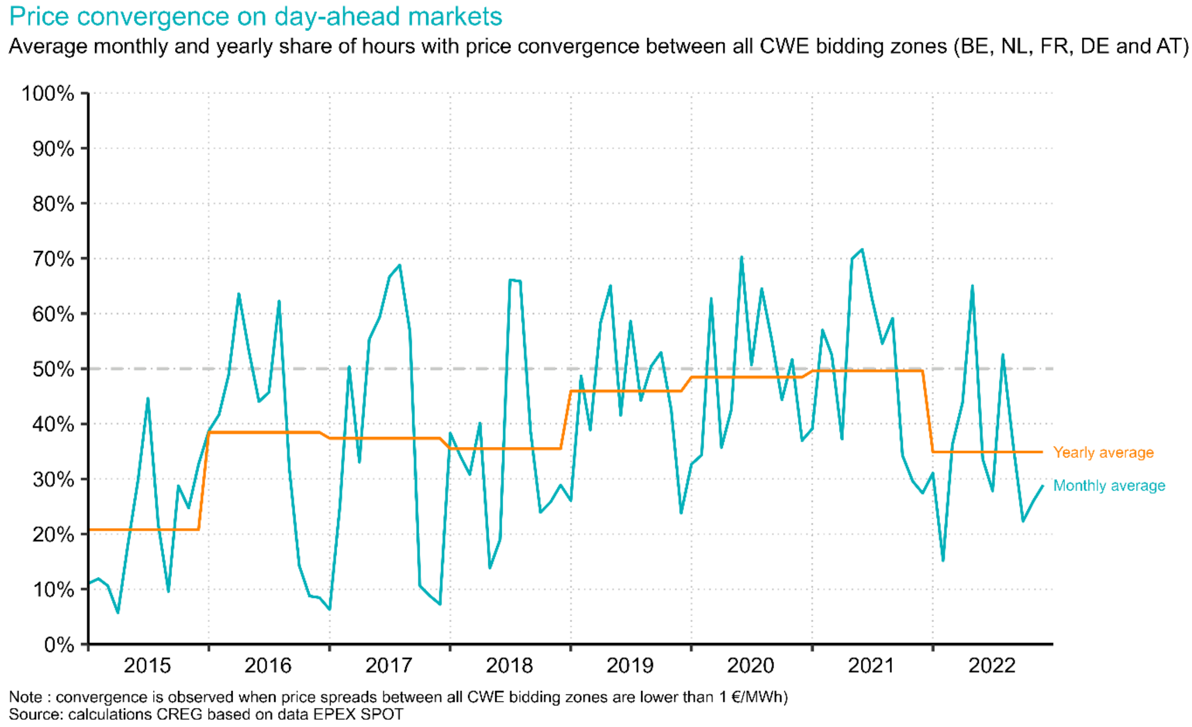


Figure 5-11 Price convergence on day-ahead markets

[28] In the remainder of this section, price convergence is defined as the situation where prices between all considered bidding zones do not exceed 1 €/MWh.

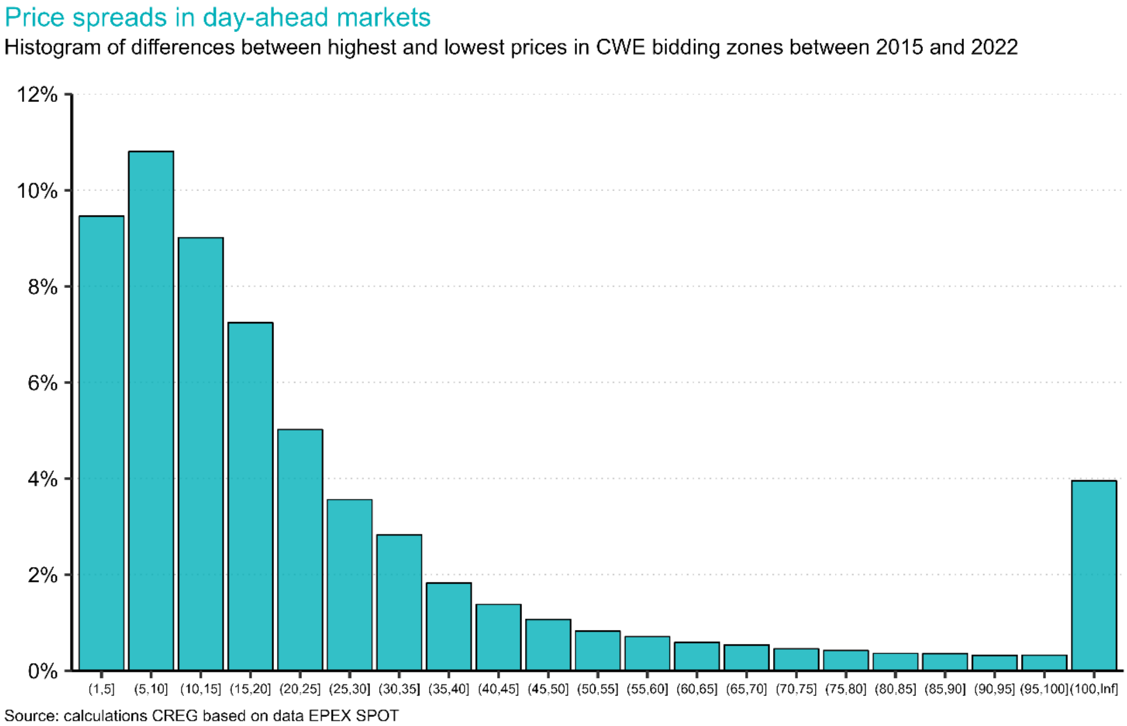


Figure 5-12 Price spreads in day-ahead markets

109. The difference between the highest and lowest price between Belgium, the Netherlands, France, Germany and Austria (defined as the price spread in Figure 5-12) are generally (44,4% of the time[29]) below 5€/MWh. Even though price spreads occur most often in the range between 5 and 10 €/MWh, higher price spreads are observed as well. At the far right side of the histogram, it may be observed that price spreads exceeding 100 €/MWh occur in 4,0% of all hours between 2015 and 2022 – this is a strong increased to last year, when this was still “only” 1,2% of all hours between 2015 and 2021, indicating that a lot of these hours have been observed last year.

[29] Including 34,9% of the hours where the price spread does not exceed 1 €/MWh, defined as “price convergence”.

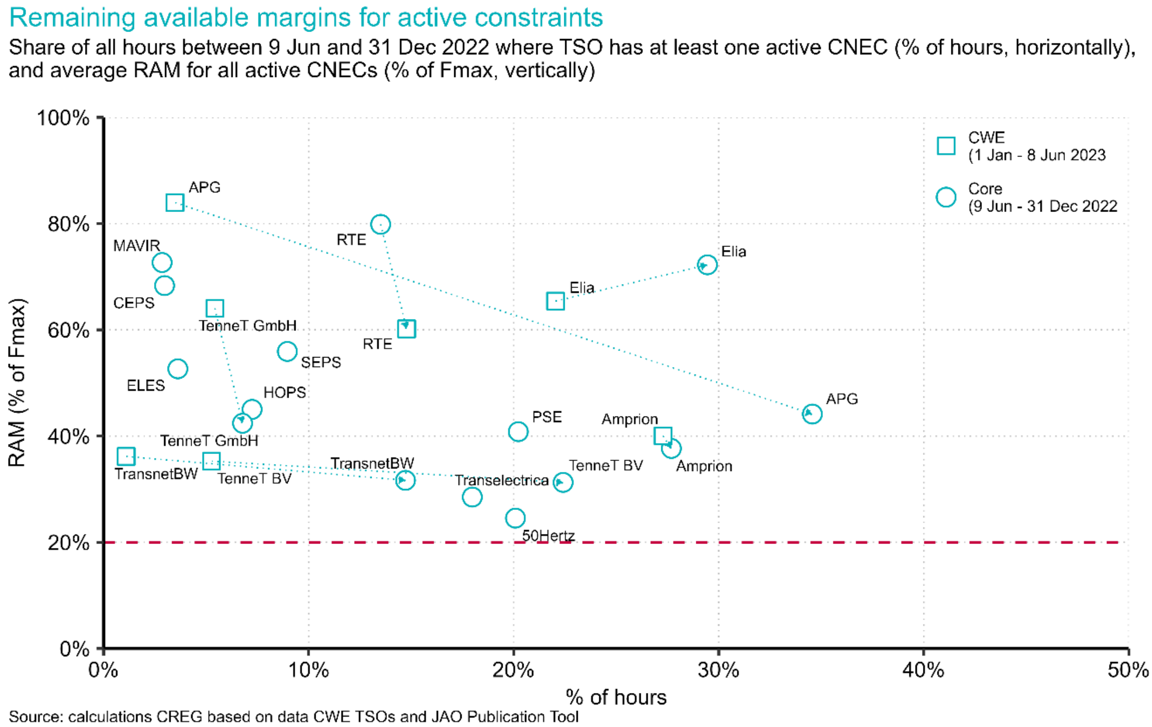


Figure 5-13 Remaining available margins for active constraints

110. In flow-based market coupling mechanisms (either in CWE or in Core), congestion is caused by the inability of specific transmission network elements to accommodate all cross-zonal exchanges which are desirable from a welfare-maximization point of view. Technically speaking, these are the “active constraints” which limit the market outcome. Figure 5-13shows how often TSOs’ network elements are active (x-axis), and the margins available for exchanges in the CWE or Core FBMC (y-axis).

111. It is clear that substantive differences may be observed according to the considered TSO. For TSOs which were also part of the CWE FBMC, two observations are plotted (one prior to the Core FBMC go-live, labelled “CWE”, and one post go-live, labelled “Core”) and a dotted arrow links these two observations. As a reference, the 20% minRAM requirement is included as a dashed red line. Of all the considered CWE TSOs, only Elia has shown an increase in the average RAM value on its active constraints (even though active constraints were observed more often): other CWE TSOs (in particular AGP, RTE and TenneT GmbH) have shown strong reductions in the available margins when network elements were active.

112. Low margins available for cross-zonal exchanges are obviously a cause for concern, in particular when these are observed on active network elements. This implies that the inability of TSOs to accommodate higher exchanges has a clear impact on socio-economic welfare. The associated shadow price of these active constraints (not shown) calculates this impact: the higher the shadow price, the higher the welfare loss.

5.4. CAPACITY CALCULATION

5.4.1. Minimum and maximum net positions

113. The maximum export and import positions of a bidding zone in the CWE and Core FBMC framework give an indication of the transmission capacity which is available for cross-zonal trade from the Belgian to other coupled (CWE or Core) bidding zones. It is obtained by taking a cross-section of

the union of the multi-dimensional flow-based domain and bilateral exchange restrictions, and describes how much capacity is provided to the market coupling. Given the assumptions taken in the calculation of the domains (i.e. all other net positions are in balanced position, i.e. with net export equalling 0 MW) it is a theoretical indicator, yet its evolution is useful to show some methodological improvements to the capacity calculation process.

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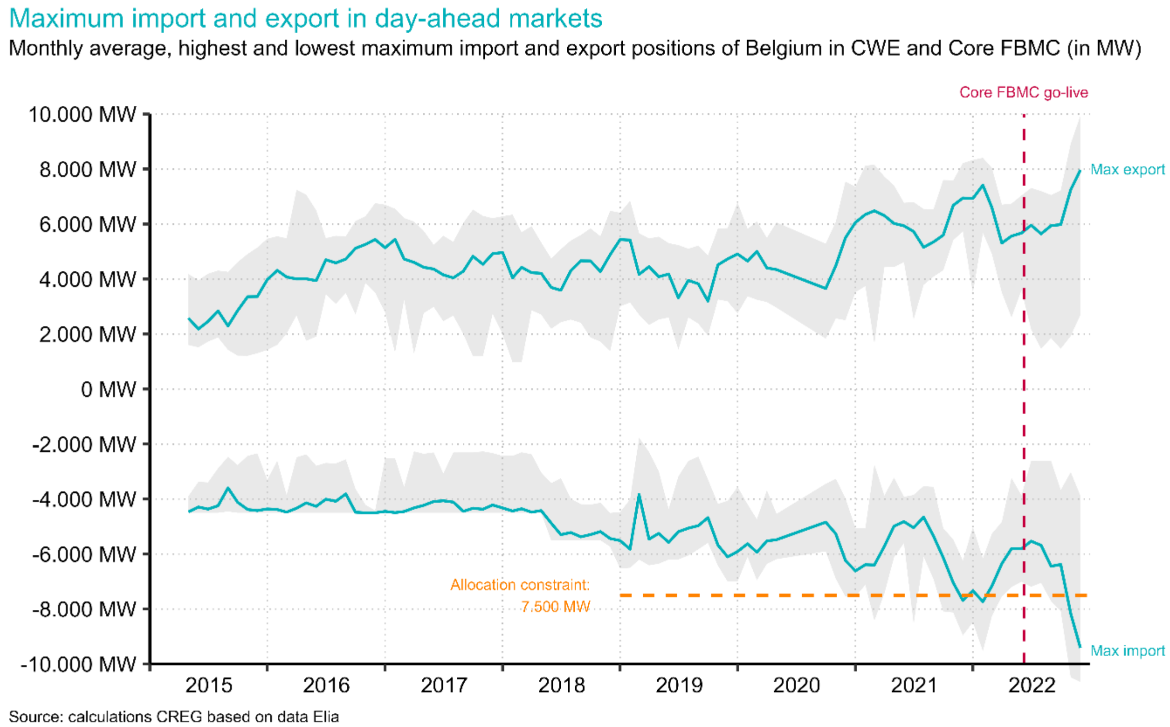


Figure 5-14 Maximum import and export in day-ahead markets

115. Until mid-2018, the maximum Belgian import was restricted to 4.500 MW through the application of an external constraint, related to maintaining the dynamic voltage stability of the network. This external constraint increased to 5.500 MW for the second half of 2018 and even further, to 6.500 MW, from 2019 onwards. Today, the dynamic voltage stability constraint is implemented as an allocation constraint, hence maximum import capacity levels exceeding 7.500 MW (the current value) are reported, even though the *Euphemia* algorithm does not allow that these values are allocated (shown by the orange line in Figure 5-14).

116. In 2022, the maximum positions increased further compared to the previous years in both the import and export direction. In November 2022, a strong increase in the maximum export and import positions has been observed, as a direct consequence of the completion of the Avelgem – Avelin

project, whereby existing lines on the interconnection with France were upgraded between 2018 and 2022. This upgrade allows physical exchanges on the border with France to reach up to 6 GW.[30]

5.4.2. Remaining available margins and CEP compliance

117. In this subsection, margins available for cross-zonal exchanges are presented. Two indicators are included: the RAM or Remaining Available Margin, and the MACZT or Margin Available for Cross-Zonal Trade:

- the RAM is mostly used in the context of the Core FBMC, and indicates the margin available for exchanges between Core bidding zones. According to the relevant ACER Decision and subject to exceptions under specific circumstances, a minimum RAM of 20% should be ensured.
- the MACZT is mostly considered for compliance purposes, to assess whether or not TSOs respect the so-called "70%-criterium" (Article 16 of the Electricity Regulation), which is the minimum capacity requirement, again subject to exceptions under specific circumstances (i.e. national action plans or derogations).

118. The results calculated for the different types of network elements (either cross-border, internal or phase-shift transformers) are shown in Table 5-5). A more thorough analysis of the results shown below, including the context under which these margins were observed, has been published by the CREG in the yearly "MACZT compliance reports". After an initial decrease in 2021, the compliance score of Elia increased again from 62,2% of the time to 79,1% of the time in 2022, indicating that during one fifth of all hours the minimum margin, taking into account the loop flow derogation, was not respected.

	2020		2021		2022	
	All network elements	Per hour	All network elements	Per hour	All network elements	Per hour
Cross-border	99,8%	95,0%	99,7%	90,9%	99,8 %	88,9%
Internal	98,8%	77,2%	99,0%	50,6%	99,7%	77,7%
PST	99,7%	97,0%	99,6%	86,9%	99,8%	70,0%
Global compliance	**99,2%**	**81,3%**	**99,2%**	**62,2%**	**99,7%**	**79,1%**

Source: calculations CREG based on data Elia

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

119. The impact of loop flows on network elements, which is a crucial parameter in the calculation of the compliance by Elia with the minimum margin requirements, is explored further in section 5.4.4sub. This impact is explained by the derogation which the CREG approved, for the year 2022, to deal with excessive loop flows preventing Elia from offering 70% of the capacity on all network elements.

[30] https://www.elia.be/en/infrastructure-and-projects/infrastructure-projects/avelgem-avelin

120. One particular element which is relevant in the context of the go-live of the Core DA FBMC Project, is the occurrence of violations of the 20% minRAM principle (see also paragraph 117). This lower threshold for the margin available for intra-Core trades is determined by ACER in its applicable decision, and prescribes that the RAM value (*Remaining Available Margin*) should at least be equal to 20% of the F_{MAX} or the maximum admissible power flow on a network element. This margin is proposed to ensure the non-discriminatory allocation of transmission capacity. In specific circumstances, however, TSOs are allowed to apply validation reductions (see next section) leading to lower margins.

121. Figure 5-15 shows the distribution of the available margins (RAM) per CNEC and the averages per TSO in the Core FBMC, between 9 June and 31 December 2022. Table 5-6shows how often (both in terms of individual hours as well as in terms of individual network elements) the 20% minRAM threshold is violated, and the average RAM (also shown in the figure) per TSO.[31]

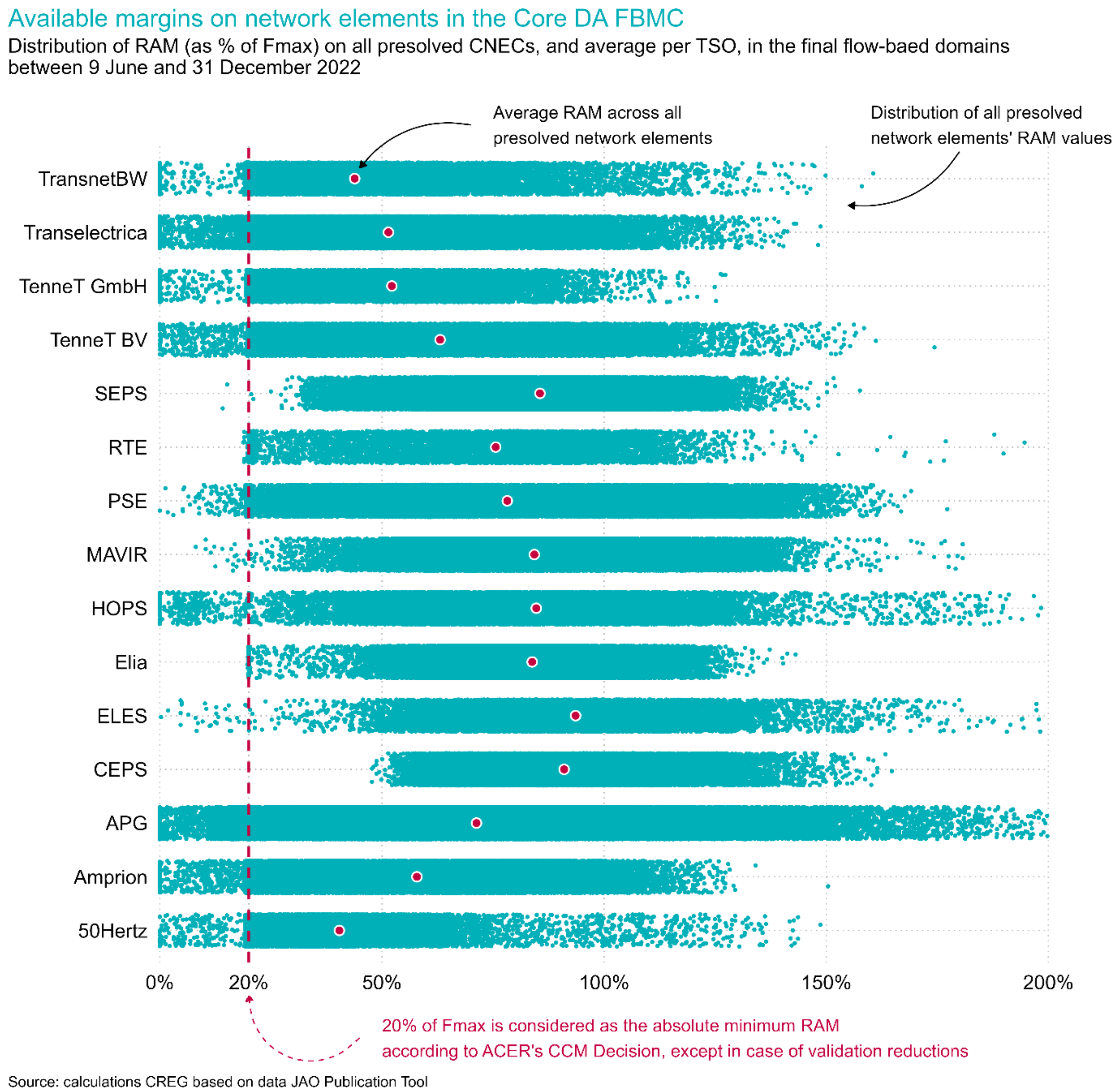


Figure 5-15 Available margins on network elements in the Core DA FBMC

[31] Rather than evaluating whether RAM / F_{MAX} exceeds 20%, the flows resulting from long-term nominations (F_{LTN}) and a margin to avoid rounding errors of 3 MW are added to the RAM. This practice is commonly agreed in the Core DA FBMC.

	Violations of the 20% minRAM threshold		Average RAM (globally)
	Number of distinct MTUs	Number of distinct CNECs	
50Hertz	1,7%	186	40,4%
Amprion	2,1%	421	57,9%
APG	3,1%	902	71,3%
CEPS	0,0%	0	91,0%
ELES	0,0%	0	93,6%
Elia	0,0%	0	83,8%
HOPS	1,4%	79	84,7%
MAVIR	0,1%	6	84,3%
PSE	1,7%	95	78,2%
RTE	0,0%	0	75,6%
SEPS	0,1%	3	85,6%
TenneT BV	1,8%	358	63,1%
TenneT GmbH	1,2%	244	52,2%
Transelectrica	11,4%	1031	51,4%
TransnetBW	1,2%	181	43,9%

Source: calculations CREG based on data JAO Publication Tool

Table 5-6 Violations of the 20% minRAM threshold and average RAM per TSO

122. The striking differences between the TSOs result from different applications of the individual validation approaches. This topic has already been the subject of a dedicated study of the CREG, published in September 2022, where concerns were raised with regards to the discriminatory impact of these non-transparent reductions in available capacity.[32] At the moment of writing, the CREG is actively advocating for the consideration of the 20% minRAM threshold as an absolute minimum, even when validation adjustments need to be applied.

5.4.3. Validation reductions and allocation constraints

123. The study referred to in paragraph 122 clearly demonstrates the distortive impact of two individual, ad hoc measures which TSOs can resort to in case the coordinated outcome of the capacity calculation process needs to be altered. These are so-called individual validation adjustments (IVA, see also previous section) and allocation constraints.

124. Through the application of individual validation adjustments, Core TSOs have the right to – under specific circumstances related to the need to maintain operational security standards – validate and correct cross-zonal capacities. The application of these IVAs effectively reduces the available margins (RAM) on a critical network element, hence reducing the size of the flow-base domains and lowering the margins for cross-zonal exchanges. Figure 5-16 shows how often TSOs apply these IVAs (in % of all hours following the go-live of the Core DA FBMC Project) and how much they reduce the RAM (in % of F_{MAX}).

125. Some TSOs (for example Transelectrica and RTE, yet to a lesser extent also Elia and HOPS) apply IVAs fairly often (between 10% and 25% of all hours). These are, however, fairly small reductions (lower than 20% of F_{MAX}. The four German TSOs, as well as TenneT BV (Netherlands) and APG (Austria) apply reductions less frequently (in terms of time, less than 5%), yet the impact is much higher: when applied, these IVAS reduce the available margins with more than 40% (even up to 63% on average for TenneT GmbH).

[32] Study (F) 2458 on the functioning of the Core day-ahead flow-based market coupling mechanism and the impact of low margins available for cross-zonal exchanges

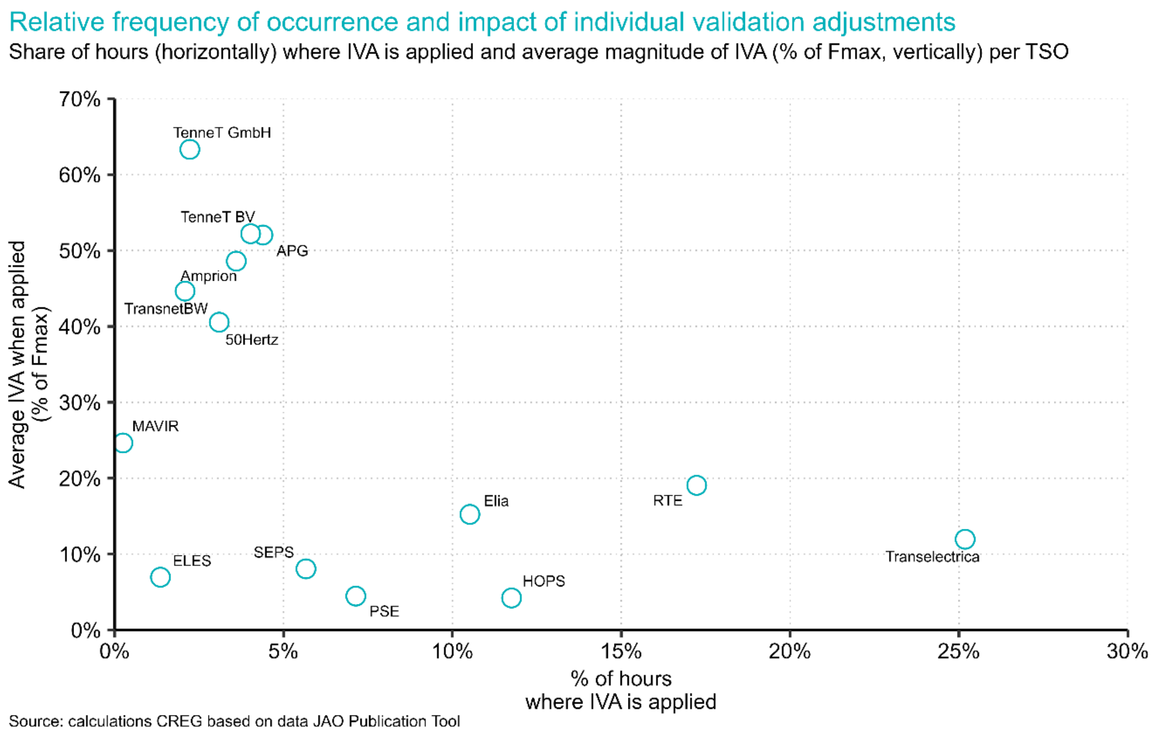


Figure 5-16 Relative frequency of occurrence and impact of individual validation adjustments

126. In the Core DA FBMC, allocation constraints are reported for Belgium (import) and Poland (both directions). Figure 5 13 shows the total share of hours in the Core DA FBMC (between 9 June and 31 December 2022) when an allocation constraint was active (coloured) or inactive (grey), per zone and direction. When an allocation constraint is active, three different situations are considered:

- The allocation constraint equals zero (red), indicating that the SDAC net position can only move in one direction: either import or export.
- The allocation constraint lies between zero and the max Core net position (orange), indicating that the maximum net position of the Core capacity calculation and allocation process (see also section 5.4.1) are effectively overridden by the allocation constraint.
- The allocation constraint exceeds the max Core net position (green), meaning that it is active yet not limiting the max net position in the Core DA FBMC.

127. The waffle chart below shows the very high share of hours where, in particular, the Polish SDAC export position is restricted and artificially set at zero (75,7%). This significantly impacts the ability of the Polish bidding zone to export to its neighbouring Core bidding zones. The Belgian import allocation constraint, currently set at maximum 7.500 MW, is very often active yet only in 57,0% of all hours does it really alter the max net position.

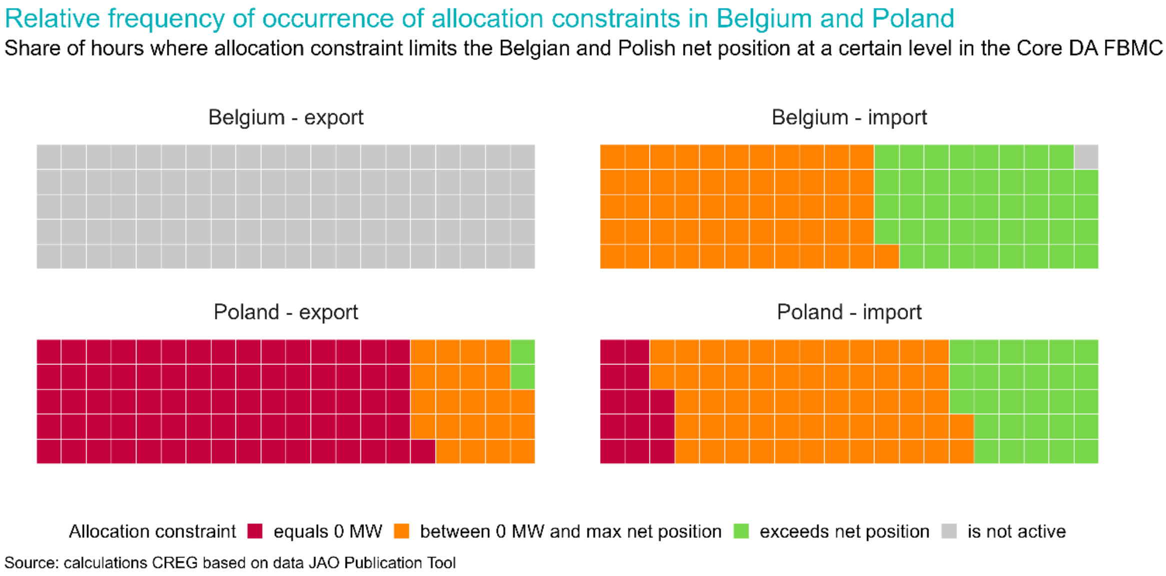


Figure 5-17 Relative frequency of occurrence of allocation constraints in Belgium and Poland

128. The application of IVAs and allocation constraints have a very negative impact on the available cross-zonal capacities resulting from the Core DA FBMC. The CREG will continue to monitor these parameters and insist that they shall not be used as instruments to unduly lower the available margins or restrict cross-zonal exchanges, as this discriminatory practice is against the spirit of a flow-based capacity calculation methodology as well as in contradiction with the objectives of the applicable European legislation.

5.4.4. Loop flows

129. Loop flows are observed on network elements within or between bidding zones, yet they arise from exchanges within another bidding zone. Hence, they are not within the immediate control of a TSO.[33] Since 2017, Elia publishes the loop flows present in the day-ahead capacity calculation process.[34]

130. In the Belgian transmission network, loop flows historically follow a structural north-to-south direction. They result mostly from exchanges within the German/Luxembourgish bidding zone, which is relatively speaking much larger than the Belgian bidding zone. In 2022, average monthly loop flows ranged between 16 MW (in August) and 997 MW (in February). This confirms the decreasing trend, observed since 2017, both in terms of average as well as in terms of maximum loop flows observed on a monthly basis. Given that these loop flows have priority access to the grid and thus limit cross-zonal exchanges, this decrease is a positive evolution for the CWE and Core FBMC (or for the day-ahead cross-zonal exchanges to and from Belgium). This evolution is shown in Figure 5-18.[35]

[33] Even though, as discussed further on, topological measures such as the setting of PSTs, exist to *"push back"* loop flows to a certain extent, coordinated between TSOs.

[34] Following the go-live of the Core DA FBMC Project in June 2022, this publication (formerly on the Open Data Platform, dataset ods027) has been replaced by a line-per-line calculation of loop flows on the JAO Publication Tool (in the Core FBMC capacity calculation datasets).

[35] Note: for practical purposes, positive loop flows are defined as going from north to south, while negative loop flows are going in the inverse direction: from south to north.

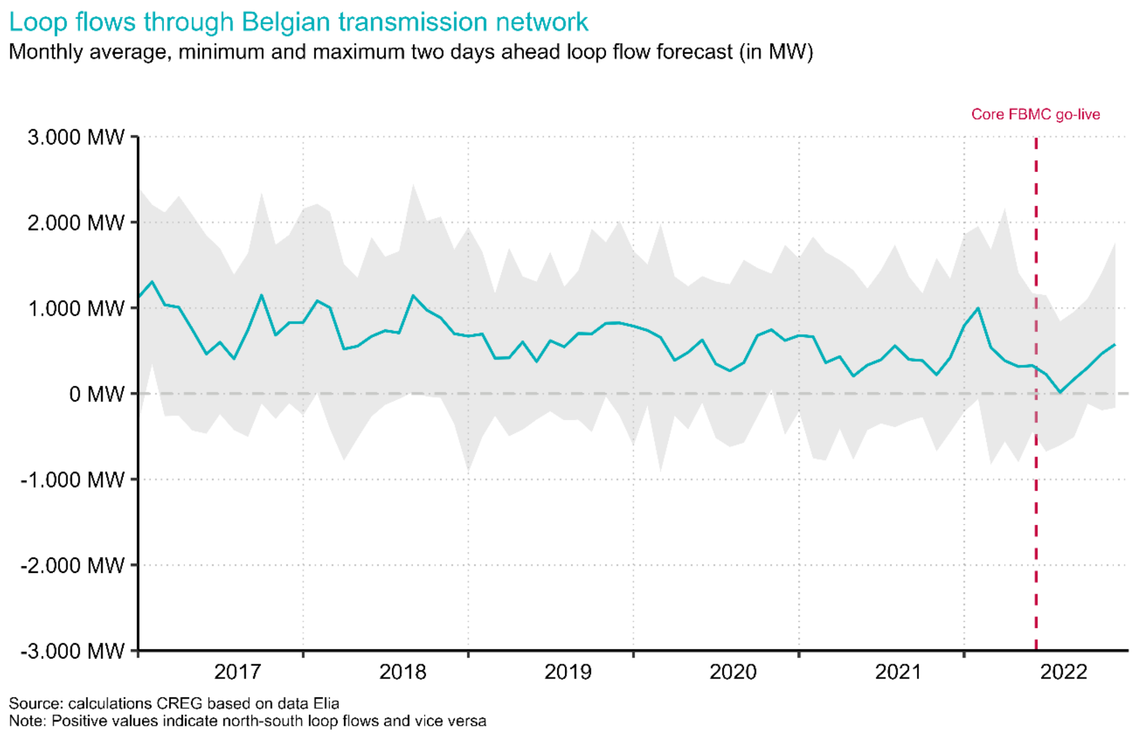


Figure 5-18 Loop flows through Belgian transmission network

131. The distribution of the observed loop flows between 2017 and 2022 confirms this observation about the structural direction: in 90,0% of all hours in 2022, these flows went from north to south. This observation is in line with the year 2021, but a decrease compared to 2017 – 2020. The evolution of this parameter is shown in Table 5-7.

	2017	2018	2019	2020	2021	2022
North to south	96,8%	97,0%	95,7%	94,0%	88,7%	90,0%
South to north	3,2%	3,0%	4,3%	6,0%	11,3%	10,0%

Source: calculations CREG based on data Elia

Table 5-7 Percentage of hours with loop flows in a certain direction

132. Phase-shifting transformers (PSTs) are installed on the Belgian borders to control the flow of active power on cross-border (and internal) network elements. Their settings (*"taps"*) can be adjusted to *"push back"* loop flows to a certain extent. The extent to which this can be done is determined by the amount of taps that can be used in the capacity calculation process. This amount is agreed by all the TSOs in the Core DA FBMC Project, and has increased compared to the ranges that were common practice in the CWE FBMC. Hence, individual TSOs have more liberty to control the level of loop flows that enter and exit their networks.

133. Figure 5-19 shows the impact of changing the PST taps on the observed loop flows. The horizontal axis shows the loop flows calculated before optimizing the PST taps, while the vertical axis shows the loop flows after this optimization. The diagonal line is set at 45°, indicating that values below it (at least in the upper right quadrant) represent hours where the level of loop flows before PST optimization exceeded the level of loop flows after the optimization. This shows that the PSTs have effectively pushed back the loop flows to a lower (absolute) level. During 90,6 % of all hours, absolute loop flows were reduced by setting the PST taps, on average with 273 MW.[36,37]

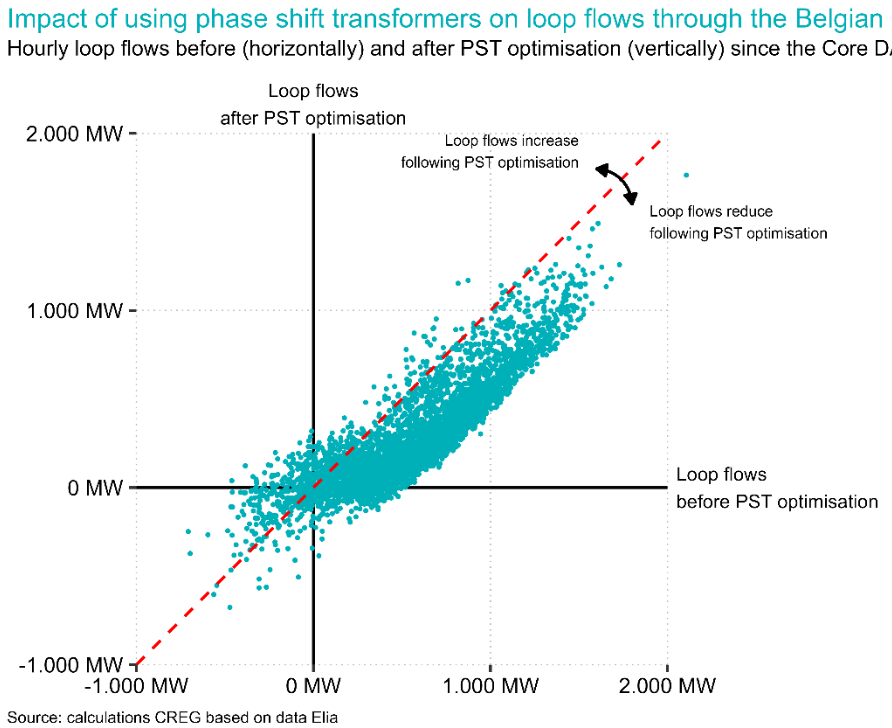


Figure 5-19 Impact of using phase shift transformers on loop flows through the Belgian network

[36] Calculations are performed only on data between 9 June and 31 December 2022, as loop flows before PST optimisation are not available prior to the Core DA FBMC go-live.

[37] Interestingly, during 9,5% of the hours in the observed period, the direction of the loop flows changed following the PST optimisation (i.e. from north>south to south>north, or vice versa). This is graphically shown in the top left or bottom right quadrant in the figure.

5.5. CONGESTION INCOME

134. When the transmission network is not able to accommodate all requests for cross-zonal capacity in the implicit day-ahead market coupling (due to internal or cross-zonal congestion), price differences can be observed between two bidding zones and congestion income is generated. This congestion income equals the commercial flow (from the relevant timeframe, in this case the day-ahead) multiplied by the price spread.[38]

135. Figure 5-20 shows, for Belgium, the net congestion income generated in the Belgian bidding zone, resulting from the capacity calculation and allocation in the flow-based market coupling (CWE or Core, depending on the period under consideration).

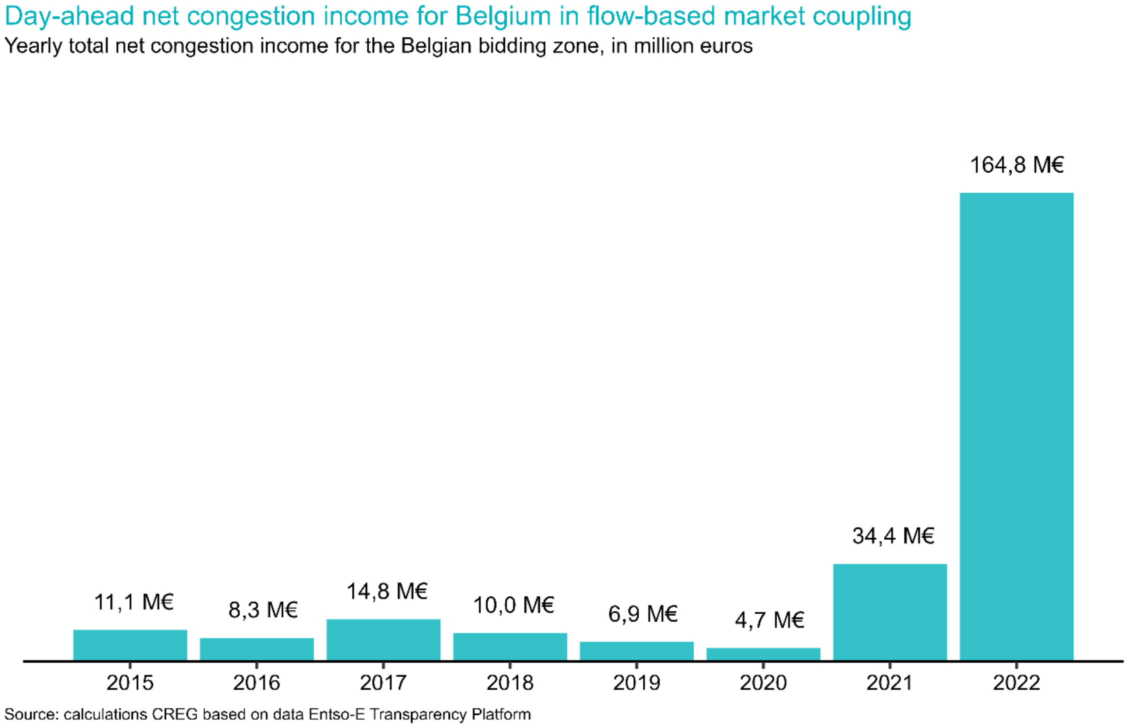


Figure 5-20 Day-ahead net congestion income for Belgium in flow-based market coupling

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

136. Net congestion income can be obtained after remunerating long-term transmission rights holders (either FTRs or PTRs, see also section 4.2. Figure 5-21 shows the comparison, per Core bidding zone, of the gross congestion income (in blue) and the net congestion income (in orange). Typically, countries with higher allocated long-term transmission rights, such as Austria, have to remunerate the rights holders more, leading to lower, or even negative, net congestion income. In Belgium, between 9 June and 31 December 2022, 88,8 M€ of the total gross congestion income (201,0 M€) was issued to long-term rights holders, leading to a net congestion income of 112,2 M€.

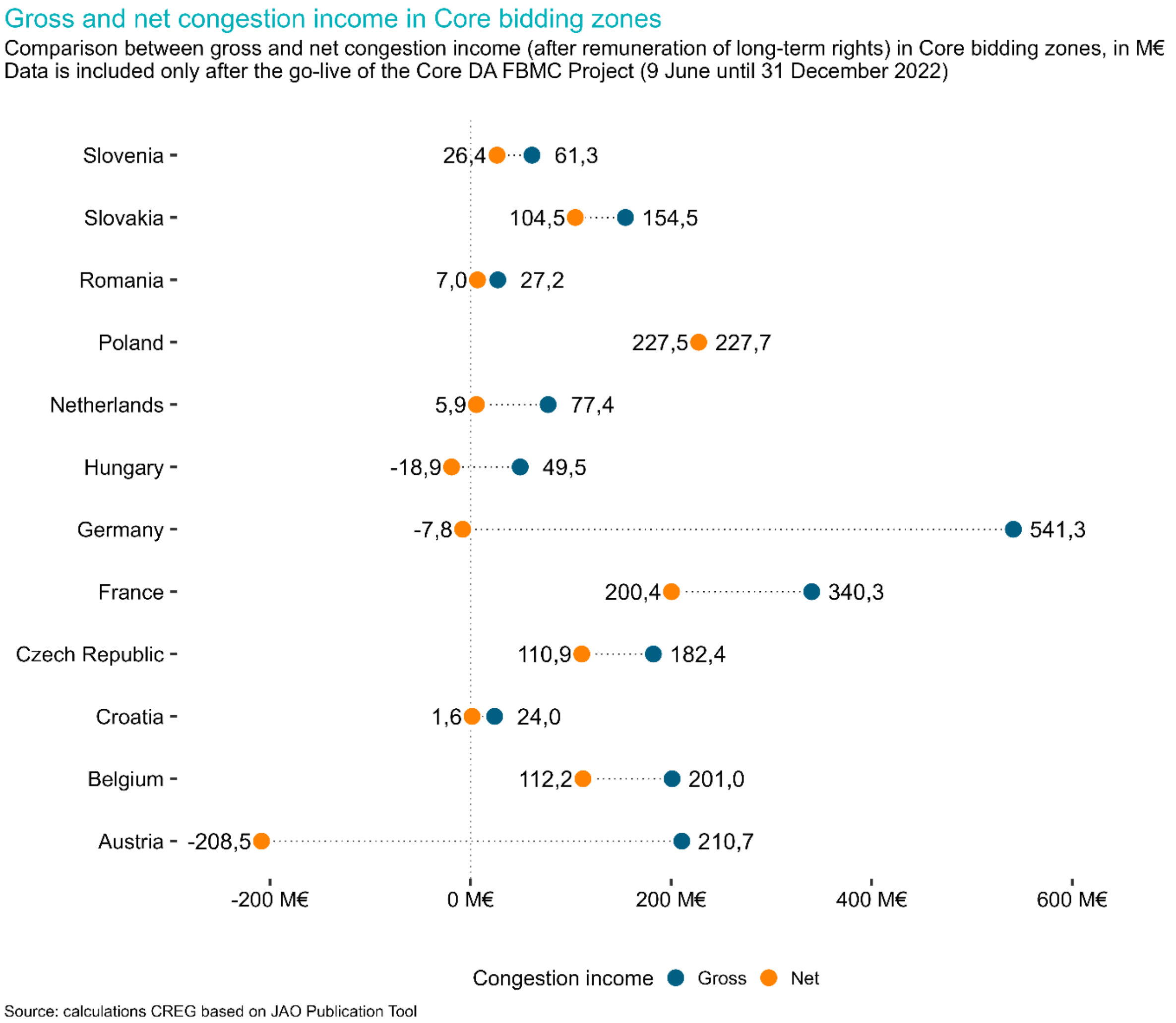


Figure 5-21 Gross and net congestion income in Core bidding zones

137. The figure above clearly shows that, overall, some bidding zones have negative net congestion income. This means that, structurally, their remunerations of long-term transmission right holders exceed the income from day-ahead market coupling. In order to avoid negative net income, surplus congestion income (where the day-ahead gross income exceeds the remunerations) is shared through a socialization mechanism.

6. INTRADAY MARKETS

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

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

6.1. EXCHANGED VOLUMES

140. The traded volumes in the cross-border continuous intraday market in Belgium, operated by Nord Pool and EPEX SPOT (coupled within the SIDC / XBID) increased significantly in 2022 to 4,4 TWh, compared to 2,9 TWh in 2021. This underlines the growing importance of the intraday market for market participants to adjust their positions closer to real time. The size of the coupled intraday market remains, however, significantly smaller than the day-ahead market (22,1 TWh in 2022).

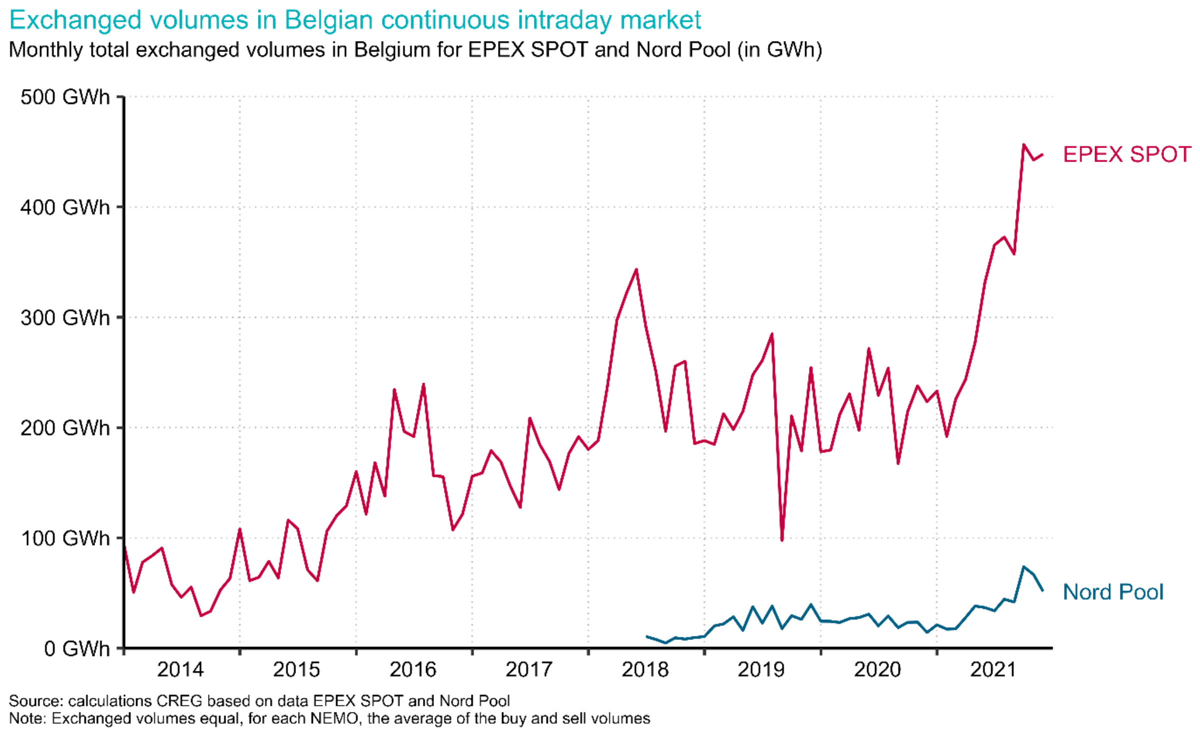


Figure 6-1 Exchanged volumes in Belgian continuous intraday market

141. As in the day-ahead market, the market shares of the incumbent EPEX SPOT remains high since the go-live of the multi-NEMO arrangements in the CWE region: 89,3% in 2022 which is basically equal to the share of 2021. Both NEMOs increased their volumes to a similar extent.

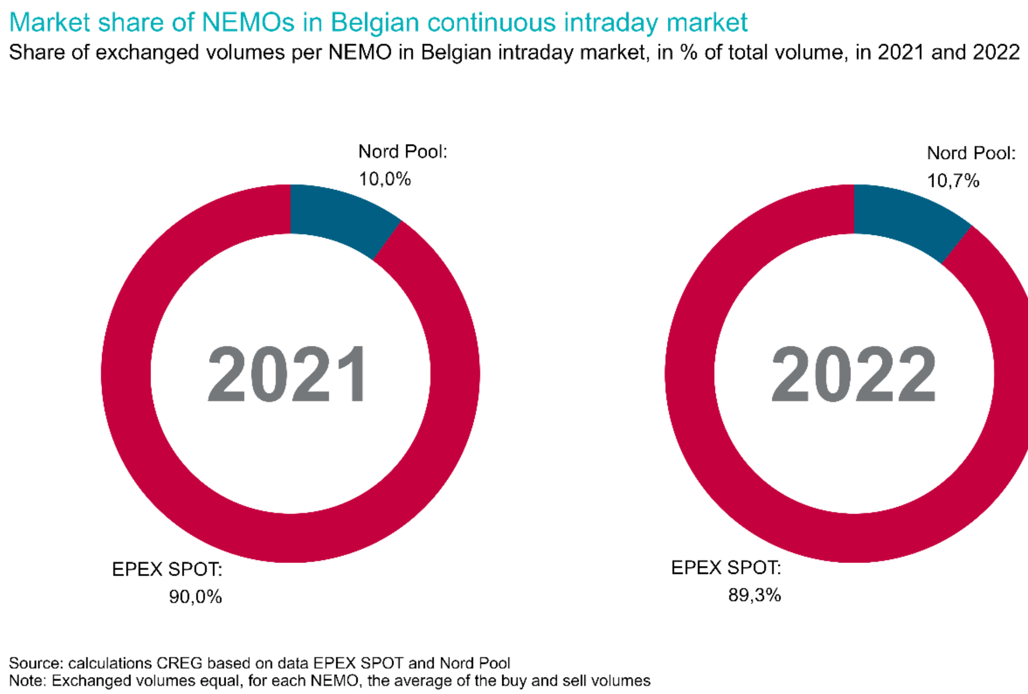


Figure 6-2 Market share of NEMOs in Belgian continuous intraday market

142. One of the reasons why market shares don't evolve in a more balanced manner, as is the case in the day-ahead market, is the importance of trading closer to real time, when the order books are not shared between both NEMOs. This is understood to be a barrier to participate with Nord Pool, and is being addressed in the current revision of the Electricity Market Design, proposed by the European Commission.

6.2. REFERENCE PRICES

143. Just as the day-ahead prices, the average intraday reference prices have increased significantly in 2022 (and 2021) compared to the previous years, despite a strong – yet temporary – decrease in 2020. The annual average prices in the intraday timeframe are closely aligned to those in the day-ahead market, as shown in Table 6-1

(in €/MWh)	2015	2016	2017	2018	2019	2020	2021	2022
Day-ahead	44,7	36,6	44,6	55,3	39,3	31,9	104,1	244,5
Intraday	44,0	37,9	45,7	56,3	40,2	31,2	103,9	247,1

Source: calculations CREG based on data EPEX SPOT

Table 6-1 Reference prices in the intraday timeframe versus day-ahead prices

144. While the yearly average prices, shown in Table 6-1, rarely deviate significantly from each other, the differential between the two metrics is much larger when considered with an hourly granularity. Between 2015 and 2020, the hourly differences between intraday and day-ahead prices were between -20 and 20 €/MWh in around 80% of all the hours of the year. This started changing in 2020 but more abruptly in 2021. In 2022, price differentials in the same range have been observed in only about 35% of all hours. Figure 6-3 shows the yearly histograms with the observations insofar as they fall within the -200 to 200 €/MWh range. The highest price differential between these timeframes, not pictured in the figure, was 1.571,5 €/MWh on 20 July 2022, when the intraday reference price temporarily reached a peak of 1.891,7 €/MWh.

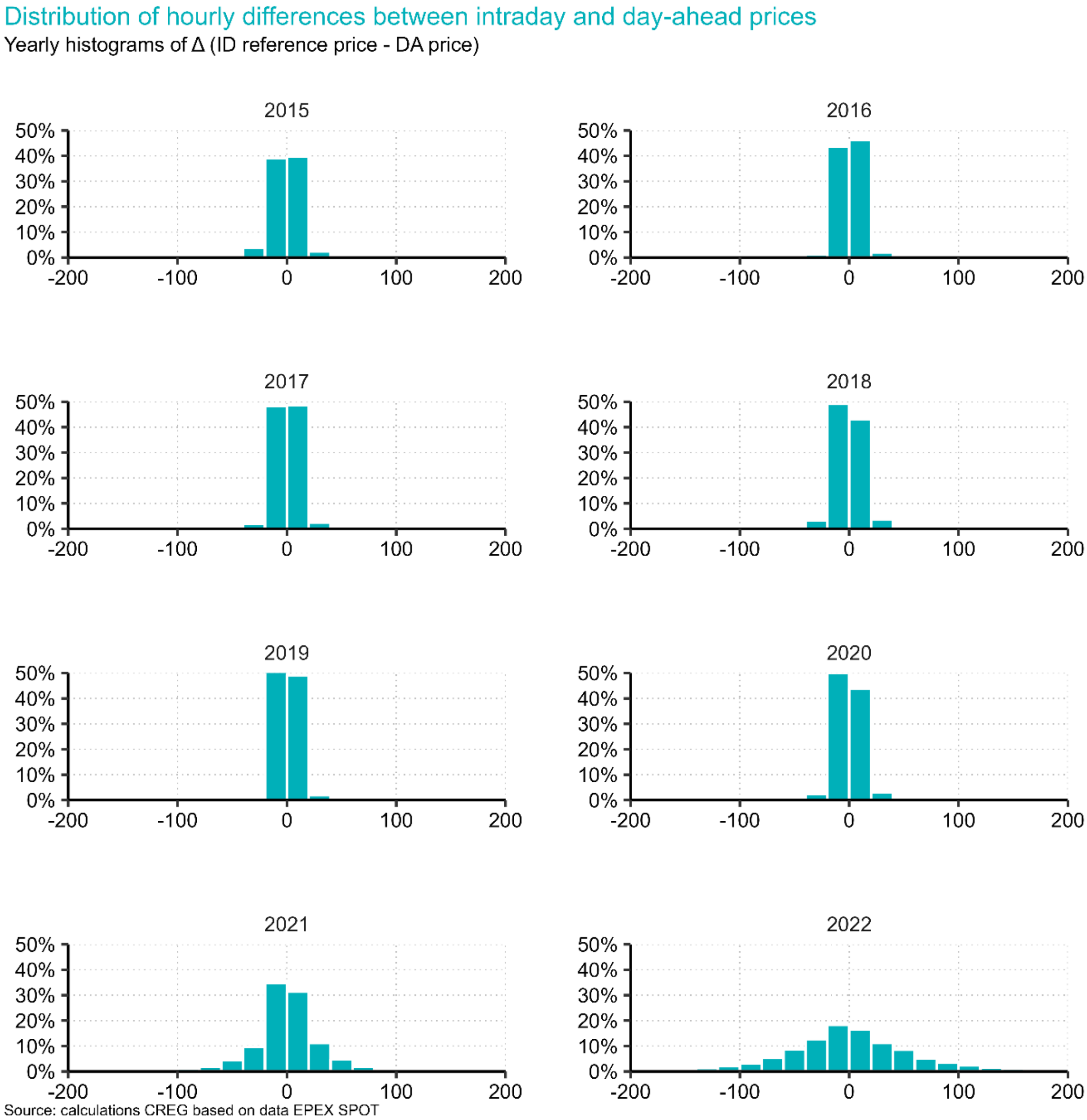


Figure 6-3 Distribution of hourly differences between intraday and day-ahead prices

145. The minimum value for the intraday reference price has gone below -200 €/MWh for the first time in 2022. As in the day-ahead timeframe, negative (reference) prices occur frequently as well. In 2022, these negative prices have been seen in 179 hours, which is a decrease compared to 2020 (304 hours) and 2021 (293 hours). The highest observed reference price in the intraday markets reached 1.819,7 €/MWh.

(in €/MWh)	2015	2016	2017	2018	2019	2020	2021	2022
Minimum	-9,3	-90,0	-44,1	-51,0	-150,0	-127,2	-184,4	-230,8
Maximum	420,0	572,9	426,6	590,0	276,5	612,2	604,2	1891,7

Source: calculations CREG based on data EPEX SPOT

Table 6-2 Yearly minimum and maximum intraday reference prices

6.3. CAPACITY CALCULATION

146. In the intraday timeframe, Elia and other European TSOs make capacity available for cross-zonal exchanges. In 2022, capacity calculation was performed in the framework of the CWE region, meaning that there is coordination between Elia and the TSOs of the Dutch, French, German and Austrian bidding zones. Despite the go-live of the DA FBMC Project in June, the coordination process (in particular the increases and decreases of the ATC values) are still coordinated only on the former CWE level – a coordinated intraday capacity calculation process on all Core borders is foreseen to go live in the summer of 2023.

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

148. Relatively high average capacity values appear in the time series: for example during 2018 from Belgium to France, or in the first half of 2019 from the Netherlands to Belgium. These could be explained by the fact that often these capacities are against the market direction (against the day-ahead price differential): used capacity in one direction (in the day-ahead timeframe) is then netted in the other direction for the intraday timeframe. This seems to be particularly the case for the high average export ATCs to France in 2022.

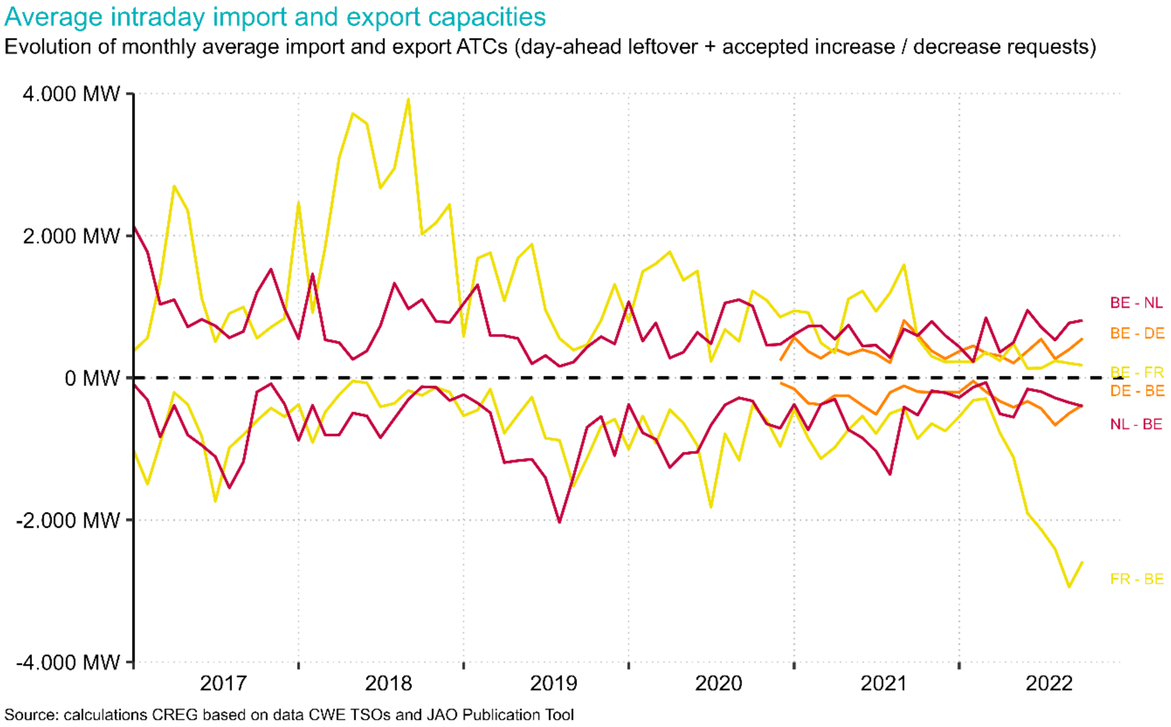


Figure 6-4 Average intraday import and export capacities

149. Despite the relatively high average intraday capacities shown above, the capacity calculation process (i.e. the initial ATC extraction, followed by the increase/decrease process) often results in zero ATC values. This implies that no capacity is available on a certain border for intraday cross-zonal exchanges. Figure 6-5 shows the share of hours in a certain direction (import or export) where no capacity is available on any of the borders with the Netherlands, France and Germany. In 2022, no import capacity was available in 16,3% of all hours, while no exchanges were possible in the export direction during 20,8% of the hours. Especially in the export direction, the historical numbers show an increasing trend, indicating that more and more often, no capacity is available for exporting energy in the intraday timeframe.

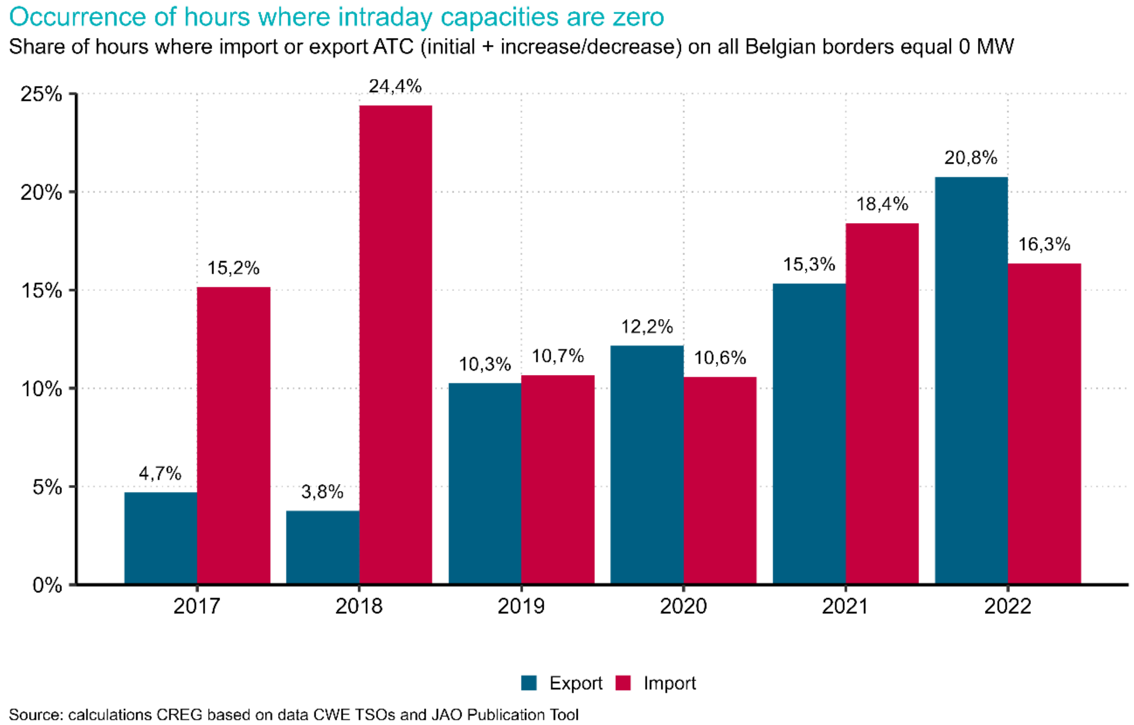


Figure 6-5 Occurrence of hours where intraday capacities are zero

150. As explained in paragraph 147, TSOs have the possibility to reassess the capacities which are extracted from the day-ahead domain (the initial ATC values). This reassessment leads to increase or decrease requests. The occurrence of such accepted requests is shown (in% of observed hours per year) in Table 6-3. These summary statistics show that, since 2017, the number of accepted increase request on the norther and southern border have decreased steadily, with an improvement on the southern border in 2022. It is also worth noting that decrease requests are only applied on the ALEGrO interconnector (the BE-DE and DE-BE border).

	INCREASE						DECREASE					
	BE-NL	BE-FR	BE-DE	NL-BE	FR-BE	DE-BE	BE-NL	BE-FR	BE-DE	NL-BE	FR-BE	DE-BE
2017	20,1%	39,8%		15,5%	20,2%		0,0%	0,0%		0,0%	0,0%	
2018	16,7%	17,9%		14,6%	12,9%		0,0%	0,0%		0,0%	0,0%	
2019	6,4%	8,5%		5,4%	11,7%		0,0%	0,0%		0,0%	0,0%	
2020	4,2%	8,9%		12,4%	17,4%		0,0%	0,0%		0,0%	0,0%	
2021	7,7%	8,6%	22,2%	4,7%	11,4%	18,6%	0,0%	0,0%	7,5%	0,0%	0,0%	3,1%
2022	3,8%	11,4%	9,9%	8,2%	18,3%	16,4%	0,0%	0,0%	0,6%	0,0%	0,0%	0,0%

Source: calculations CREG based on data CWE TSOs and JAO Publication Tool

Table 6-3 Yearly share of hours with accepted increase / decrease requests per border

151. In addition, Table 6-4 shows – for hours where accepted increase/decrease requests are found – the average volumes. These are, on most borders, between 200 and 300 MW, except when they are downward (i.e. decrease requests) on the ALEGrO interconnector.

	INCREASE						DECREASE					
	BE-NL	BE-FR	BE-DE	NL-BE	FR-BE	DE-BE	BE-NL	BE-FR	BE-DE	NL-BE	FR-BE	DE-BE
2017	217	216		221	216							
2018	217	230		211	225							
2019	249	267		253	256							
2020	218	257		266	256							
2021	244	251	232	252	249	232			-516			-364
2022	252	244	211	242	291	213			-417			-207

Source: calculations CREG based on data CWE TSOs and JAO Publication Tool

Table 6-4 Yearly average volume of the accepted increase / decrease requests per border

7. BALANCING MARKETS

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

7.1. BALANCING CAPACITY

7.1.1. FCR capacity

153. In 2022, the average price for procuring FCR capacity increased to 42,2 euro/MW/h. This price is around 36% higher than the average cross-border marginal price formed on the FCR Cooperation. The highest average price was nevertheless reached in Denmark, equal to 174,5 euro/MW/h.

FCR capacity	2015	2016	2017	2018	2019	2020	2021	2022
Need (MW)	83	68	68	81	81	78	87	86
Average cost (€/MW/h)	30,5	18,3	17,0	14,7	9,2	9,0 (i) 16,6 (ii)	31,7	42,2

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

Table 7-1 Capacity needs and procurement costs for FCR capacity in the LFC Area of Elia

7.1.2. aFRR capacity

154. In 2022, the volume of procured aFRR balancing capacity has been decreased from 145 MW to 117 MW. This reduction in aFRR capacity was justified because of the very high prices observed in the period before the change on 4/5/2022. The reduction did not endanger system security since the LFC Block of Elia was overperforming in terms of Frequency Restoration Control Error (FRCE) quality. The reduction resulted in an average price drop of around 13% for procuring the aFRR balancing capacity through the "all-CCTU" product, which represents the bulk of the procured aFRR capacities. Although prices increased in the "per-CCTU" product, given the lower procured aFRR capacity using this product, one can conclude that the overall reduction in procured aFRR capacity, as requested by the CREG, had a cost-saving effect for consumers.

aFRR capacity	2015	2016	2017	2018	2019	2020	2021	2022
Need (MW)	140	140	142	139	145	145	145	126 (iiia) 18 (iiib) 108 (iva) 18 (ivb)
Average cost (€/MW/h)	23,5	27,3	28,0	35,5	19,9	16,7 (i) 34,5 (ii)	95,3	482,6 (iiia) 45,9 (iiib) 417,8 (iva) 102,6 (ivb)

(i) Average aFRR capacity price before the introduction of daily procurement
(ii) Average aFRR capacity price after the introduction of daily procurement
(iii) Before 4/5/2022
(iv) From 4/5/2022 onward
(a) All-CCTU auction, upward and downward capacity combined
(b) Per-CCTU auction, upward and downward capacity combined
Source: calculations CREG based on data Elia

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

7.1.3. mFRR capacity

155. The price for procuring mFRR balancing capacity remained the cheapest of all the frequency restoration services. Consequently, the bulk of the required reserves are contracted in the form of mFRR. In 2022, the mFRR capacity to be procured increased because of a decrease in aFRR capacity to be procured.

mFRR capacity	2015	2016	2017	2018	2019	2020	2021	2022
Need (MW)	661	770	780	830	844	844 (i) 840 (ii)	857 643(*)	(a) 628 (b) 2,79
Average cost (€/MW/h)	3,2	3,6	3,4	9,9	6,6	4,9 (i) 6,0 (ii)	(a) 6,6 (b) 4,7	(a) 13,54 (b) 12,12

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

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

156. The Figure 7-1 below shows the evolution of the average price per mFRR auction (CCTU[39]) for 2021 and 2022, zoomed in on the average prices that remained below 100€/MW/h. In 2022, 32 CCTU had an average price of more than 100€/MW/h. The first CCTU for which the average price was higher than 100€/MW/h (384 €/MW/h to be exact) occurred on 29 June 2022. The CCTU with the highest average price of 486 €/MW/h occurred on December 7, 2022.

157. The average price per 1 MW of mFRR capacity clearly increased: in 2022 almost three times as many auctions of mFRR capacity as in 2021 were closed with an average price of more than 10€/MW/h (1140 auctions in 2022 versus 415 in 2021).

[39] CCTU = Capacity Contracting Time Unit

158. The energy crisis also appeared in the occurrence of second gate auctions for the procurement of mFRR capacity. In 2022 Elia organized a second gate auction for 98 contract periods (CCTU) versus 15 occasions in 2021.

159. Since June 2022 each month, except for November, knew at least one auction with zero non-awarded, offered volume, with an intense period of such occurrences at the end of August/beginning of September 2022. The average non-awarded, offered volume per mFRR capacity auction decreased significantly: while it was still above 400 MW/h in 2020, it decrease to 254 MW/h in 2021 and further down to 194 MW/h in 2022. The exact source of the decrease cannot be determined as the capacity bids do not include the technology on which the capacity is offered. However, it can be expected that the declared demand destruction is part of the cause. As demand facilities shut down because of energy prices that are too high to keep the operations running, also the demand response on the site is not available.

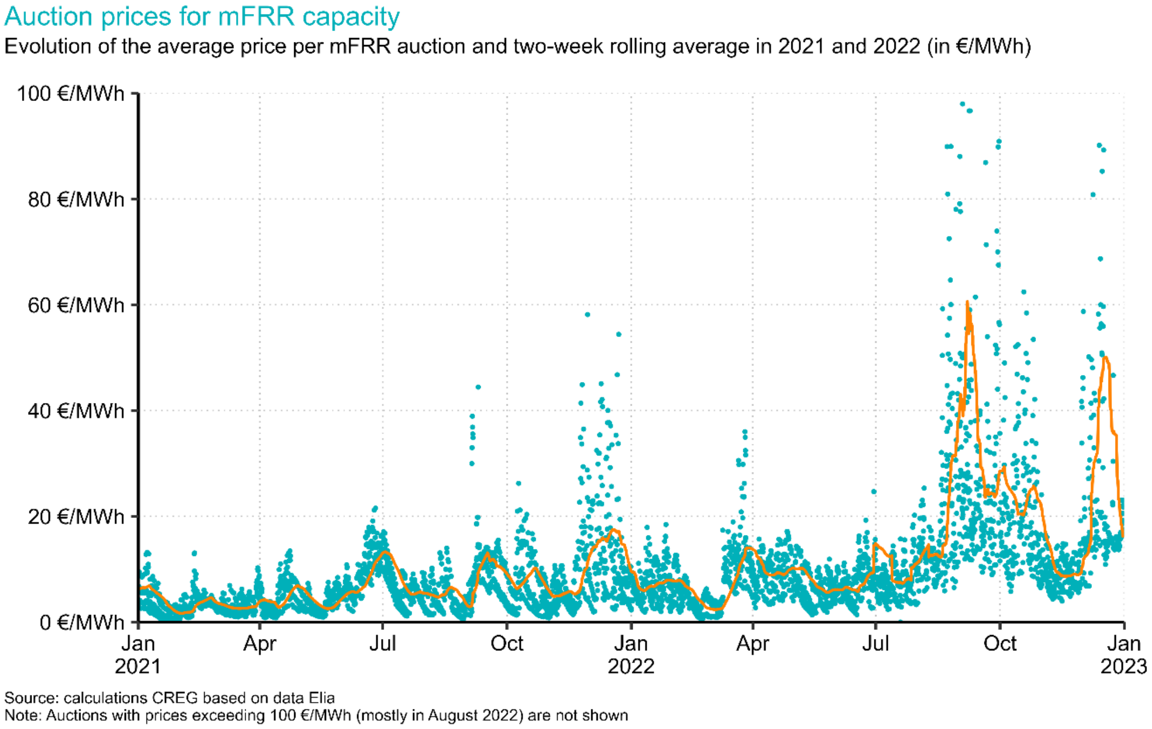


Figure 7-1 Auction prices for mFRR capacity

7.2. BALANCING ENERGY

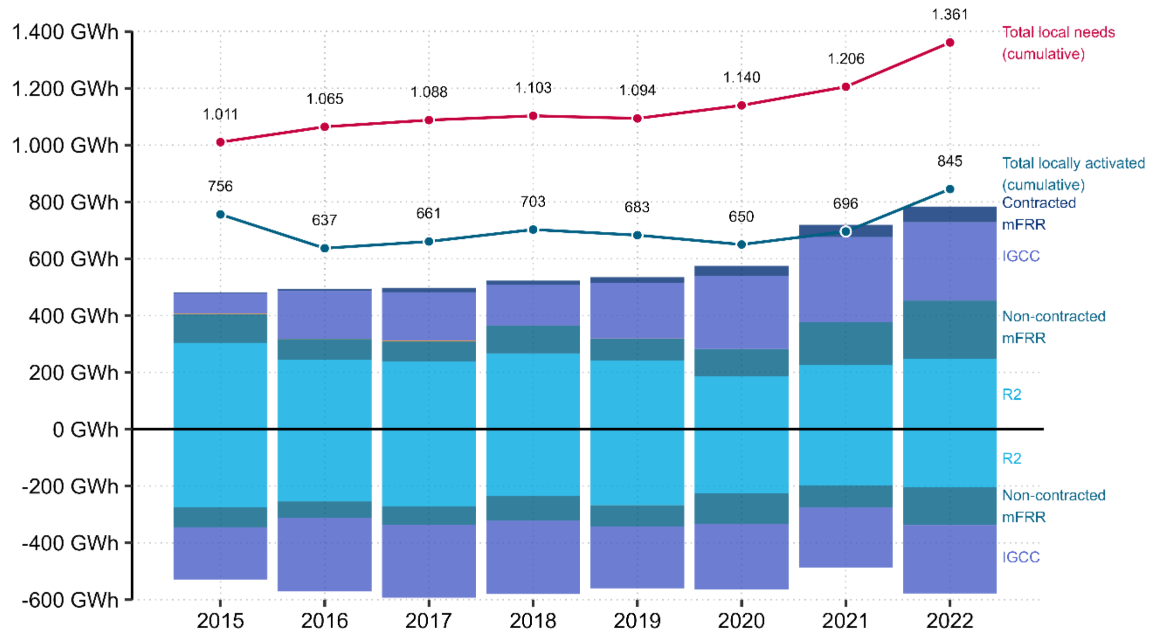
160. If BRPs as an aggregate fail to be in balance, a system imbalance is observed by Elia. The system imbalance must be compensated with FRR balancing energy within 15 minutes. In order to achieve this objective, multiple resources are activated.

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

162. The use of balancing resources to compensate system imbalances attained 1,36 TWh in 2022. Compared with an estimated Belgian consumption of 81,7 TWh in 2022, compensating the system imbalance accounts for 1,7% of the energy consumed (compared to 1,4% in 2021). In 2022, 37,9% of the balancing needs are compensated by imbalance netting. This share has decreased slightly with respect to 2021 (42,3%). The use of imbalance netting and aFRR to compensate negative system imbalances has slightly decreased with respect to 2021 (-3,3%). The use of imbalance netting and aFRR to compensate positive system imbalances has increased year over year in 2022 (+8,2%). The use of positive mFRR increased with 34,1% year over year in 2022. The total use of mFRR is volatile: the year-over-year change was +44,5% in 2022 and +14,2% in 2021. Reserve sharing was less used in 2022: no activation took place in the positive direction, and 678 MWh in the negative direction (-50% compared to 2021).

Balancing energy activated by product type

Evolution of yearly total energy activated per balancing product type (in GWh)



Source: calculations CREG based on data Elia

Figure 7-2 Balancing energy activated by product type

163. mFRR energy was activated during 18 % of the quarter-hours in 2022: the use of mFRR appears to be increasing during the years as mFRR was only activated up to a maximum of 10% of the quarter-hour per year in the years before 2021. Such increase in 2022 is mainly caused by the decrease in contracted aFRR. When activated, the average volume of mFRR per quarter-hour has been slightly increasing during the last years, up to 170 MW in 2022.

164. aFRR energy was activated during 89,4% (positive direction) and 87,9% (negative direction) of the time. This value represents a slight increase compared to 2021. In parallel, the average volume of activated aFRR has been increasing up to 28,3 MW (positive direction) and 24,8 MW (negative direction).

mFRR activations	2018	2019	2020	2021	2022
Number of days per year	308	296	324	336	355
Percentage of quarter-hours per year	9%	8%	9%	14%	18%
Average volume (MW)	145,6	146,3	161,5	159,2	170,2
Maximum volume (MW)	865,1	948,0	761,2	885,0	1276,9
aFRR activations					
Average volume positive (MW)	30,5	27,7	21,1	25,8	28,3
Maximum volume positive (MW)	144,0	145,1	165,0	197,3	208,3
Percentage of quarter-hours per year positive	86,5%	85,0%	88,7%	87,9%	89,4%
Average volume negative (MW)	26,8	30,4	25,7	22,4	24,8
Maximum volume negative (MW)	144,0	145,1	221,9	240,4	247,4
Percentage of quarter-hours per year negative	84,5%	86,9%	91,5%	87,9%	87,9%

Source: calculations CREG based on data Elia

Table 7-4 Activation of mFRR and aFRR reserves

7.3. IMBALANCES

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

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

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

Table 7-5 Flow of payments of imbalance prices

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

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

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

169. At the start of 2020 a new imbalance tariff methodology was introduced, changing the composition of the imbalance price compared to the previous tariff period. The determination of the alpha component was modified in order to provide quicker and larger incentives for the BRPs to take actions in favor of the system. The alpha component obtains a value larger than zero if the system imbalance for the quarter-hour is larger than 150 MW (in positive or negative direction). As of 14 February 2022 the calculation of the alpha component was adapted to ensure that the size of the incentive is in proportion to the expected BRP reaction. Experience had shown that as of a certain imbalance price, further increases of the alpha component did not lead to more BRP reaction and therefore the alpha component had a penalizing effect rather than an incentivizing effect. [40]

170. The total financial flow between Elia and the BRP for the settlement of the imbalances in 2022 was 654 million €: Elia had to pay the BRP 186 million € for positive imbalances while the BRP had to pay Elia 469 million € for having negative imbalances.

7.3.1. System imbalance

171. The distribution of the system imbalance follows a similar pattern each year, as shown in Figure 7-3, however a shift towards increasingly negative system imbalances is visible. In 2016-2017 42-44% of the quarter-hours measured a negative system imbalance. The number of quarter-hours with positive and quarter-hours with negative system imbalances was quasi the same within a year in 2018-2022 (48-52 %). In 2021 the share of quarter-hours with negative system imbalances, however, rose to 57%; this remained stable at 56% in 2022.

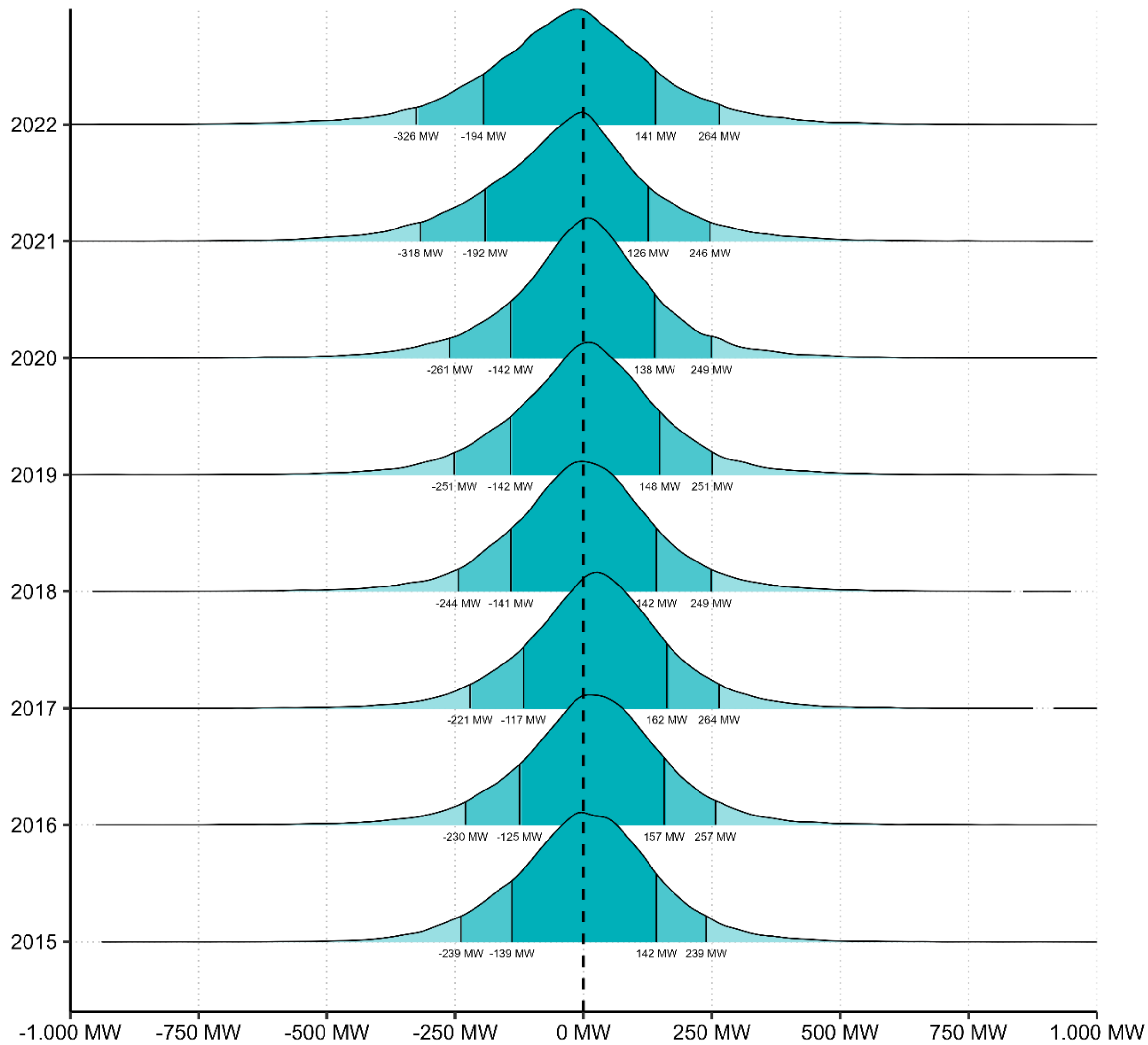
[40] The detailed description of the imbalance tariff is available on the web site of Elia: https://www.elia.be/en/customers/invoicing-and-tariffs/imbalance-invoice

172. The distribution is flatter in 2022 than in the previous years. The share of quarter-hours with a positive or negative system imbalance larger than 200 MW was 16-17% in the period 2015-2021; in 2021 this share rose to 22% and continued to rise in 2022 to 23%. The observations show less smaller imbalance (below 50 MW in either direction). The outlying values of the distribution are becoming more extreme: 1% of the negative system imbalances was larger than (-)537 MW and 1% of the positive system imbalances was larger than 438 MW.

173. During nearly all quarter-hours the system imbalance remains below 500 MW (in positive or negative direction). System imbalances above 1.000 MW occur rarely (see Table 7-6). Such large imbalances did occur more in 2019, with extremes of +1342 MW and -1.602 MW. In 2022 there was also a relatively high occurrence of large system imbalance with 21 quarter-hours showing a negative system imbalance of more than 1.000 MW (up to 1.330 MW).

Distribution of observed imbalances in the imbalance area of Elia

Evolution of yearly distributions of observed quarterly imbalances in the imbalance area of Elia (in MW)



Source: calculations CREG based on data Elia

Figure 7-3 Distribution of observed imbalances in the imbalance area of Elia

Number of quarter-hours	OFF-CHART OBSERVATIONS										
	[-1.700 - -1.600]	[-1.600 - -1.500]	[-1.500 - -1.400]	[-1.400 - -1.300]	[-1.300 - -1.200]	[-1.200 - -1.100]	[-1.100 - -1.000]	[1.000 - 1.100]	[1.100 - 1.200]	[1.200 - 1.300]	[1.300 - 1.400]
2015	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	1	0	0	0	0
2017	1	0	0	0	2	0	3	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0
2019	1	0	1	1	1	2	2	1	4	1	1
2020	0	0	0	0	0	0	1	1	0	0	0
2021	0	0	1	0	0	5	5	2	0	0	0
2022	0	0	0	2	3	5	11	4	2	0	0

Source: calculations CREG based on data Elia

Table 7-6 Distribution of observed imbalances in the imbalance area of Elia: off-chart observations

174. In 5% of the time (nearly 1900 quarter-hours in 2022), the system imbalance changes direction towards an (absolute) value of more than 150 MW from one quarter-hour to the next. This number shows a slight increase from previous years (ranging between 1400-1520 quarter-hours in 2018-2020 and about 1600 quarter-hours in 2021).

175. In 2022 during 65% of the quarter-hours the system imbalance remained lower than 150 MW (in positive or negative direction).

176. As in the previous years, more than 75% of the occurrences of system imbalance of more than 150 MW (in positive or negative direction) lasted one or two quarter-hours. In 2022, on 132 occasions a large system imbalance of 150 MW (in positive or negative direction) lasted more than 2 hours, of which 8 times longer than 5 hours. The longest period in 2022 lasted 30 consecutive quarter-hours: an negative system imbalance ranging between - 171MW and -873 MW occurred on March 17th from 07:30 until 14:45.

177. A look at the physical imbalances rather than the system imbalance also provides interesting insights. The physical imbalance (ACE or FRCE) shows the result of the actions of both the BRP (by reactive and self-balancing) and ELIA (by balancing energy activations) to compensate the system imbalance. In 2022 this physical imbalance ranged between -930 MW and 614 MW.

178. For 96% of the time in 2022, the physical imbalance remains between -150 MW and 150 MW. The majority of the occurrences of physical imbalances larger than 150 MW (in positive or negative direction) lasted one or two quarter-hours. During 10 events, the imbalances lasted 1 hour or more. The longest period in 2022 lasted 27 consecutive quarter-hours: an negative physical imbalance ranging between - 188MW and -426 MW occurred in the night between September 12th and 13th (from 21:00 until 03:30).

179. A comparison of the directions of the system imbalance and the physical imbalance per quarter-hour provide insight in the degree of simultaneous reaction by the BRP and by ELIA. During nearly one third of the quarter-hours since 2015 the system imbalance and physical imbalance have a different sign.

180. In general the observations show that a reduction in the system imbalance (therefore the BRP reaction) has most impact. In about half of those quarter-hours with positive system imbalance and negative physical imbalance (or vice versa), the system imbalance reduced while the net regulating volume did not increase. In 16 to 21% of the quarter-hours, the system imbalance reduced while the net regulating volume did increase, indicating a stronger reaction of both BRP and Elia. In about one third of the quarter-hours the increase in net regulating volume had more impact while the system imbalance did not decrease.

	(a) Different sign	(b)	SI decrease and NRV increase	SI decrease only	NRV increase only	No SI decrease or NRV increase
2015	33%		21%	51%	26%	2%
2016	32%		16%	50%	32%	2%
2017	31%		17%	50%	32%	2%
2018	33%		16%	51%	31%	2%
2019	32%		17%	51%	30%	2%
2020	30%		17%	51%	30%	2%
2021	29%		16%	54%	28%	2%
2022	31%		18%	53%	27%	2%

(a) Share of quarter-hours with different signs for the physical and system imbalance;
(b) For those quarter-hours in (a) the share of quarter-hours with a stronger reaction of the BRP (by a decrease in the system imbalance, "SI") and/or of Elia (by an increase in net regulating volume, "NRV")
Source: calculations CREG based on data Elia

Table 7-7 Direction of physical and system imbalances and reactions of BRPs and Elia

7.3.2. Imbalance prices

181. The imbalance prices reflect the same course as the day-ahead prices. The weekly average prices as shown in Figure 7-4 hide a strong volatility during the week but nonetheless clearly show the increase that started in 2021 and continued in 2022. The imbalance price in 2022 rose to an average of 234€/MWh: as shown in Table 7-8, this is an increase with 133% compared to 2021 and 5,5 times the average value during the period 2018-2020.

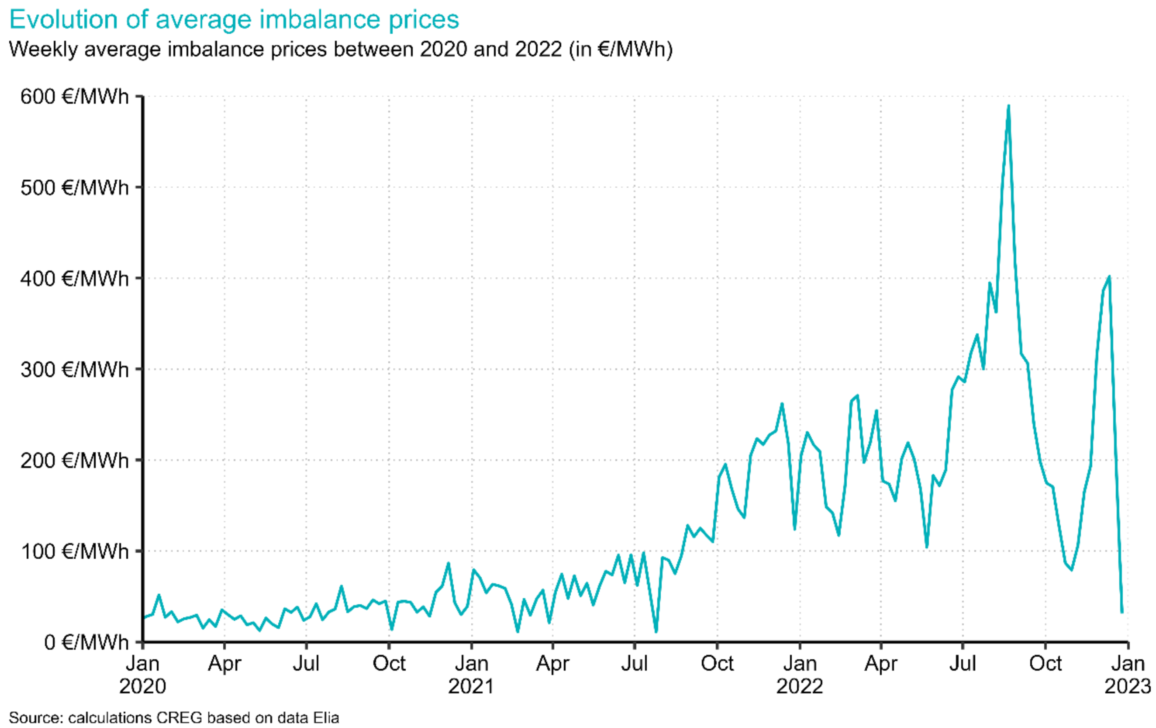


Figure 7-4 Evolution of average imbalance prices

(in €/ MWh)	Average imbalance price		
	Overall	If based on MIP	If based on MDP
2015	43,6	78,1	11,3
2016	35,0	62,8	10,6
2017	42,3	82,0	9,4
2018	53,8	98,5	12,1
2019	39,6	76,6	5,3
2020	33,8	70,3	-0,9
2021	100,3	171,7	5,7
2022	233,6	378,4	48,5

Source: calculations CREG based on data Elia

Table 7-8 Yearly average imbalance prices

182. The increase is especially visible for quarter-hours with negative imbalance in which the imbalance price is set by the "MIP" (i.e., the marginal incremental price or the highest price for activated upward aFRR energy or imbalance netting or activated upward mFRR energy) showing an average of 378€/MWh. This observation is in line with observations on system imbalances and offered balancing energy prices. In comparison to previous years, offered balancing energy prices are higher for the same volumes activated. In addition, more and particularly larger system imbalances push the marginal price for incremental activations up as energy further up the merit order of positive balancing energy is being activated.

183. For quarter-hours for which the imbalance price is based on the "MDP" (i.e., the marginal decremental price or the lowest price for activated downward aFRR energy or imbalance netting or activated downward mFRR energy), the average value in 2022 increased to 48,5€/MWh. The imbalance price was negative during only 67 quarter-hours, substantially less than the 3700 quarter-hours with negative imbalance price in 2021.

184. Since 2019 the imbalance price is reaching more extreme values, although the increase tempered in 2022. The imbalance price if based on the MIP reached a maximum of 2.000 €/MWh. The imbalance price if based on the MDP reached as low as -589,6 €/MWh in 2022.

(in €/MWh)	Maximum imbalance price	
	If based on MIP	If based on MDP
2015	822,9	-314,0
2016	1.510,3	-303,8
2017	652,8	-232,3
2018	901,5	-203,5
2019	2.163,5	-323,9
2020	2.297,4	-378,5
2021	3.199,9	-565,0
2022	2.000,0	-589,6

Source: calculations CREG based on data Elia

Table 7-9 Yearly maximum imbalance prices

185. The impact of the new determination of the alpha component starting from January 2020 is visible. Since then, the average alpha value is well above 1 €/MWh and the maximum alpha value of 200 €/MWh has been (nearly) reached in 2020, 2021 and 2022. The formula to determine the alpha value changed again as applicable of the middle of February 2022. The alpha determination changed in order to ensure that the alpha provided additional incentives to the BRP for balancing when the marginal prices remained below a threshold[41]. The new alpha determination, however, avoided that during quarter-hours with already sufficient incentive provided by high MIP or low MDP values, the alpha would only increase the financial impact of balancing without resulting in stronger incentives to balance the system. This change since February 2022 is visible in the following tables and figures.

186. The average alpha value in case the imbalance price is based on the MIP, dropped from 4,6 €/MWh in 2021 to 3,1 €/MWh in 2022 (from 16,1 to 10,2 €/MWh when only taking into account the quarter-hours during which the alpha is larger than zero).

(in €/MWh)	**Alpha component if imbalance price is based on MDP**		
	Average	Average (Alpha =/= 0) (i)	Maximum
2015	0,7	2,4	39,7
2016	0,9	2,7	35,4
2017	0,9	2,5	20,7
2018	0,8	2,7	28,5
2019	0,8	2,7	71,7
2020	3,4	12,9	199,8
2021	4,6	16,1	200,0
2022	3,1	10,2	198,3

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

Source: calculations CREG based on data Elia

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

187. Figure 7-5depicts the evolution of the system imbalance and the alpha component per quarter-hour from 2015 to 2022. The impact of the new design of the alpha component as of the 1st of January 2020 is clearly visible, as well as the change in the middle of February 2022. However, the new alpha design did not help to decrease the system imbalance compared to levels in the previous years. Consequently the CREG is analyzing whether the alpha can still be considered as an efficient price signal.

[41] When the MIP remained below 400 €/MWh or the MDP below 0 €/MWh.

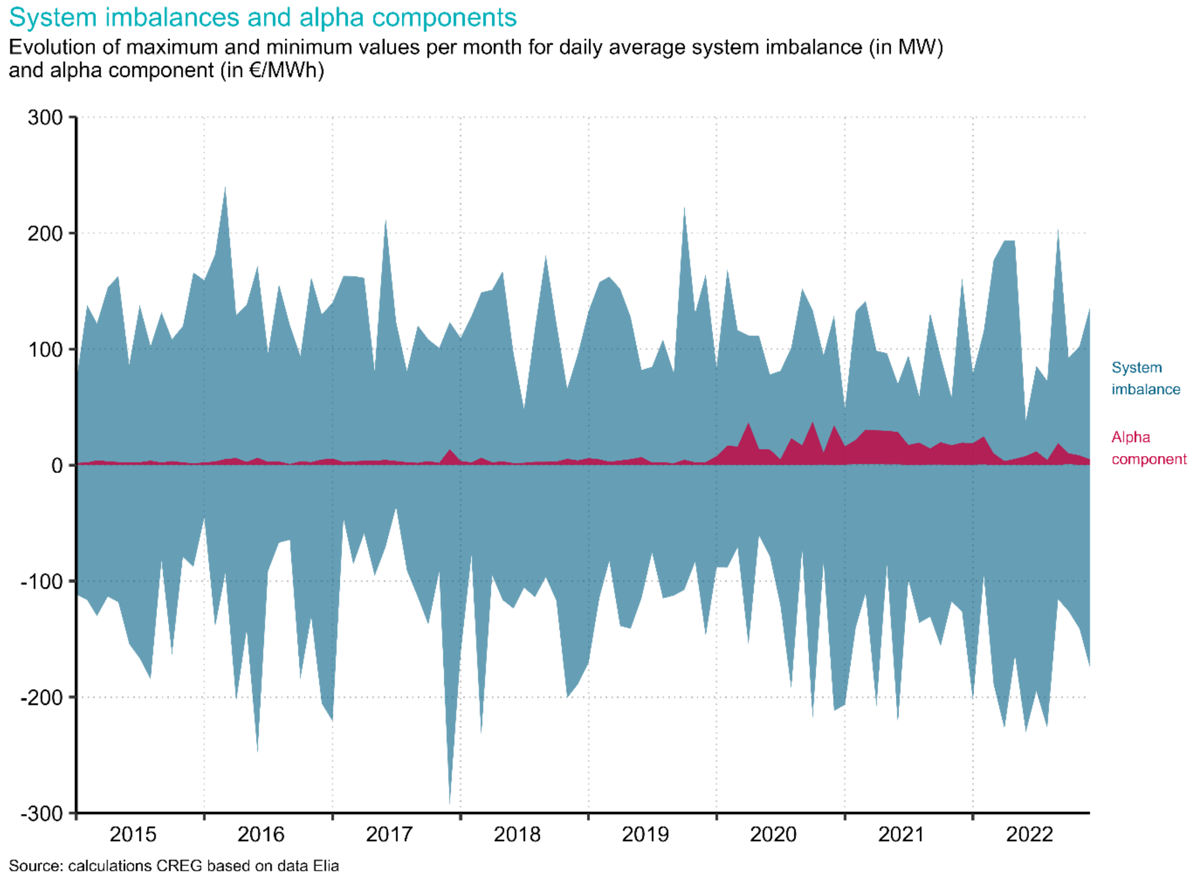


Figure 7-5 System imbalances and alpha components

8. NON-BALANCING ANCILLARY SERVICES

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

189. The ancillary services for reactive power management went through a substantial product change between 2015 and 2016. Since then, reservation costs for contracting the ancillary service are no longer foreseen except in exceptional cases (for instance investments or tariffs costs). In the last two years, the reservation cost for voltage services were substantially higher than before, largely due to the reimbursement of the “tariff for the power put at disposal” (in case the delivery of voltage services caused the provider to be confronted with this tariff).

190. Providers of voltage services are mainly remunerated for the activation of reactive power, meaning a change towards more reactive power production (or less absorption) in case of low voltage levels and a change towards more reactive power absorption (or less production) in case of high voltage levels. The activation costs have substantially increased during the last years, mainly due to an increased activated volume.

(k€)	2015	2016	2017	2018	2019	2020	2021	2022
Contracting	7.046	635	501	233	477	241	2.268	3.312
Activation	0	17.414	12.281	10.985	13.834	13.084	13.940	16.007
TOTAL	**7.046**	**18.049**	**12.781**	**11.218**	**14.311**	**13.325**	**16.208**	**19.319**

Source: calculations CREG based on data Elia

Table 8-1 Reactive power costs

191. Providers of black-start restoration services receive a remuneration for the daily availability of each black-start unit. The cost for the black-start ancillary services remains stable around 7 M€ during the last years.

(k€)	2015	2016	2017	2018	2019	2020	2021	2022
TOTAL	**6.262**	**7.192**	**7.274**	**7.279**	**7.323**	**7.041**	**6.854**	**6.991**

Source: calculations CREG based on data Elia

Table 8-2 Black start costs

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

9. CONCLUSION

In this study, the CREG analyzed the state and the functioning of the Belgian wholesale electricity markets. Historical evolutions are presented as a background to the recent trends, with a focus on 2022.

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

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

The Board of Directors of the CREG approved this study at its meeting of 1 June 2023.

For the Commission for Electricity and Gas Regulation

Andreas TIREZ	Laurent JACQUET	Koen LOCQUET
Director	Director	Acting Chairman of the Board of Directors

LIST OF FIGURES

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