The need for a **strategic reserve** for **winter 2021-22**

and winter outlook for 2022-23 and 2023-24

November 2020

Contents

Executive Summary

In accordance with the Belgian Electricity Act[1], Elia must submit a probabilistic analysis of Belgium's security of supply for the following winter by 15 November of each year. This analysis is an important element that the Federal Minister for Energy takes into account when deciding on the needed volumes for the strategic reserve. The decision for next winter (2021-22) must be taken by 15 January 2021 at the latest.

This report provides a probabilistic assessment of Belgium's security of supply for next winter (2021-22) under consulted hypotheses as required by the Electricity Act. In addition to the 'base case' scenario, Elia also performed a sensitivity analysis and evaluated the corresponding need for a strategic reserve. Elia makes its recommendation based on this sensitivity, which is unchanged in comparison with previous versions of this report. This approach was approved by the European Commission's DG Competition within the context of a State aid notification of the strategic reserve mechanism. As always, Elia also provides via this report, a preliminary outlook on the need for a strategic reserve for subsequent winters in 2022-23 and 2023-24 although the mechanism is currently only approved until winter 2021-22.

'Base case' scenario

Assumptions

The 'base case' scenario includes the following key assumptions:

- The economic projections of the Federal Planning Bureau from June 2020 were used to derive the total electricity consumption growth in Belgium. Such projections include a recovery of the consumption after the expected drop in 2020 following the Coronavirus disease (COVID-19) pandemic. The scenario results in a drop of -2.5% in electricity consumption for winter 2021-22 when compared to pre-COVID projections;
- In addition, in order to grasp the possible effect of the expected COVID-19 on the electricity consumption in the all the other modelled countries as well, the same reduction of -2.5% was applied for the winter 2021-22 on pre-COVID projections;
- Installed capacity forecasts for photovoltaic and onshore wind generation are based on the data from the regions, combined with a best estimate made by Elia and the FPS Economy about offshore wind generation are taken into account;
- With the expected go-live of the CORE flow-based (FB) market coupling mid-2021, commercial exchanges within the so-called CORE region will be allocated in the Day-ahead market using FB capacity allocation. In a first-of-its-kind improvement in adequacy assessments, Elia explicitly modelled these commercial exchanges

[1] Law of 29 April 1999 on the organization of the electricity market, Belgian Official Gazette, 11 May 1999

(in the whole CORE region) using its flow-based methodology. In addition, non-CORE exchanges are also taken into account via their NTC;

- A maximum global simultaneous import capacity of 6500 MW for Belgium for winter 2021-22 is applied. This limit applies to the sum of imports from CORE and the flow on the Nemo Link® interconnector; this limit will increase to 7500 MW for the two subsequent winters thanks to the addition of voltage control elements;
- The latest public information (REMIT) regarding the planned outages of nuclear units (as set out on the transparency websites of the nuclear units' owners dated 15 October 2020) for Belgium and France is used. In addition to any planned outages, the 'base case' scenario takes into stochastically modelled Forced Outage rate. This rate is derived from the Forced Outages as witnessed over the last 10 years. 'Exceptional' outages are not covered by this normal Forced Outage rate, but are addressed separately in the 'High Impact, Low Probability' (HiLo) scenario described later;
- It is important to note that the COVID-19 has significantly impacted the maintenance and refuelling of France's nuclear power plants in 2020: the maintenance had to be rescheduled inducing a higher planned unavailability than historically observed for the upcoming winters.

With respect to Belgian nuclear generation units, it is important to note that this study assumes:

- 1 GW is unavailable due to planned maintenance on Doel 3 from 28 Augustus to 05 October 2021;
- 1 GW is unavailable due to planned maintenance on Doel 4 from 23 October to 30 November 2021;
- 1 GW is unavailable due to planned maintenance on Tihange 3 from 21 February to 31 March 2022;
- Additionally, Forced Outages of the remaining nuclear units are statistically simulated at a rate of 3.7%, which is based on historical unplanned unavailability over the last 10 years, excluding long-lasting outages which are covered in the HiLo sensitivities.

Conclusion for the ‘base case’ scenario

The 'base case' scenario in this probabilistic assessment for next winter (2021-22) leads to a margin of 3300 MW, with an average LOLE of close to zero. Consequently, under the assumptions made in the 'base case' scenario, the analysis does not identify a need to contract a strategic reserve for winter 2021-22 in order to meet the legal criteria.

'High Impact, Low Probability' scenario

The availability of nuclear power plants has a significant impact on adequacy because they make up a significant share of the Belgian energy mix. The Forced Outage rates used in the calculations are based on historical unplanned unavailability over the last 10 years. Unexpected, long-lasting outages that occurred between 2010 and 2019 are not included in the Forced Outage rates in the 'base case' scenario because of their unusual nature. In this respect, the 'base case' scenario is overly optimistic with regards to assessing Belgian adequacy. A sensitivity analysis of nuclear availability, both in Belgium and France, provides a more robust approach for assessing the volume required for the strategic reserve. This approach has been approved by the European Commission's DG Competition within the context of its approval of the state aid notification of the strategic reserve mechanism.

Situation in Belgium

Given the significant impact on adequacy, it is important to analyse the 'High Impact, Low Probability' scenario. Previous studies comparing the modelled nuclear generation availability in the 'base case' with the actual availability observed, have shown that these 'High Impact, Low Probability' events could be captured by considering a sensitivity with an additional 1.5 GW of nuclear generation capacity out of service in Belgium. This capacity is considered to be out of service for the entire winter in addition to maintenance planning (REMIT) already considered in the 'base case' and the simulated Forced Outages.

Situation in France

Likewise, the unavailability of the French nuclear generation fleet has a major impact on the adequacy situation in Belgium, as seen for example in the winter of 2016-17 when multiple nuclear units were temporarily out of service at the request of the French nuclear safety authority. Therefore, in countinuity with last year's approach, in the 'High Impact, Low Probability' scenario, a capacity of 3.6 GW of nuclear generation must be considered out of service in France for the entire winter. This capacity is considered to be out of service in addition to the maintenance planning (REMIT) and the Forced Outages already considered in the 'base case' for France.

Conclusion for the ‘High Impact, Low probabilty’ scenario

When applying this sensitivity analysis, in order to capture 'High Impact, Low Probability' events, the analysis does not identify a need to contract a strategic reserve for winter 2021-22 in order to meet the legal criteria. The 'High Impact, Low Probability' scenario in the study leads to a margin of 0 MW with an average LOLE of close to 3h and a LOLE95 of 18h.

This conclusion reflects a slightly worse situation for Belgium than the preliminary outlook in the November 2019 strategic reserve volume report for winter 2021-22. This trend can be explained by the combination of several factors: notwithstanding the impact of COVID-19 on the nuclear availability in France, the assumption was made that the recovery after the COVID-19 would reduce demand across Europe.

However, this result is inextricably linked to the hypotheses considered for Belgium as well as for neighbouring countries. The risk of additional planned outages strengthens Elia's recommendation to make a decision based on the 'High Impact, Low Probability' scenario. Given the results at 0 MW, actual situations that go even beyond the hypotheses considered might lead to an adequacy issue for Belgium and a corresponding need for a Strategic Reserve.

Belgium remains dependent on imports for its electricity supply. Therefore, any change in the assumptions for neighbouring countries – related to their exporting capabilities or importing needs – will potentially have an impact on Belgium and on the associated strategic reserve volume. The maximum availability of domestic generation during the winter period is crucial for Belgium to maintain its adequacy. Therefore, Elia urges the generation units' owners to avoid any planned maintenance on their units during the winter period.

Recommendation to the Minister

To decide on the volume required for the strategic reserve for next winter (2021-22), Elia recommends taking into account the scenario incorporating low-probability events with a high impact on Belgian adequacy. This approach has been approved by the European Commission's DG Competition within the context of its approval of the state aid notification of the strategic reserve mechanism.

This scenario includes a reduction of nuclear unavailability for the entire winter of 1.5 GW in Belgium and 3.6 GW in France, in addition to the planned unavailability communicated by the generation units' owners in Belgium and France and the statistically determined Forced Outages.

This recommended scenario leads to a margin of 0 MW for Belgium for next winter (2021-22). Therefore, this scenario does not result in a need to constitute a strategic reserve for winter 2021-22.

Looking ahead

For **winter 2022-23** the **Belgian legal nuclear phase-out dates** have been taken into account. According to Article 4 of the nuclear phase-out legislation, Doel 3 is to be decommissioned by 1 October 2022 and Tihange 2 by 1 February 2023. To take into account for the decommissioning of the nuclear plant in Belgium, the corresponding HiLo sensitivity will be composed of two levels, 1.5 GW for the first part of winter when the overall installed capacity accounts to 5 GW and 1 GW as of the decommissioning of Tihange 2, bringing the installed nuclear capacity in Belgium to around 4GW. Following national policies, the net trend in terms of thermal generation capacity in Europe shows an overall decommissioning of around 16 GW. This trend can be mainly observed in neigbouring countries: the decommissioning of 8 GW of mostly coal, lignite and nuclear powerplants in Germany and the decommissioning of 4 GW of coal and nuclear power plants in Great Britain leads to a reduction in generation available for Belgian import. This is partly counterbalanced by an increased volume of renewable generation, market response, storage facilities and interconnection capacity available to the market (minRAM evolution) but still leads to an identified **need of 800 MW in winter 2022-23.**

For **winter 2023-24** the HiLo sensitivity for Belgium accounts for an additional nuclear unavailability of 1 GW for the entire winter. Under the current assumptions Elia has calculated that the **need** for the Belgian system under the 'High Impact, Low Probability' scenario is **100 MW.** This decrease compared to winter 2022-23 can be explained by several factors, the evolution of the minRAM trajectory towards 70% will increase the size of the flow-based domains, the **expected commissioning of new thermal generation** (e.g. Flamanville in France, new gas capacity in Great Britain…), the **addition of renewable capacity** and finally the **assumed increase of market response, storage** and **CHP in most of the countries** (of which more than 300 MW of new storage, 300 MW of new market response and 100 MW of new CHP in Belgium compared to today’s figures) **without any guarantee that those capacities will be made available by then**.

Additionally, and given Belgium's dependence on imports, the future exporting capabilities of neighbouring countries will continue to have a key impact on the expected adequacy situation and the need for domestic capacity in Belgium. It is important to bear in mind that the current strategic reserve mechanism has only been approved by the European Commission until winter 2021-2022. We therefore note that according to this study there is an identified need for capacity for the years 2022-2023 and 2023-2024, without that there is an (approved) mechanism for that period. We like to draw the attention of the public authorities on these observations and remain available to support them for any further reflection on the matter.

Elia would like to emphasise that the conclusions of this report are inextricably linked to the assumptions mentioned in the report. Elia cannot guarantee that these assumptions will actually materialize. In most cases, these are developments beyond the direct control or responsibility of the system operator.

Executive Summary (NL)

Zoals voorzien in de elektriciteitswet moet Elia tegen 15 november van elk jaar een probabilistische studie indienen van de Belgische bevoorradingszekerheid voor de volgende winter. Deze analyse is een belangrijk element dat in rekening wordt genomen door de Federale Minister van Energie bij het maken van een beslissing over de nood van het aanleggen van een strategische reserve. De deadline voor deze beslissing voor winter 2021-22 is 15 januari 2021.

Dit rapport bevat een probabilistische evaluatie van de Belgische bevoorradingszekerheid voor de komende winter (2021-22) onder geconsulteerde hypothesen zoals vereist in de elektriciteitswet. Naast een 'base case' scenario voerden we ook een sensitiviteitsanalyse uit. We baseerden onze aanbeveling op deze sensitiviteitsanalyse. Deze aanpak werd goedgekeurd door de DG competitie van de Europese Commisie in het kader van het staatssteunonderzoek van het strategische reserve mechanisme. Dit rapport biedt ook een vooruitblik op de nood van het aanleggen van een strategische reserve voor de winters 2022-23 en 2023-24.

'Base case' scenario

Hypothesen

Het 'base case' scenario bevat volgende hypothesen (enkel de voornaamste elementen voor België zijn hieronder opgesomd):

- Op basis van economische projecties van het Federaal Planbureau van Juni 2020 werd een prognose gemaakt wat betreft de totale jaarlijkse vraag naar elektriciteit in Belgie. Het scenario brengt het vermoedlijk herstel van de elektrische belasting na de initiele terugval als gevolg van de Coronavirus (COVID-19) pandemie in rekening. Voor winter 2021-22 is een vermindering van de electriciteitsconsumptie met -2.5% vergelijking met pre-COVID projecties voorzien;
- Ook in de andere gemodelleerde landen moet het mogelijke effect van de pandemie in rekening gebracht worden. Daartoe werd eenzelfde vermindering van -2.5% in totale electriciteitsconsumptie in vergelijking met pre-COVID projecties toegepast;
- Geïnstalleerde capaciteit voor fotovoltaïsche en onshore windproductie zijn gebaseerd op de laatste informatie van de regio's, gecombineerd met de beste inschatting gemaakt door Elia en de FOD Economie voor de offshore windproductie;
- Met de verwachte go-live van de CORE FB marktkoppeling 2021 zullen commerciële uitwisselingen in deze zogenaamde CORE regio in de day-ahead markt toegewezen worden volgens de flow-based methode. In een eerste-in-zijn-soort verbetering in analyses over bevoorradingszekerheid heeft Elia deze uitwisselingen (in de volledige CORE regio) expliciet gemodelleerd met behulp van zijn flow-based methodologie. Daarbovenop worden niet-CORE uitwisselingen in rekening gebracht met behulp van hun NTC;

- Een maximum simultane importcapaciteit van 6500 MW wordt toegepast voor België voor de winter 2020-21. Deze limiet bestaat uit zowel de import in de CORE regio als de flux op de Nemo Link® interconnector;
- Zowel voor België als voor Frankrijk werd de laatste publieke informatie (REMIT) over de toekomstige onderhoudsplanning van de nucleaire productie-eenheden in rekening gebracht, zoals aangeleverd op de transparantie websites van de eigenaars van de betrokken centrales (d.d. 15 oktober 2021). Bovenop de voorziene stops neemt de 'base case' ook de gemiddelde onvoorziene uitval (*forced outage*) in rekening. Deze wordt berekend op basis van de onvoorziene uitval zoals waargenomen in de laatste 10 jaar. Uitzonderlijke stops worden niet gedekt door de gemiddelde gedwongen uitvalratio maar worden apart behandeld in een 'hoge impact, lage waarschijnlijkheid sensitiviteit, die hieronder wordt beschreven:
- Het is belangrijk om te weten dat de COVID-19 pandemie een belangrijk effect heeft gehad op het onderhoud en bijvullen van splijtstof van Franse kernentrales in 2020. De nieuwe planning die als gevolg hiervan werd opgesteld leidt in de komende winters tot een hogere geplande onbeschikbaarheid dan gewoonlijk;

Voor de Belgische kernreactoren is het belangrijk te vermelden dat deze studie de volgende veronderstellingen in acht neemt:

- 1 GW is onbeschikbaar wegens een gepland onderhoud op Doel 3 van 28 Augustus tot 5 Oktober 2021;
- 1 GW is onbeschikbaar wegens een gepland onderhoud op Doel 4 van 23 Oktober tot 30 November 2021;
- 1 GW is onbeschikbaar wegens een gepland onderhoud op Tihange 3 van 21 Februari tot 31 Maart 2021;
- Bovenop de voorziene stops neemt de 'base case' ook de gemiddelde onvoorziene uitval (forced outage) in rekening. Deze wordt berekend op basis van de onvoorziene uitval zoals waargenomen in de laatste 10 jaar en is berekend op 3.7%. Uitzonderlijke stops worden niet gedekt door deze gemiddelde gedwongen uitvalratio maar worden apart behandeld in een 'Hoge impact, lage waarschijnlijkheid' sensitiviteit, die hieronder wordt beschreven;

Conclusie voor het ‘base case’ scenario

Het 'base case' scenario in deze probabilistische studie voor winter 2021-22 geeft aanleiding tot een marge van 3400 MW, met een gemiddelde LOLE dicht bij nul. Onder de hypothesen gemaakt in de 'base case' identificeert de analyse geen nood om een strategische reserve te procureren voor winter 2021-22 om de wettelijke bevoorradingszekerheidscriteria te respecteren.

'Grote impact, lage waarschijnlijkheid' scenario

De beschikbaarheid van Belgische nucleaire eenheden heeft, gezien de grote geïnstalleerde capaciteit, een zeer significante impact op de Belgische bevoorradingszekerheid. De gedwongen uitval ratio's gebruikt in deze studie zijn gebaseerd op de historisch ongeplande onbeschikbaarheden van de laatste tien jaar. Uitzonderlijk lange stops die voorkwamen op de nucleaire eenheden tussen 2010 en 2019 zijn niet opgenomen in deze ratio's in het 'base case' scenario gezien hun uitzonderlijke karakter. In dit aspect is het 'base case' scenario overoptimistisch om de Belgische bevoorradingszekerheid te evalueren. Een sensitiviteit op de nucleaire beschikbaarheid, zowel in België als in Frankrijk, is een meer robuuste manier om de volumenood aan strategische reserve te bepalen. Deze aanpak is goedgekeurd door de DG competitie van de Europese Commisie in het kader van het staatssteunonderzoek van het strategische reserve mechanisme.

Situatie in België

Een gedetailleerde vergelijking tussen de gemodelleerde beschikbaarheid in de 'base case' en de reële Belgische nucleaire beschikbaarheid over de laatste zeven winters toont aan dat dit soort 'grote impact, lage waarschijnlijkheid' situaties kunnen gevat worden in een sensitiviteit waarin een additionele 1,5 GW nucleaire productiecapaciteit voor de hele winter in België als buiten dienst wordt beschouwd. Deze capaciteit wordt buiten dienst beschouwd bovenop de reeds voorziene geplande onderhoudswerken (REMIT) uit de 'base case' en de gesimuleerde gedwongen uitval.

Situatie in Frankrijk

Daarenboven heeft ook de onbeschikbaarheid van het Franse nucleaire productiepark een belangrijke impact op de bevoorradingszekerheidssituatie in België, zoals werd geobserveerd in de winter van 2016-17 wanneer meerdere nucleaire eenheden in Frankrijk tijdelijk buiten dienst werden genomen op vraag van het Franse nucleaire veiligheidsagentschap. Daarom, in lijn met de aanpak van de vorige berekening voor strategische reserve, zal voor de sensitiviteit in Frankrijk 3.6 GW aan nucleaire capaciteit genomen worden. Deze capaciteit is verondersteld de hele winter buiten dienst te zijn bovenop de reeds geplande onderhoudswerken (REMIT) en de gesimuleerde gedwongen uitval reeds voorzien in de 'base case' voor Frankrijk.

Conclusie voor het 'Grote impact, lage waarschijnlijkheid' scenario

De sensitiviteitsanalyse, bedoeld om 'grote impact, lage waarschijnlijkheid' situaties in rekening te brengen, toont geen nood aan tot het aanleggen van een strategische reserve voor winter 2021-22 om aan de wettelijke bevoorradingszekerheidscriteria te voldoen. De 'grote impact, lage waarschijnlijkheid' sensitiviteit in deze studie leidt tot een marge van 0 MW met een gemiddelde LOLE van nabij de 3 uur en een LOLE95 van 18 uur.

Deze conclusie komt neer op een lichte verslechtering van de situatie voor België vergeleken met de vooruitblik voor winter 2021-22 van het volumerapport van November 2019. Deze trend verschijnt door een combinatie van verscheidene factoren: enerzijds leidt het herstel na de COVID-19 pandemie tot een verminderde vraag naar elektriciteit in Europa. Anderzijds wordt er in de toekomstige winters een verslechterde nucleaire beschikbaarheid in Frankrijk verwacht.

Dit resultaat is onafscheidbaar van de genomen hypothesen voor België en de buurlanden. Het risico op bijkomende geplande onbeschikbaarheden versterkt Elia's aanbeveling op een beslissing te maken op basis van het 'grote Impact, Lage Waarschijnlijkheid' scenario. Gezien de berekende marge 0 MW bedraagt kunnen situaties die verder gaan dan de beschouwde hypothesen aanleiding geven tot bevoorradingszekerheidsproblemen in België en bijgevolg aanleiding geven tot een nood aan Strategische Reserve.

Belgie blijft afhankelijk van de import van elektriciteit voor zijn bevoorradingszekerheid. Veranderingen in de hypothese voor buurlanden – gelinkt aan hun export- of importcapaciteiten - hebben dan ook mogelijk een grote impact op Belgie en het geassocieerde benodigde volume aan strategische reserve. Een zo groot mogelijke beschikbaarheid van Belgische productie-eenheden tijdens de winterperiode is dus cruciaal om de Belgische bevoorradingszekerheid te waarborgen. Daarom dringt Elia er bij de eigenaren van productie-eenheden ook op aan om geplande onderhouden tijdens de winterperiode te vermijden.

Aanbeveling aan de Minister

Bij het bepalen van een volumenood aan strategische reserve voor komende winter 2021-22 beveelt Elia aan een beslissing te nemen op basis van het scenario dat 'grote impact, lage waarschijnlijkheid' situaties in rekening neemt. Deze aanpak is goedgekeurd door de DG competitie van de Europese Commissie in het kader van het staatssteunonderzoek van het strategische reserve mechanisme.

Dit scenario bevat een reductie van 1,5 GW nucleaire productiecapaciteit in België en 3,6 GW in Frankrijk gedurende de hele winter. Deze onbeschikbaarheden komen bovenop reeds geplande onbeschikbaarheden zoals gecommuniceerd door de respectievelijke eigenaars in Belgie en Frankrijk en de statistisch bepaalde gedwongen uitval ratio's.

Elia's aanbevolen scenario leidt tot een marge van 0 MW voor België voor de volgende winter (2021-22). Daarom is er in dit scenario geen nood tot het procureren van een strategische reserve voor winter 2021-22.

Een vooruitblik

Voor **winter 2022-23** werd de **nucleare phase-out** in rekening gebracht. Volgens de wet op de nucleaire uitfasering (art. 4), is Doel 3 gepland om uit dienst genomen te worden op 1 oktober 2022 en Tihange 2 op 1 februari 2023. Om het uitfaseren van de kerncentrales in rekening te brengen wordt de bijhorende sensitiviteit in het 'Hoge Impact, Lage Waarschijnlijkheid' scenario aangepast. 1.5 GW wordt in rekening gebracht voor het eerste deel van de winter wanneer de geïnstalleerde nucleaire capaciteit 5 GW bedraagt. Vanaf de uitdienstname van Tihange 2 zal de totale geïnstalleerde capaciteit nog slechts 4 GW bedragen en wordt de bijhorende sensitiviteit teruggebracht worden tot 1 GW. Gezien de nationale politieken wat betreft thermische capaciteiten wordt in Europa een totale uitdienstname van om en bij de 16 GW verwacht voor deze winter. Deze trend toont zich sterk in onze buurlanden: Een uitdienstname van hoofdzakelijk steen- en bruinkoolcentrales in Duitsland voor een totale capaciteit van 8 GW samen met een vermindering van hoofdzakelijk steenkoolcentrales en nucleaire eenheden van 4 GW in het Verenigd Koninkrijk. Deze verminderingen in buitenlandse capaciteit leiden er ook toe dat er minder elektrische energie beschikbaar zal zijn voor invoer in Belgie. Deze effecten worden deels tegengewerkt door een groter volume aan hernieuwbare generatie, marktrespons, opslagcapaciteit en interconnectiecapaciteit opengesteld aan de internationale markt (evolutie van de minRAM) maar leiden desondanks tot **een nood aan strategische reserve voor de winter 2022-23 van 800 MW**.

Voor winter 2023-24 wordt in het 'grote impact, lage waarschijnlijkheid' scenario voor Belgie een bijkomende nucleaire onbeschikbaarheid van 1 GW in rekening gebracht. Bijgevolg tonen Elia's berekeningen aan dat voor winter 2023-24, onder de huidige hypothesen de **nood** op het Belgische elektrische energiesysteem voor het 'grote impact, lage waarschijnlijkheid' scenario **100 MW zal bedragen.** De vermindering van nood in vergelijking met winter 2022-23 kan verklaard worden door verscheidene factoren, de verdere evolutie van de minRam naar 70% zal de flow-based domeinen vergroten. Daarbovenop komt een **verwachte stijging van thermische capaciteit** (e.g. Flamanville in Frankrijk, nieuwe gescentrales in het Verenigd Koningkrijk, …), een **stijging in capaciteit van hernieuwbare generatie** en een **verdere verhoging van het beschikbare volume aan marktrespons**, **opslagcapaciteit en CHP** in de meeste landen (waarvan in Belgie meer dan 300 MW nieuwe opslagcapaciteit, een verhoging van het volume marktrespons met 300 MMW en 100 MW meer CHP in vergelijking met de situatie van vandaag) **zonder garantie dat deze capaciteiten tegen dan beschikbaar zullen zijn**.

Bovendien, en gezien de afhankelijkheid van België van invoer, zullen de toekomstige exportcapaciteiten van de buurlanden een belangrijke impact blijven hebben op de verwachte bevoorradingszekerheid en de behoefte aan binnenlandse capaciteit in België. Het is belangrijk te onthouden dat het huidige strategische reservemechanisme slechts tot de winter van 2021-2022 door de Europese Commissie is goedgekeurd. We stellen dan ook vast dat er volgens deze studie een geïdentificeerde behoefte is aan capaciteit voor de jaren 2022-2023 en 2023-2024, zonder dat er voor die periode een (goedgekeurd) mechanisme bestaat. Wij willen de aandacht van de overheid op deze constatering vestigen en blijven beschikbaar om hen te ondersteunen bij eventuele verdere reflecties over deze kwestie.

Elia wenst te benadrukken dat de conclusies van dit rapport onlosmakelijk verbonden zijn aan de hypothesen genomen in deze studie. Elia kan niet garanderen dat deze hypothesen werkelijkheid worden. In de meeste gevallen zijn deze ontwikkelingen buiten de directe controle of verantwoordelijkheid van de netbeheerder.

Executive Summary (FR)

Comme prévu dans la loi Électricité, Elia doit soumettre, le 15 novembre de chaque année, une analyse probabiliste sur l'adéquation de la Belgique pour l'hiver suivant. Cette analyse est un élément important à prendre en compte par le ministre fédéral de l'Énergie pour prendre une décision sur le volume de réserve stratégique nécessaire. L'échéance de cette décision pour l'hiver 2021-22 est fixée à la date du 15 janvier 2021.

Ce rapport fournit une évaluation probabiliste de la sécurité d'approvisionnement de la Belgique pour le prochain hiver (2021-22) comme requis par l'article 7bis de la loi Electricité en tenant compte des hypothèses consultées. Outre le scénario 'base case', nous avons aussi effectué une analyse de sensitivité et en évaluant le besoin de réserve stratégique correspondant. Cette approche a été approuvée par la Direction Générale de la concurrence de la Commission Européenne dans le contexte de l'examen des aides d'Etat pour le mécanisme de réserves stratégiques. Ce rapport donne également une première estimation sur le besoin en réserve stratégique pour les périodes hivernales suivantes : 2022-23 et 2023-24.

Scenario 'base case'

Hypothèses

Le scénario 'base case' comprend les hypothèses listées ci-dessous:

- Les projections économiques du Bureau Fédéral du Plan ont été utilisées comme base afin d'estimer la croissance de la consommation d'électricité en Belgique. Ces projections incluent une reprise de la consommation après la baisse prévue en 2020 suite à la pandémie de la maladie coronavirus (COVID-19). Ce scénario se traduit par une baisse de 2,5 % de la consommation d'électricité pour l'hiver 2021-22 par rapport aux projections antérieures à la COVID ;
- en outre, afin de saisir l'impact possible de la COVID-19 prévue sur la consommation d'électricité dans tous les autres pays modélisés, la même réduction de 2,5 % a été appliquée pour l'hiver 2021-22 par rapport aux projections pré-COVID ;
- les prévisions de capacité installée pour le photovoltaïque et l'éolien terrestre sont issues des dernières données disponibles auprès des autorités régionales, combinées aux meilleures estimations du SPF Economie et d'Elia pour l'éolien offshore;
- Avec la mise en service prévue du couplage de marché basé flow-based (FB) sur la zone CORE à la mi-2021, les échanges commerciaux au sein de la région dite CORE seront attribués sur le marché Day-ahead en utilisant l'allocation de capacité FB. Dans le cadre d'une amélioration inédite des évaluations de l'adéquation, Elia a explicitement modélisé ces échanges commerciaux en utilisant sa méthodologie flow-based. En outre, les échanges non CORE sont également pris en compte via leur NTC ;

— la prise en compte des dernières informations publiques (REMIT) concernant les plannings de maintenance des unités nucléaires (comme indiqué sur les sites Web de transparence des exploitants des unités nucléaires concernées (datant du 15 octobre 2019)). En plus de ces maintenances planifiées, les simulations du scénario 'base case' tiennent compte d'un taux d'indisponibilité fortuite statistiquement normal. Ce taux d'indisponibilité est calculé sur base des indisponibilités observées ces 10 dernières années. Les indisponibilités « exceptionnelles » ne sont pas couvertes par ce taux d'indisponibilité fortuite statistiquement normal, mais sont traitées séparément par l'ajout d'une sensitivité à grand impact mais faible probabilité ('High Impact, Low Probability' ou 'HiLo') ;
— il est important de noter que la COVID-19 a eu un impact significatif sur la maintenance et le réapprovisionement des centrales nucléaires françaises en 2020 : la maintenance a dû être reprogrammée, entraînant une indisponibilité planifiée plus importante que celle observée historiquement pour les hivers à venir.

En ce qui concerne les unités de production nucléaire belges, il est important de noter que :

— 1 GW sera indisponible en raison de la maintenance planifiée sur Doel 3 du 28 août au 5 octobre 2021;
— 1 GW sera indisponible en raison d'une maintenance planifiée sur Doel 4 du 23 octobre au 30 novembre 2021;
— 1 GW sera indisponible en raison d'une maintenance planifiée sur Tihange 3 du 21 février au 31 mars 2022;
— En outre, les arrêts forcés des autres unités nucléaires sont statistiquement simulés à un taux de 3,7%, qui est basé sur l'indisponibilité historique non planifiée au cours des 10 dernières années, à l'exclusion des arrêts de longue durée qui sont couverts par la sensibilité HiLo.

La Belgique reste dépendante des importations pour son approvisionnement en électricité. Par conséquent, toute modification des hypothèses concernant les pays voisins (en relation avec leur aptitude à exporter ou importer) présentera un impact potentiel sur la Belgique et sur le volume de la réserve stratégique associée.
La disponibilité maximale de la production domestique pendant la période hivernale est cruciale pour que la Belgique maintienne son adéquation. Elia exhorte donc les exploitants des unités de production concernées à éviter au maximum tout entretien prévu de leurs unités pendant la période hivernale.

Conclusion

Le scenario 'base case' de cette étude probabiliste pour l'hiver suivant (2021-22) indique une marge de 3300 MW, avec un LOLE moyen proche de zéro. En tenant compte des hypothèses du scénario 'base case', l'analyse n'identifie pas un besoin de contracter de la réserve stratégique pour l'hiver 2021-22 pour satisfaire les critères légaux.

'High impact, Low probability' Scenario

La disponibilité des unités de production nucléaires a un impact significatif sur l'adéquation de par le fait que celles-ci constituent un grande part du mix électrique Belge. Les taux d'indisponibilité fortuite utilisés dans les calculs sont basés sur les indisponibilités non planifiées historiques au cours des dix dernières années. Les indisponibilités exceptionnelles et de longue durée qui se sont produites entre 2012 et 2019 ne sont pas comprises dans ces taux d'indisponibilité fortuite dans le scénario 'base case', en raison de leur nature inhabituelle. Dès lors le scénario 'base case' apparait comme trop optimiste pour évaluer correctement l'adéquation en Belgique. Une sensitivité sur la disponibilité du nucléaire, tant en Belgique qu'en France, apparait donc constituer une approche plus robuste pour évaluer le besoin en volume de réserve stratégique. Cette approche a été approuvée par la Direction Générale de la concurrence de la Commission Européenne dans le contexte de l'examen des aides d'Etat pour le mécanisme de réserves stratégiques.

Situation en Belgique

Compte tenu de leur impact significatif sur l'adéquation, il est toutefois important de prendre en compte le scénario 'HiLo'. De précédentes analyses comparant la disponibilité nucléaire en Belgique modélisée dans le scénario 'base case' et la disponibilité réelle ont démontré que ces événements ayant un grand impact, à faible probabilité, peuvent être pris en compte en considérant une sensitivité caractérisée par l'indisponibilité additionnelle de 1,5 GW sur le parc de production nucléaire en Belgique. Cette capacité est considérée comme indisponible pendant tout l'hiver, et ce, en plus de la maintenance déjà prévue et prise en compte dans le scénario 'base case' et des indisponibilités fortuites simulées.

Situation en France

Pareillement, l'indisponibilité du parc de production nucléaire français a un impact important sur l'adéquation en Belgique, comme observé durant l'hiver 2016-17 où plusieurs unités ont été temporairement mises hors service à la demande de l'Autorité de Sûreté Nucléaire française. Par conséquent, en continuité avec l'approche de l'année dernière, dans le scénario 'HiLo', une capacité de production nucléaire de 3,6 GW doit être considérée comme hors service en France pendant tout l'hiver. Cette capacité est considérée comme hors service en plus de la planification de la maintenance (REMIT) et des arrêts forcés déjà pris en compte dans le "scénario de base" pour la France.

Conclusion

En appliquant cette analyse de sensibilité, afin de saisir les événementsévénements ayant un grand impact, à faible probabilité, il n'apparaït pas nécessaire de contracter une réserve stratégique pour l'hiver 2021-22 afin de respecter les critères légaux. Le scénario 'High Impact, Low Probability' de cette étude conduit à une marge de 0 MW avec un LOLE moyen proche de 3h et un LOLE95 de 18h.

Cette conclusion reflète une situation légèrement plus défavorable pour la Belgique comparativement à la prévision précédente pour l'hiver 2020-21, datant du rapport sur les réserves stratégiques de novembre 2019. Cette tendance peut s'expliquer par la combinaison de plusieurs facteurs : outre l'impact de la COVID-19 sur la disponibilité du nucléaire en France, l'hypothèse a été faite que la crise de la COVID-19 a également réduit la demande d'électricité en Europe.

Cependant, ce résultat est indissociable des hypothèses considérées, tant pour la Belgique que pour les pays voisins. Le risque d'arrêts planifiés supplémentaires renforce la recommandation d'Elia de prendre une décision basée sur le scénario "High Impact, Low Probability". Étant donné les résultats à 0 MW, des situations réelles qui vont même au-delà des hypothèses considérées pourraient conduire à un problème d'adéquation pour la Belgique et à un besoin correspondant de réserve stratégique. les hypothèses retenues concernant l'indisponibilité prévue du parc de production belge sont basées sur les dernières informations sur les canaux de transparence de marché pertinents (REMIT);

La Belgique reste dépendante des importations pour son approvisionnement en électricité. Par conséquent, toute modification des hypothèses pour les pays voisins - liée à leurs capacités d'exportation ou à leurs besoins d'importation - aura potentiellement un impact sur la Belgique et sur le volume de réserve stratégique associé. La disponibilité maximale de la production nationale pendant la période hivernale est cruciale pour que la Belgique puisse maintenir son adéquation. Par conséquent, Elia invite les propriétaires d'unités de production à éviter toute maintenance planifiée de leurs unités pendant la période hivernale.

Recommandation au Ministre

Afin de prendre une décision sur le volume à constituer pour la réserve stratégique pour l'hiver prochain (2021-22), Elia recommande de prendre en compte le scénario incorporant des événements ayant un grand impact, à faible probabilité, sur l'adéquation de la Belgique. Cette approche a été approuvée par la Direction Générale de la concurrence de la Commission Européenne dans le contexte de l'examen des aides d'Etat pour le mécanisme de réserves stratégiques.

Ce scénario comprend une réduction de l'indisponibilité nucléaire pendant tout l'hiver de 1,5 GW en Belgique et de 3,6 GW en France; en plus de l'indisponibilité planifiée comme communiquée par les propriétaires des unités de production en Belgique et en France et des probabilités d'arrêts fortuits déterminées de manière statistique.

Concrètement, le scénario recommandé par Elia conduit à une marge de 0 MW pour la Belgique pour l'hiver prochain (2021-22). Par conséquent, ce scénario n'induit pas la nécessité de constituer une réserve stratégique pour l'hiver 2021-22.

Un regard vers l'avenir

Pour **l'hiver 2022-23**, les dates définies dans la législation relative à la sortie du nucléaire ont été prises en compte. Conformément à l'article 4 de la loi sur la sortie du nucléaire, Doel 3 doit être arrêté d'ici le 1er octobre 2022 et Tihange 2 d'ici le 1er février 2023. Pour tenir compte du démantèlement de la centrale nucléaire en Belgique, la sensitivité HiLo correspondante sera composée de deux niveaux, 1,5 GW pour la première partie de l'hiver lorsque la capacité installée globale s'élève à 5 GW et 1 GW à partir du démantèlement de Tihange 2, ce qui porte la capacité nucléaire installée en Belgique à environ 4GW. En suivant les politiques nationales, la tendance nette en termes de capacité de production thermique en Europe montre un démantèlement global d'environ 16 GW. Cette tendance s'observe principalement dans les pays voisins: l'Allemagne prévoit le démantèlement de 8 GW de centrales au charbon, au lignite et de centrales nucléaires alors que la Grande Bretagne annonce le démantèlement de 4 GW de centrales au charbon et de centrales nucléaires. Ceci entraîne donc une réduction de la production disponible pour les importations belges. Cette réduction est en partie compensée par une augmentation du volume de production renouvelable, de market response, des installations de stockage et de la capacité d'interconnexion disponible sur le marché (évolution du minRAM). Cette situation conduit néanmoins à **un besoin** identifié de **800 MW** en hiver 2022-23.

Pour **l'hiver 2023-24**, la sensibilité HiLo pour la Belgique représente une indisponibilité nucléaire supplémentaire de 1 GW pour tout l'hiver. Selon les hypothèses actuelles, Elia a calculé que le **besoin** pour le système belge dans le cadre du scénario 'HiLo' est **de 100 MW**. Cette diminution par rapport à l'hiver 2022-23 peut s'expliquer par plusieurs facteurs, l'évolution de la trajectoire minRAM vers 70 % augmentera la taille des domaines flow-based, **la mise en service prévue de nouvelles centrales thermiques** (par exemple Flamanville en France, la nouvelle capacité gazière au Royaume-Uni), **l'ajout de capacités renouvelables** et enfin **l'augmentation supposée du market response**, **du stockage et de la cogénération dans la plupart des pays** (dont plus de 300 MW de nouveau stockage, 300 MW de nouvelle réponse du marché et 100 MW de nouvelle cogénération en Belgique par rapport aux chiffres actuels) **sans aucune garantie que ces capacités seront disponibles d'ici là**.

En outre, et compte tenu de la dépendance de la Belgique à l'égard des importations, les futures capacités d'exportation des pays voisins continueront d'avoir un impact clé sur la situation d'adéquation attendue et sur le besoin de capacités nationale en Belgique. Il est important de garder à l'esprit que le mécanisme de réserve stratégique actuel n'a été approuvé par la Commission européenne que jusqu'à l'hiver 2021-2022. Nous constatons donc que, selon cette étude, il existe un besoin de capacité identifié pour les années 2022-2023 et 2023-2024, sans qu'il y ait un mécanisme (approuvé) pour cette période. Nous souhaitons attirer l'attention des autorités publiques sur ces observations et restons à leur disposition pour les soutenir dans toute réflexion ultérieure sur la question.

Elia tient à souligner que les conclusions de ce rapport sont indissociables des hypothèses mentionnées dans celui-ci. Elia ne peut garantir que ces hypothèses se matérialiseront réellement. Dans la plupart des cas, il s'agit de développements qui échappent au contrôle direct ou à la responsabilité de l'opérateur du système.

1 Introduction

A strategic reserve mechanism has been in place since 2014[2] to shore up Belgium's electricity security during the winter period. This mechanism entails several tasks and responsibilities for Elia as the country's system operator. One such task is to determine the need for a strategic reserve by carrying out a probabilistic assessment. This report sets out the results of the assessment of the 2021-22 winter period that Elia is required to conduct by 15 November 2020. Elia previously carried out assessments for the winters 2014-15 up to and including 2020-21. These documents are available to the public on the website of the Directorate-General for Energy at FPS Economy [1]. This report builds further on previous editions. As such, it follows the same general structure.

Chapter 1 presents the relevant background and context, provides an overview of the roles and responsibilities of the various parties and describes the communications and consultations with stakeholders regarding this report.

Chapter 2 sets out the method and framework used for the probabilistic assessment. The application of this method is covered in Chapters 0 and 4, which take an in-depth look at the assessment's key parameters and assumptions. The focus here is on available generation resources, energy consumption in Belgium and the situation in neighbouring countries.

Chapter 5 presents the assumptions regarding interconnection capabilities for Belgium and neighbouring countries.

Chapters 6 sets out the results of the assessment for winter 2021-22, providing an in-depth analysis of the 'base case' scenario and of a sensitivity scenario based on the availability of nuclear power in Belgium and France. The sensitivity scenario is defined to account for the occurrence of 'low-probability, high-impact', yet realistic, events.

Chapter 7 sets out the conclusions of this report, and Chapter 8 contains the appendices on modelling details and adequacy parameters.

[2] In 2018, the European Commission approved the Belgian strategic reserve mechanism until winter 2021-22 (inclusive) in the context of compliance with the State aid guidelines (EEAG).

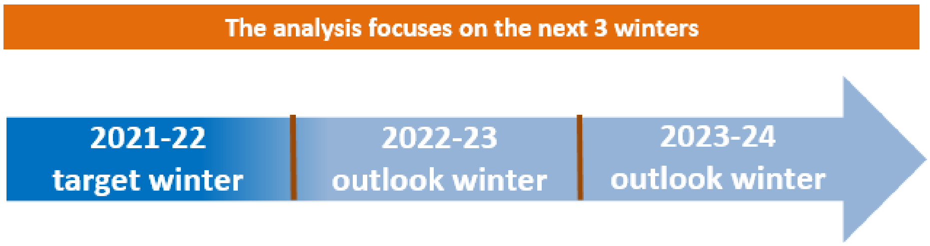

Figure 1.1

1.1 Roles and responsibilities

As Belgium's transmission system operator for the high-voltage grid (30 to 380 kV), Elia plays a crucial role in society, its **three core activities** (see Figure 1.2) ensuring the reliable transmission of electricity, both now and in the future.

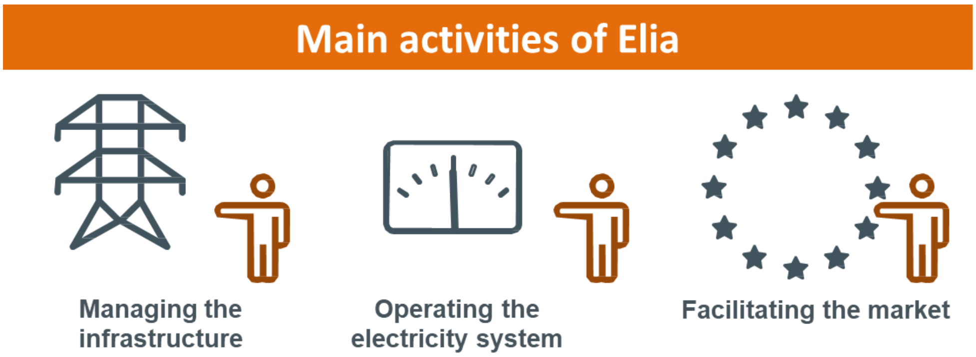

Figure 1.2

1.1.1 Operating the electricity system

This task is becoming increasingly challenging. Accordingly, special skills and sophisticated tools and processes are needed to keep the system balanced 24 hours a day, all year round. Since there is no way of storing large volumes of electrical energy, that balance has to be maintained in real time to ensure a reliable power supply and guarantee the efficient operational management of the high-voltage grid. Managing the strategic reserve is part of this task.

Balancing supply and demand

In any electricity system, generated energy must always match consumed energy. If there are any differences between them, the grid's frequency will either rise (when generation exceeds consumption) or fall (when consumption exceeds generation). One of Elia's roles is to maintain this balance at all times.

Figure 1.3

1.1.2 Managing the infrastructure

Power plants used to be built near cities and industrial areas, but since the advent of renewable energy sources, the distances between power generating facilities and centres where energy is consumed have increased significantly. Offshore wind farms are a good example of this. Energy distribution and transmission systems need to be expanded to integrate renewables into the energy mix and ensure that electricity flows from north to south and from west to east. Elia deploys innovative technologies to boost the efficiency and reliability of its electricity system and manages its infrastructure in a cost-efficient way, while always focussing on safety.

1.1.3 Facilitating the market

Elia makes its infrastructure available to the market in a transparent, non-discriminatory way, develops new products and services to improve the liquidity of the European electricity market, and builds new connections to provide the market with new options. In doing so, Elia promotes competition between market players and encourages the more efficient use of the energy sources available in Europe, to boost the economy and improve welfare for all.

Besides Elia, many other key players contribute to the organisation of the Belgian electricity market. Here is a brief overview:

- **Generators/suppliers** are committed to meeting their customers' energy needs. They make sure their generation or import capacity is sufficient for meeting their obligations to customers.
- **Balance responsible parties** (BRPs[3]) balance their customers' injections and offtakes every quarter of an hour.
- **Distribution system operators** (DSOs) manage the distribution of electricity to the businesses and private customers connected to their grid.
- The **federal government** determines general policy, including policy on the security of the energy supply.

[3] These may be generators, major consumers, electricity suppliers or traders, among other parties.

— The **federal regulator CREG**[4] advises public authorities on the organisation and operation of the electricity market and fulfils the general task of supervising and monitoring the enforcement of relevant legislation and regulations.

1.2 Legal framework and process[5]

Articles 7bis to 7sexies of the Law of 29 April 1999 on the organisation of the electricity market ('Electricity Act') include the following **timetable** for determining the volume of the strategic reserve (see also Figure 1.4):

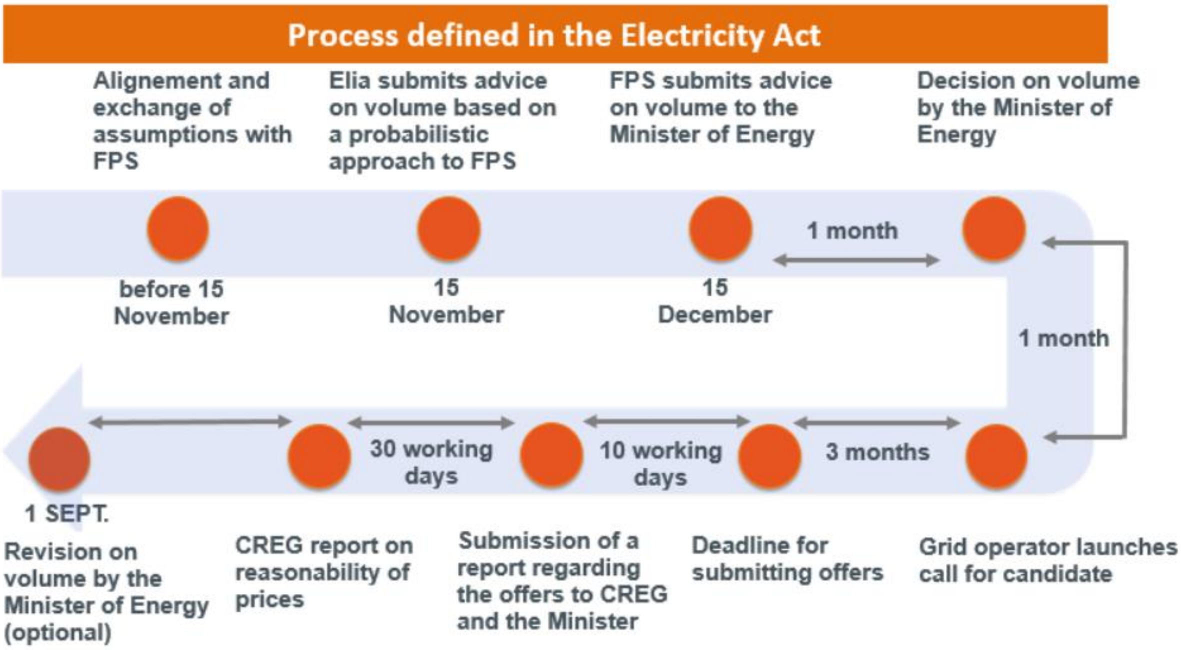

Figure 1.4

Art.7bis – 7sexies

— ***Prior to 15 November***: *DG Energy*[6] *provides the grid operator with any relevant information for the probabilistic assessment.*

— ***By 15 November***: *The grid operator carries out a probabilistic assessment which is submitted to DG Energy.*

— ***By 15 December***: *DG Energy provides the Minister with an opinion on the need to constitute a strategic reserve for the following winter. If the opinion concludes that such a need exists, a volume for this reserve is suggested, expressed in MW.*

— ***One month after receiving DG Energy's opinion***: *The Minister may instruct the grid operator to constitute a strategic reserve for a period of one year starting from the first day of the next winter period, and determines*

[4] CREG = Commission for Electricity and Gas Regulation
[5] Some texts in this section are taken from the Electricity Act and are not available in English (only in French and Dutch). They are translated from those languages for the reader's information. Elia assumes no responsibility for the accuracy of the translation of these legal articles and, in case of any doubt, the original text prevails over these translations. This also applies to other translations from the Electricity Act provided in this report.
[6] Directorate-General for Energy at Federal Public Service (FPS) Economy

the size of this reserve in MW. The Minister notifies CREG of this decision. The decision, the grid operator's assessment and DG Energy's opinion are published on DG Energy's website.

- ***One month after the Minister's instruction**: The grid operator starts the procedure for constituting strategic reserves. Offers should be submitted within three months after the start of this procedure.*
- ***10 working days after the latest submission date of offers**: The grid operator submits a report to CREG and the Minister regarding all received and valid offers.*
- ***30 working days after receipt of the grid operator's report:** CREG issues an advice that explicitly and in a motivated way indicates whether or not the price of all valid offers is manifestly unreasonable.*
- ***By 1 September:** The Minister may revise the required volume of the strategic reserve if the circumstances regarding the security of supply have changed, based on an updated analysis by the grid operator and advice from DG Energy.*
- ***After 1 September**: The grid operator makes a technical and economic selection of offers from those not deemed manifestly unreasonable by CREG and concludes contracts with the selected party to the extent of the volume set by the Minister.*
- ***By 15 September:** If the total volume of offers whose prices are not deemed manifestly unreasonable is insufficient to reach the required volume, the grid operator reports the need for additional volume to the Minister, DG Energy and CREG.*
- ***10 working days after receipt of the grid operator's report**: DG Energy submits potentially imposable prices and volumes to the Minister.*
- *For reasons to do with security of supply, the King may issue a Royal Decree imposing prices and volumes on one or more suppliers whose offer CREG deemed to be manifestly unreasonable*.

The Electricity Act also stipulates that the **probabilistic assessment** should bear in mind the following **aspects** determining the security of Belgium's energy supply for the winter ahead:

Article 7 bis §4

- *the level of security of supply to be achieved;*
- *the generation and storage capacities that will be available in the Belgian control area, based on such factors as scheduled cases of decommissioning in the development plan referred to in Article 13, and the communications received pursuant to Article 4bis;*
- *electricity consumption forecasts;*
- *possibilities for importing electricity, given the capacities of the interconnectors available to Belgium, and, if need be, an assessment of the availability of electricity in the Central West European electricity market;*
- *the grid operator may, subject to appropriate justification, supplement this list with any other item deemed useful.*

1.3 Adequacy criteria

The Electricity Act describes the level of security of supply (i.e. adequacy) that Belgium needs to achieve. In the absence of harmonised European or regional standards, this level is determined by a **two-part loss of load expectation (LOLE) criterion** (see Figure 1.5). The model Elia uses for the probabilistic assessment enables both indicators to be calculated.

Adequacy criterion

LOLE < 3 hours

LOLE95 < 20 hours

Figure 1.5

Art.2, 52° - 53°

- ***LOLE****: A statistical calculation used as a basis for determining the anticipated number of hours during which, even taking account of interconnectors, the generation resources available to the Belgian electricity grid will be unable to cover the load[7] for a statistically normal year.*
- ***LOLE95****: A statistical calculation used as a basis for determining the anticipated number of hours during which, even taking account of interconnectors, the generation resources available to the Belgian electricity grid will be unable to cover the load for a statistically abnormal year.*[8]

How to interpret adequacy criteria

The indicative Figure 1.6 below shows how to interpret adequacy criteria. The probabilities of a large number of future states are calculated for a given winter (see section 8.1.1). For each future state, the model calculates the LOLE for the winter in question. The distribution of the LOLE across all the future states included can then be extracted.

For the first criterion, the average is calculated based on all these LOLE results[9]. For the second criterion (95th percentile), all the LOLE results are ranked. The highest value, after the top 5% of values have been disregarded, gives the 95th percentile (a 1 in 20 chance of such a loss of load expectation). The Electricity Act stipulates that **both criteria need to be satisfied for Belgium**.

In addition to the two criteria set out in the Electricity Act, the 50th percentile is also shown for all the results. This indicator shows a 1 in 2 chance of at least a given LOLE. The figure below also includes the 50th percentile, which except for in a few rare cases, is generally not the same as the average LOLE.

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[7] Load = demand for electricity

[8] There is a 1 in 20 chance of a statistically abnormal year (95th percentile).

[9] The average value for of a series of numbers (LOLE for each status) is calculated by totting them up and dividing the result by the number of numbers in the series.

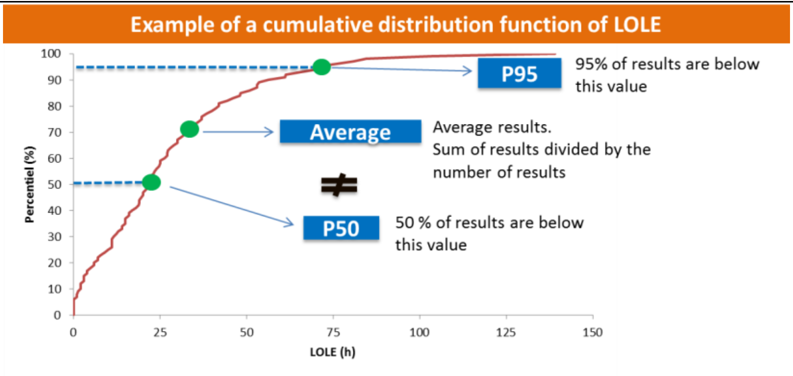


Figure 1.6

Depending on the values of these indicators, four situations can be derived from the results as represented in the table in Figure 1.7 below.

LOLE average	LOLE P95	LOLE P50	Situation
0	0	0	*No LOLE in any of the future states*
>0	0	0	*LOLE in less than 5% of the future states*
>0	>0	0	*LOLE in more than 5% of future states but less than 50%*
>0	>0	>0	*LOLE in more than 50% of the future states*

Figure 1.7

In addition to covering the indicators outlined above, which only take account of the number of hours when a full energy supply cannot be provided, the model used by Elia also gives an indication of the scale of the energy shortage (energy not supplied, abbreviated ENS) during these hours and the likelihood of a loss-of-load situation occurring (loss of load probability, abbreviated LOLP):

- **ENS:** The volume of energy that cannot be supplied during hours when a loss of load occurs. This yields average ENS (for a statistically normal year) and ENS95 (for a statistically abnormal year), expressed in GWh per annum.
- **LOLP**: The probability of a loss-of-load situation occurring at a given time, expressed in percent.

To fulfil both legal criteria regarding security of supply, the required strategic reserve capacity is calculated based on an assumption of 100% availability. No distinction is made between demand reduction (SDR[10]) and generation capacity (SGR[11]):

- Where SGR is concerned, the assumption of 100% availability means that the strategic reserve will never require maintenance during the winter, nor will any unscheduled outage occur. This differs from how units available in the market are modelled.
- Where SDR is concerned, the assumption of 100% availability means that the strategic reserve can be called upon at any time throughout the winter, with no restriction on the number of activations or their duration.

The assumption of 100% availability of the SGR is important, especially where large volumes are involved, as a cold spell (occurring when the need for strategic reserve is at its greatest) may cause start-up problems for old generation

[10] SDR = strategic demand reserve
[11] SGR = strategic generation reserve

units. The assumption of 100% availability of the SDR is equally important, as operational requirements may restrict the number and duration of activations.

Further information about the strategic reserve product and the operational requirements can be found on Elia's website [3].

1.4 General background information on the strategic reserve

1.4.1 How is a risk to security of supply identified operationally?

The potential security of supply risk in Belgium is assessed every day for the seven days ahead. The items deterministically assessed to ascertain whether there is an increased risk include:

- renewable energy generation forecasts;
- the latest information at Elia's disposal regarding the availability of conventional generation units;
- an appraisal of potential levels of imports;
- forecasts of Belgium's total electricity consumption.

These assessments are repeated, with forecasts becoming increasingly accurate the nearer they become to real time. Since the potential risk is determined on the basis of assumptions and forecasts, there is no absolute certainty that a shortage will actually occur.

1.4.2 If a risk to security of supply is identified, how is it communicated?

If the aforementioned assessments indicate a potential risk to the security of supply in Belgium, it is communicated to the relevant authorities and to the general public. The 'power indicator' on Elia's website and the 'Elia4cast' app were specially developed to communicate information [4] to the general public (see Figure 1.8).

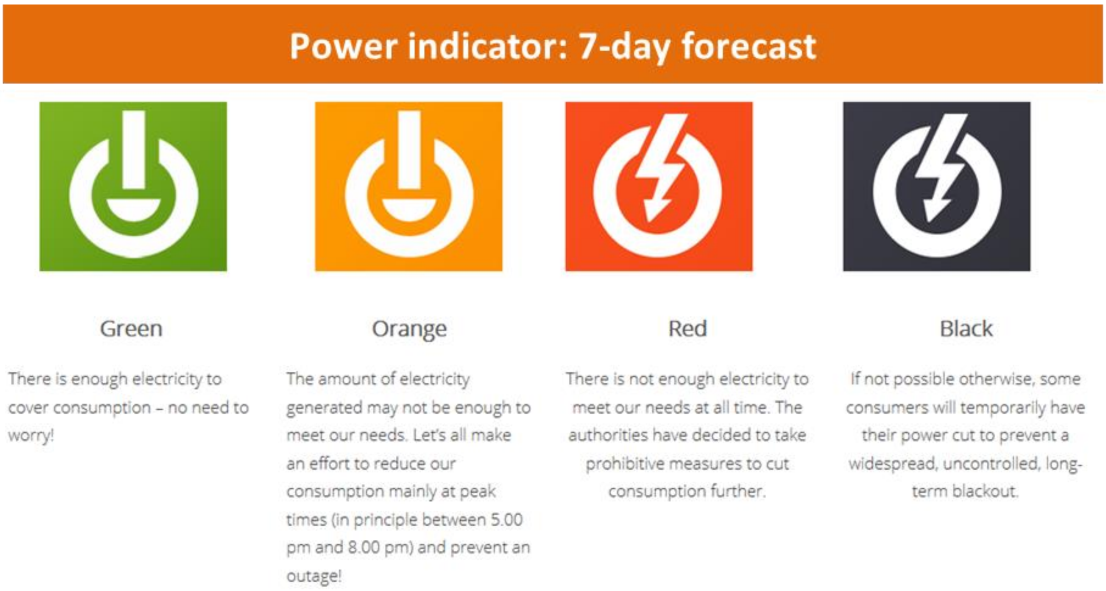


Figure 1.8

At the same time, when a structural shortage[12] is identified, this may prompt the activation of the strategic reserve. Notification of any such activation is published on Elia's website. The strategic reserve is activated by a technical trigger. Further information about this can be found in the rules governing the functioning of the strategic reserve [3].
The strategic reserve is distinct from the usual mechanisms involving a balancing reserve that remedies immediate, unexpected imbalances, and thus maintains the balance in the Belgian control area at all times (see section 3.1.5)

Activation of the strategic reserve does not necessarily mean there is, or will be, a power outage. The strategic reserve is simply an extra means for avoiding any interruption in the power supply.

1.4.3 What measures will be taken if security of supply is jeopardised?

If Belgium's supply margins become drastically reduced (or even disappear altogether), a number of measures can be taken to tackle the problem (see Figure 1.9):

- A request to supply potential **additional uncontracted reserve volumes** will be sent to all balance responsible parties to allow Elia to call on any residual capacity at an available power plant or deploy extra means to control electricity consumption. Elia does this by using an RSS[13] feed to post a balancing warning on the web.
- If necessary, Elia will assess whether special measures can be taken in coordination and collaboration with the other transmission system operators (TSOs) in the CWE area[14] to further increase Belgium's **import capacity**.
- Activation of Belgium's **strategic reserve** if any were contracted.
- If appropriate, Elia will draw on its **contracted balancing reserve volumes**. This involves such wide-ranging measures as activating special quick-start gas units, invoking contracts with aggregators[15], reducing the consumption of industrial customers and requesting assistance from neighbouring TSOs.
- If market mechanisms and reserves prove insufficient, the authorities may decide to restrict **electricity consumption**. Steps to raise awareness, possibly coupled with prohibitive measures, may be taken first, to maintain grid balance over the hours or days ahead.
- One final measure for avoiding an uncontrolled general blackout across Belgium entails the controlled deployment of the **load-shedding plan**, with the ministers responsible for energy and economic affairs taking a decision on this the evening before the plan is activated.

NB: These measures will not necessarily be taken consecutively and are taken by various entities (TSO, ministry, etc.).

[12] A structural shortage as defined in the rules governing the functioning of the strategic reserve [3] is a situation in which total consumption within the Belgian control area cannot be covered by the available generation capacity there, excluding balancing reserves and bearing in mind potential imports and energy available on the market.
[13] RSS = really simple syndication
[14] CWE: Central West Europe
[15] An aggregator is a demand service provider that combines multiple short-duration consumer loads for sale or auction in organised energy markets.

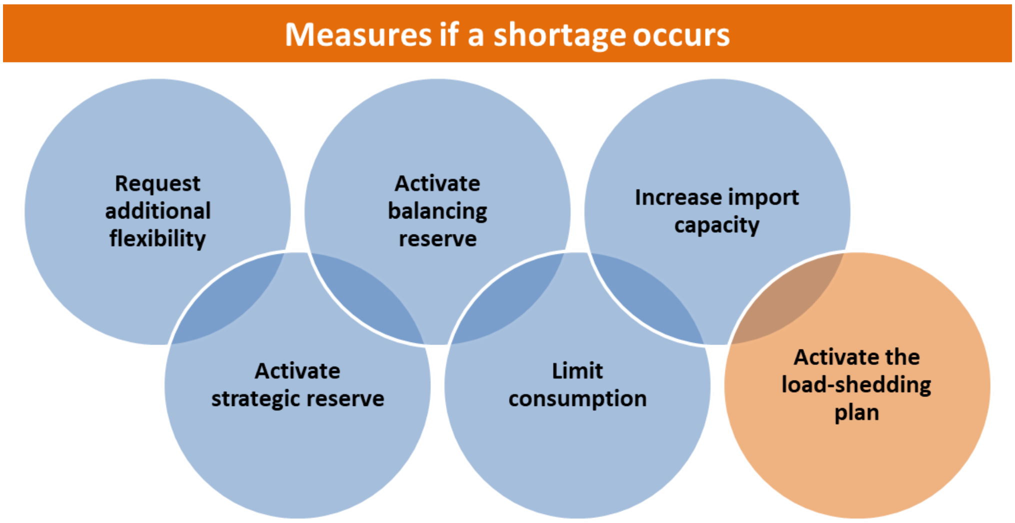


Figure 1.9

1.4.4 Under what circumstances will the load-shedding plan be activated?

The load-shedding plan is a measure of last resort that can be used if all other mechanisms for ensuring adequacy are insufficient to balance supply and demand. It is in fact an emergency plan for the years ahead, which – like any other similar plan – can be implemented at any time of the year to prevent the power grid from collapsing completely and causing a general blackout cutting off all consumers from the electricity supply. The plan entails disconnecting specifically targeted areas from the grid for a limited period to reduce power consumption.
Further practical details of the load-shedding plan (for example, regarding a specific street, the duration of the intervention, and communications in the event of an outage) can be found on the FPS Economy website [5].

What is a load-shedding plan?

The current load-shedding plan can be activated both automatically, in the event of a sudden frequency drop on the high-voltage grid, or manually, for example as last measure in case of an anticipated power shortage. This involves disconnecting DSOs' substations from the grid to keep the system balanced and prevent a general blackout across all of Belgium.
If this plan is activated, various high-voltage substations belonging to a single load-shedding group will have to be disconnected simultaneously. The load-shedding plan for Belgium was updated in 2015 resulting in eight such groups, each of which corresponds to a capacity of between 500 and 750 MW. In total, they account for about 35 to 40% of total peak consumption. The updated load-shedding plan has been operational since 1 November 2015.
The load to be disconnected within each group is proportionally distributed over 5 zones of Belgium, meaning that municipalities from different parts of the country can belong to the same group. A single municipality – or even street – may be supplied by different DSO substations that are not part of the same group. The load shedding plan may change further depending on specific factors, such as work on the distribution grid, etc.
The **legal framework** for the load-shedding plan is set out in the ministerial decree of 3 June 2005 on the establishment of the load-shedding plan for the electricity transmission network. The load shedding plan is part of the Defence Plan pursuant to Article 312 of the Royal Decree of 19 December 2002 establishing a grid code for the management of the electricity transmission grid and access thereto. Next to the national legislation, the

Commission Regulation (EU) 2017/2196 of 24 November 2017 establishing a network code on electricity emergency and restoration also provides specific requirements concerning the load shedding plan.

1.5 History and current situation of strategic reserve constitution

Since the introduction of the strategic reserves in winter 2014-15, there have been winters with or without a contracted strategic reserve volume (see Figure 1.10).

More specifically, the strategic reserve for **winter 2014-15** comprised:

- 750 MW of SGR, for three years;
- 96.7 MW of SDR, for one year.

The strategic reserve for **winter 2015-16** partly constituted the capacity since 2014 (three-year period) and partly new reserve capacity. On 1 November 2015, the following capacity was included in the strategic reserve:

- 750 MW of SGR, since 2014;
- 427.1 MW of SGR, for one year;
- 358.4 MW of SDR, for one year.

For **winter 2016-17**, no additional volume was acquired. However, 750 MW of generation capacity was still retained (part of the three-year period since 2014). Therefore, on 1 November 2016, the strategic reserve included:

- 750 MW of SGR, since 2014.

For **winter 2017-18**, the strategic reserve comprised:

- 725 MW of SGR, for one year.

For **winter 2018-19**,

- no capacity was contracted.

For **winter 2019-20**,

- no capacity was contracted.

For **winter 2020-21**,

- no capacity was contracted.

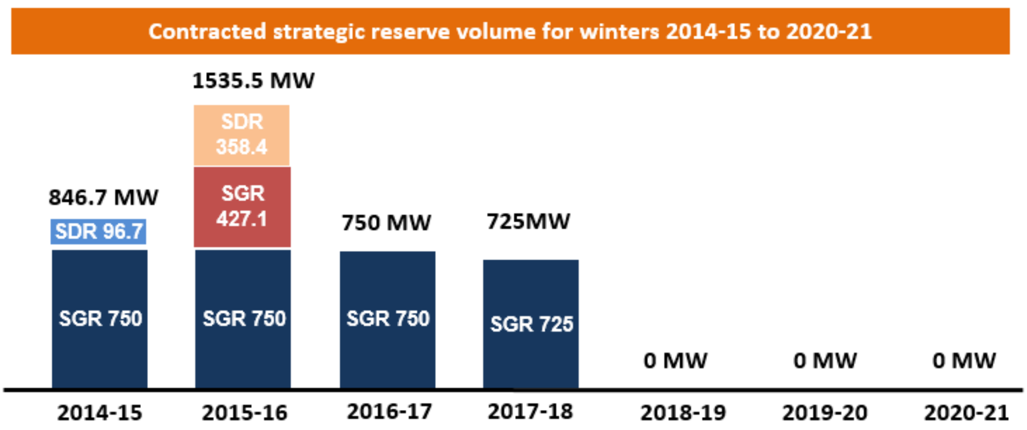


Figure 1.10

1.6 Public consultations regarding strategic reserve volume calculations

The problems Belgium could face in winter, adequacy and the strategic reserve mechanism are all becoming higher-profile issues in energy-related discussions. Due to Elia's designated roles and responsibilities, in particular regarding the strategic reserve mechanism, the company is responding to the market players' demand for a better understanding of how the strategic reserve volume is calculated and for an opportunity to have a greater say in it.
In this context, Elia launched **two public consultations** in 2020: the first on methodology, assumptions and data sources, and the second on the input data to be used for calculating the needed volume. Figure 1.11 shows when these consultations took place.

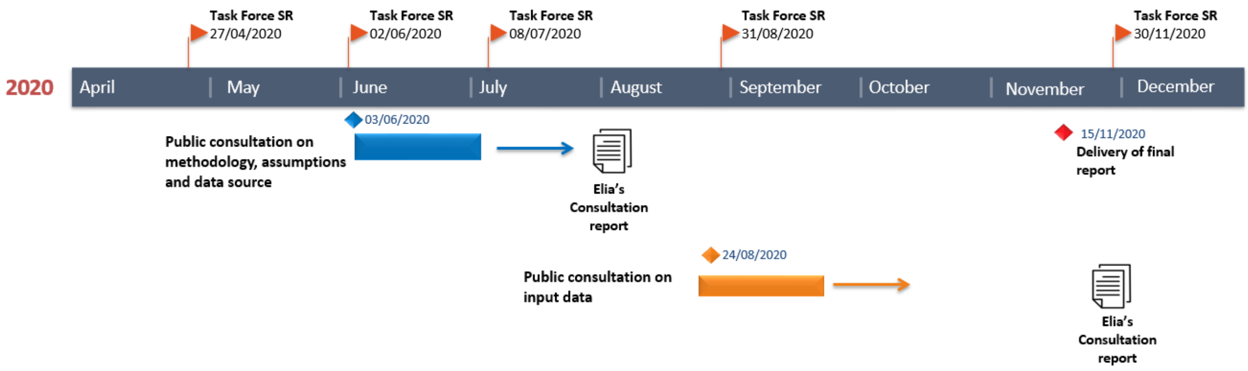


Figure 1.11

Both consultations were announced on Elia's homepage and on each occasion all the relevant stakeholders (members of the Strategic Reserve Implementation Task Force,) were informed by e-mail.

1.6.1 Feedback from stakeholders

For each consultation, the responses from the stakeholders during the consultation period can be found on Elia's website [6]. Elia replied to each response. Its replies were then aggregated and grouped by subject in two separate consultation documents. Oral explanations of its replies were given at the Task Force 'Implementation Strategic Reserve' meeting on 8 July 2020 for the first consultation, and on 30 November 2020 an overview of the received responses will be provided for the second consultation.

PUBLIC CONSULTATION 1

Content: methodology, assumptions, data sources

Consultation Period: 03 June to 1 July 2020 at 18:00

Responses received: 2

Amount of questions: 24

Subjects: Data & Assumptions, Publication of data, Publication of results, Market Response, Flow-based

Consulted document and Consultation Report: [7]

PUBLIC CONSULTATION 2

Content: Input data

Consultation Period: 24 August to 21 September 2020 at 18:00

Responses received: 3

Subjects: Data, Assumptions, Demand assumption, Market Response, Flow-based

Consulted Document and Consultation Report: [8]

Figure 1.12

1.7 Other adequacy studies with results relevant to Belgium

In addition to this report, other, similar ones deal with the same subject, though each has its own special focus, methodology and time horizon. Figure 1.13 affords a general overview. Each study is then presented in further detail below.

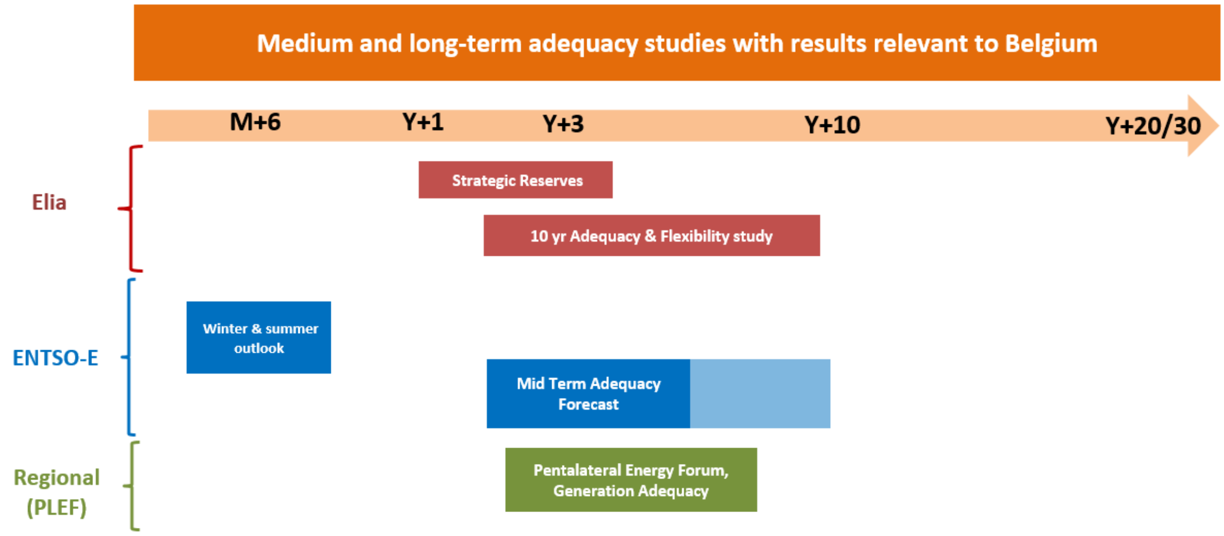


Figure 1.13

Elia is committed to ensuring a high level of consistency between the above-mentioned assessments by:

- developing and applying a common probabilistic methodology;
- ensuring the complementarity of the results obtained by different studies.

The pan-European, regional and national studies featured above share the same probabilistic methodology, therefore enabling consistent analyses and comparisons. It is also worth noting that due to the different scope, purpose and time of completion of the different studies, some updates in the methodological assumptions and data may be worth considering.

1.7.1 Elia's 10 years adequacy and flexibility study 2020-30

Elia adequacy and flexibility study 2020-2030

METHOD:	Probabilistic
TIME-FRAME:	2020-2023-2025-2028-2030
Latest publication:	06/2019
Scope	21 countries
Country results:	Belgium
Frequency of publication:	Within the updated electricity law, biannual publication. Next edition will be issued in 2021

Following the first ten year adequacy and flexibility study (2017-2027) published in April 2016 (followed by an addendum in September 2016) at the requested of the Energy Minister, a new legal requirement was inserted in the federal Electricity Act in 2018. The new law empowers the TSO to conduct a bi-annual study on the adequacy and flexibility requirements of the system for the coming ten years. The study must be published before June. The base assumptions and scenarios, as well as the methodology used for the study should be determined by the transmission system operator *in collaboration* with the FPS Economy and the Federal Planning Bureau (FPB) and *in concertation* with the Regulator.

The first edition following this new legal requirement was published in June 2019 and is available on the Elia and FPS website [9]. This study covers the horizons from 2020 to 2030 and simulates the European electricity market with the most up-to-date assumptions collected at European level. The methodology used builds on Elia expertise in the matter to which several novelties were introduced. For adequacy, the methodology is fully in line with the MAF methodology and the present study. This study is fully in line with the current legal and regulatory framework and already abides by the spirit of the new EU legislation (the Clean Energy for All Europeans package). A new methodology has also been developped to assess total flexibility requirements and whether the flexibility means are able to meet those requirements.

1.7.2 ENTSO-E: Outlook reports

ENTSO-E Winter and Summer outlooks

METHOD:	Deterministic
TIME-FRAME:	next winter/summer
Latest publication:	every 6 months
Scope	all pan EU perimeter
Country results:	all pan EU perimeter
Frequency of publication:	Twice a year

Every year, ENTSO-E[16] publishes a report entitled *Winter Outlook and Summer Review'* [10]. One of the focal points of this short-term report is the main adequacy risk for the winter ahead. The report considers various uncertainties such as climatic conditions, outages of generation units, load prospects and load management and stability issues affecting the electricity grid. It also sums up the main events from the previous summer. The purpose of the document is to establish a platform where TSOs can exchange information, create transparency and inform stakeholders about potential risks for the winter ahead.

For the winter period, the report presents an overview of the national and regional power balances between available generation capacity and forecast load. ENTSO-E gathers the information to compile this deterministic assessment using a qualitative and quantitative questionnaire completed by each individual TSO. A similar report is also published every year for the following summer period.

Ongoing discussions within ENTSO-E are geared towards seeing the report develop into a probabilistic assessment.

1.7.3 ENTSO-E: Mid-Term Adequacy Forecast

ENTSO-E Mid Term Adequacy Forecast

METHOD:	Probabilistic
TIME-FRAME:	2025 - 2030
Latest publication:	end 2020
Scope	all pan EU perimeter
Country results:	all pan EU perimeter
Frequency of publication:	Yearly

In 2016, the first *Mid-Term Adequacy Forecast* (MAF) was published following a probabilistic method like the one Elia uses to assess the volume of strategic reserve. The latest published edition of the MAF report at the time of the

[16] ENTSO-E = European Network of Transmission System Operators for Electricity Organisation, representing 41 TSOs from 34 European countries

publication of this report is still MAF 2019, which was published in November 2019 [13], giving stakeholders in the European energy market an overview of the national and European adequacy situation. The MAF 2020 is expected to be published by the end of 2020. The MAF assessment generally uses best-estimate scenarios based on bottom-up data collection from TSOs, and focuses on the LOLE and ENS as adequacy indicators.

The MAF report will now evolve into the European Resource Adequacy Assessment (ERAA) as of 2021. However the current MAF2020 report does not comply with important elements of the ERAA methodology, notably, but not limited to, an economic viability assessment and the implementation of the flow-based methodology.

1.7.4 Pentalateral Energy Forum (PLEF): Regional Generation Adequacy Assessment

Penta Lateral Energy Forum Adequacy study

METHOD:	Probabilistic
TIME-FRAME:	2025
Estimated publication:	May 2020
Scope	all pan EU perimeter
Country results:	AT,BE,CH,DE,FR,LU,NL
Frequency of publication:	ad hoc request by PLEF Ministries

The TSOs belonging to the PLEF (BE, DE, FR, LU, NL, AT and CH) region published a regional adequacy study in early 2015, based on suitable probabilistic methodology (the same as used by Elia). This study assesses the main adequacy indicators (LOLE and ENS), both for the countries covered and for the entire region. The study analysed both winter 2015-16 and winter 2020-21 and was published in March 2015.

The second PLEF adequacy assessment was published in early 2018 and covered winters 2018-19 and 2023-24.

The third PLEF study was carried out by late 2019 and early 2020 and was published in May 2020. The study covered the year 2025 and focused on regional sensitivities which provided realistic ‘stress test’ situations for the region. The definition of the sensitivities was performed in collaboration between Ministries, Regulators and TSOs in the PLEF group. Also the flow-based methodology used in the PLEF study was the same as developed by Elia in its latest ‘Adequacy and flexibility study for Belgium 2020 – 2030’ report which included the 70%CEP rule.

1.8 Disclaimer

This report provides a probabilistic assessment of Belgium's security of supply and the need for strategic reserves for the winter 2021-22, with an outlook for winters 2022-23 and 2023-24. The assessment is based on the following key assumptions:

- Within the calculated volume, no distinction is made between demand reduction and generation capacity. The calculated volume is considered to be 100% available.
- The volume calculation disregards the possibility of actually being able to find this volume in the Belgian market.

Elia would like to stress that the conclusions of this report are inextricably linked to the initial assumptions set out in it. Elia is not liable for the realisation of these assumptions, as in most cases they relate to developments falling outside the direct control of the grid operator.

2 Methodology

The volume of strategic reserve needed for a specific winter is determined using the iterative process depicted in Figure 2.1. First it is ascertained whether a margin or necessary strategic reserve volume has been identified for the situation under consideration. If one of both relevant legal criteria are not met, then additional strategic reserve volume is needed. On the other hand, if the simulation without any additional volume of strategic reserve already complies with both legal criteria, the margin on the system will be examined.

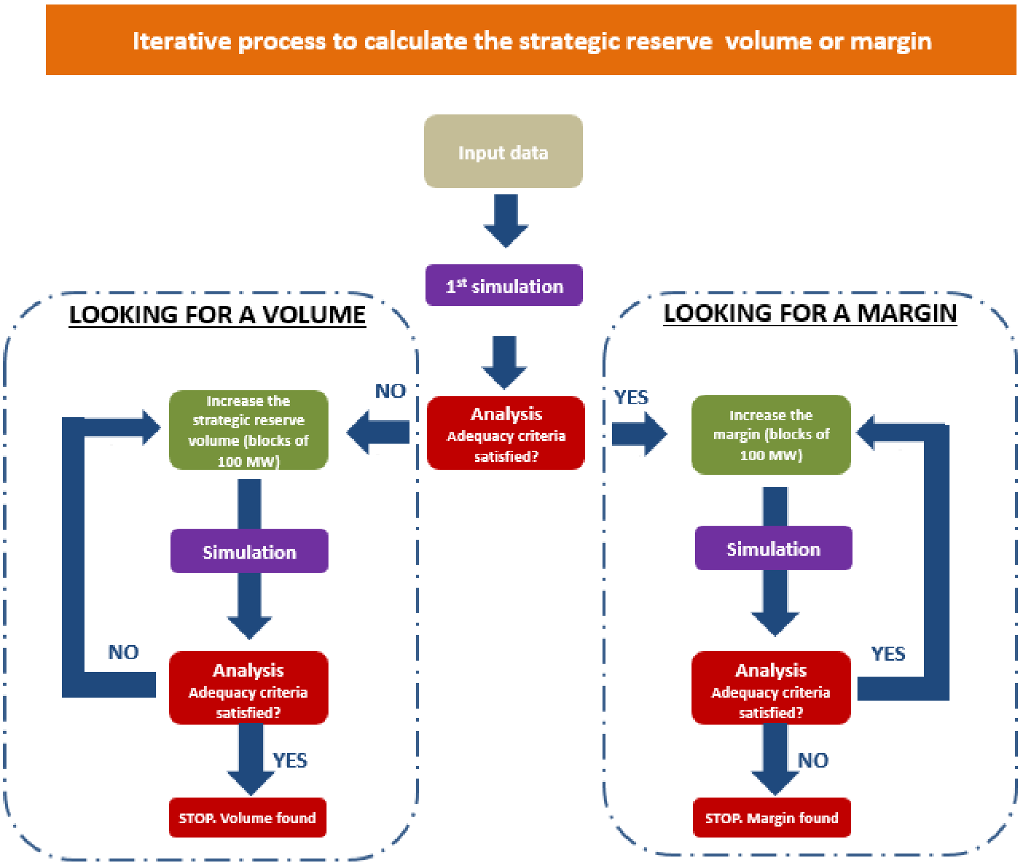


Figure 2.1

This chapter briefly summarises how the probabilistic simulation is performed. The whole simulation process, as well as the tools and methods used, are described in greater **detail in the appendix** (section 8.1).

2.1 Probabilistic simulation of the Western-European electricity market

As Belgium depends on electricity imports for its security of supply, the modelling has to include the neighbouring countries. This study involved the individual modelling of 23 countries. This makes it possible to determine the available generation capacity abroad when Belgium needs to import energy. The countries are listed below, and shown in Figure 2.2:

- Austria (AT)
- Belgium (BE)
- Switzerland (CH)
- the Czech Republic (CZ)
- Germany (DE)
- Denmark (DK)
- Spain (ES)
- France (FR)
- United Kingdom (GB and NI)
- Hungary (HU)
- the Republic of Ireland (IE)
- Italy (IT)
- Luxembourg (LU)
- the Netherlands (NL)
- Norway (NO)
- Poland (PL)
- Portugal (PT)
- Slovenia (SI)
- Slovakia (SK)
- Sweden (SE)
- Finland (FI)
- Romania (RO)
- Croatia (HR)

Due to the specific market situation in Italy, Denmark, Norway and Sweden, these countries are modelled using multiple market nodes. This type of specific modelling is in line with the real market situation, and is identical to the approach used in other studies, e.g. at ENTSO-E.

For the probabilistic simulation, 23 countries are modelled individually

Figure 2.2

At each iteration of the adequacy assesment, a full probabilistic simulation of the Western European electricity market is carried out. Three steps are performed: the first step is the definition possible future states (or 'Monte Carlo' years). This is described more in detail in section 2.2. The second step is the identification of structural shortage periods. Here, the hourly output of this simulation is analysed to determine whether the two adequacy criteria are fulfilled. Section 2.3 sets out how hours in which a structural shortage is present are identified. The third step, detailed in section 2.4, is the assesment of the additional capacity need. Depending on whether a margin or a needed volume of strategic reserve is sought, the iterative process is halted as specified in Figure 2.1.

2.2 Definition of future states

Each future state (or 'Monte Carlo' year) is a combination of:

- **Historical climate conditions** for temperature, wind, sun and precipitation. These data are used to create a time series of renewable energy generation and consumptionby taking into account the 'thermosensitivity' effect. The correlation between climate variables is retained both **geographically and time-wise**. For this reason, the climatic data relating to a given variable (wind, solar, hydroelectric or temperature) for a specific year will always be combined with the data from the same climatic year for all other variables. This rule is applied to all countries in the studied perimeter;
- Random samples of **power plant and HVDC links'** (not within a meshed grid) **availability are drawn by the model** by considering the parameters of probability and length of unavailability (in accordance with the 'Monte Carlo' method). This results in various time series for the availability of the thermal facilities for each country and the availability of each HVDC link. This availability differs in each future state.

As depicted in Figure 2.3, a time series for the power plant availability will be associated to a historical 'climate year' (i.e. wind, solar, hydroelectric and electricity consumption) to constitute a 'Monte Carlo year' or 'future state'.
Each climate year is simulated a large number of times with the combination of random draws of power plant availability. Each future state year carries the same weight in the assessment. The LOLE criteria are therefore calculated on the full set of simulated future states.

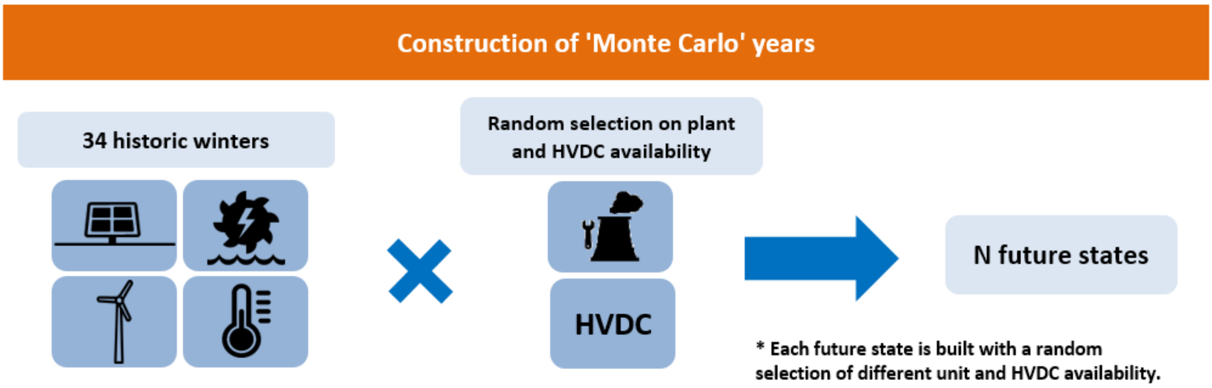


Figure 2.3

2.3 Identifying periods of structural shortage

The second part of each iteration involves identifying periods of structural shortage, i.e. times when electricity generation, storage, market response and imports are insufficient to meet demand. To this end, a probabilistic market simulation is performed.

Constructed 'Monte Carlo' years are input into the simulation of the Western European electricity market. A detailed modelling of the units' economic dispatch is performed. The assessment takes into account the units' marginal costs and also enables the pumped-storage power plants and hydroelectric reservoirs to be appropriately modelled. Economic availability depends on the generation capacity available for the hour in question. The price in any given hour is determined by the intersection between the curve for supply (called the 'merit order') and demand. Demand is considered inelastic in this context. Furthermore, the modelled adequacy assessment rightly takes account of the fact that in periods of structural shortage, all available generation, storage and market response facilities will be taken into account, operating at maximum capacity, to minimise the shortage.

The market simulator used in the scope of this study is ANTARES [11], a sequential 'Monte Carlo' multi-area simulator developed by French TSO RTE to assess generation adequacy problems and economic efficiency issues. The model's inputs and outputs are depicted in Figure 2.4.

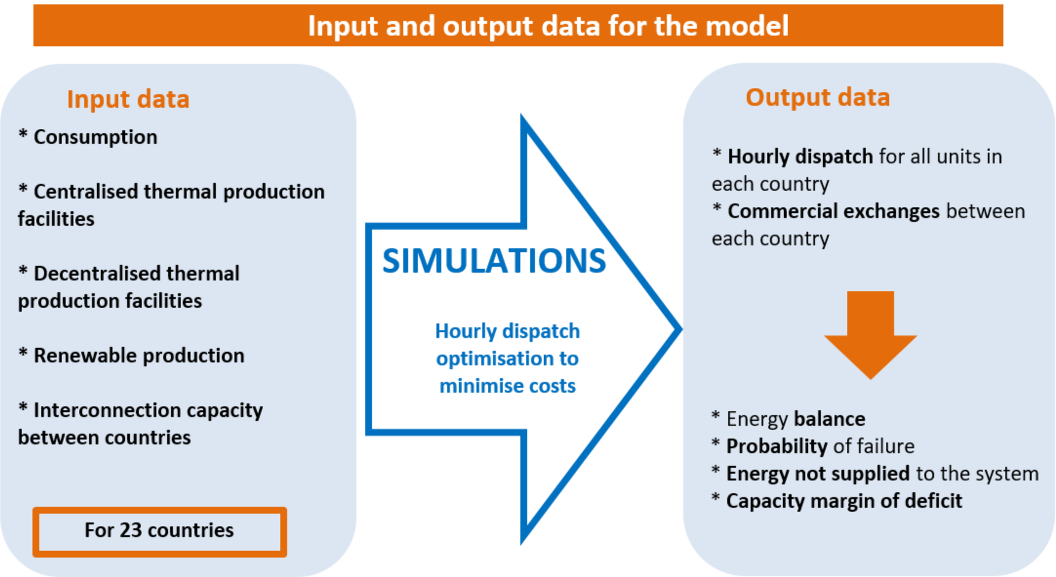


Figure 2.4

Figure 2.5 exemplifies how consumption is covered by the available generation and storage facilities and imports for every hour of the week. If, for a given hour, the combination of generation capacity, imports and market response falls short (by 1 MW or higher) of the capacity required to meet demand, this corresponds to one hour of structural shortage, or 'energy not served' (ENS) situation. Within the 'Monte Carlo' approach, the mean total of all such hours is referred to as loss of load expectation (LOLE). Figure 2.5 shows the energy that cannot be supplied by combining domestic generation and imports.

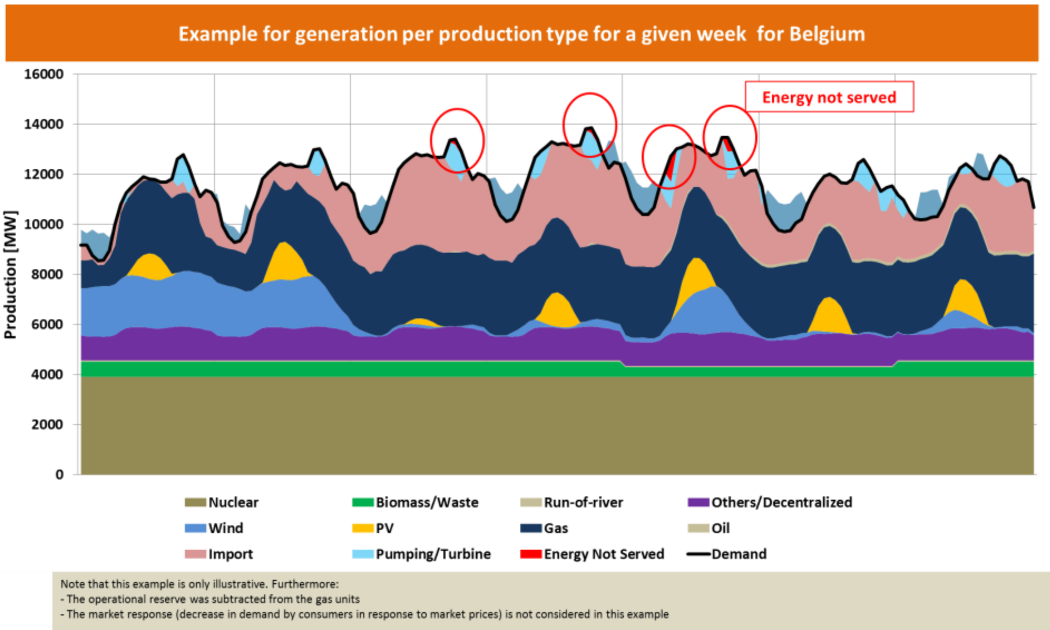


Figure 2.5

2.4 Iterative process for calculating the additional capacity need

Once the moments of structural deficit are identified for each 'Monte Carlo year', the distribution of these (quantified in hours) is established. On this basis, the adequacy criteria of the electrical system are evaluated and compared to the legal adequacy criteria (reliability standard).

If the adequacy criteria are not satisfied, **additional generation capacity** (in steps of 100 MW), **which is considered 100% available** is added to the concerned market area. The adequacy level of the new system obtained is again evaluated (definition of future states and identification of structural shortage periods with verification of the adequacy criteria). This operation is repeated iteratively, adding a fixed capacity of 100 MW (100% available) each time, as long as the legal criteria are not satisfied. On the other hand, if the simulation **without any additional generation** capacity complies with adequacy criteria, the **margin on the system is examined**.

The block size of 100 MW was chosen to be as small as possible, while still ensuring statistically robust results for the determination of the volume. Especially when searching for the tail of the distribution (e.g. P95 criterion), this statistical robustness is a limiting factor. Choosing a smaller step size might lead to a calculation result that differs depending on the random seeding of the model. The 100 MW block size is also the resolution used in the scope of the evaluation of strategic reserve volume and the other adequacy analyses performed by other TSOs and within ENTSO-E.

3 Assumptions about the power supply and electricity consumption in Belgium

This chapter elaborates the assumptions used in this analysis for Belgium. Section 3.1 details the hypotheses used with regard to the Belgian electricity supply. Section 3.2 details the demand for electricity in Belgium and how its specifics are incorporated into the model. Section 3.3 and 3.4 detail respectively the Belgian market response and the installed battery capacity. Finally, section 3.5 summarizes the input data for Belgium.

Furthermore, according to Article 7quater of the Electricity Act, the Minister can review the volume for the strategic reserves no later than 1 September 2021 for winter 2021-22. Such a decision by the Minister must be based on a probabilistic 'updated analysis' by Elia with respect to the analysis performed and presented here. When preparing this updated analysis, Elia must only take account of the following information, which is sufficiently relevant to the capacity and use of facilities for the generation, storage, consumption or transmission of electricity, including the scheduled or unplanned unavailability of these facilities, e.g.:

- any inside information published in accordance with Regulation 1227/2011 on wholesale energy market integrity and transparency;
- any concrete and relevant information that entails a formal commitment by a relevant entity and is explicitly communicated to Elia by or on behalf of said entity;
- any information that the Minister explicitly asks Elia to take into consideration.

Elia organized a public consultation on the detailed assumptions used for Belgium in this analysis (see section 1.6 for more information), thereby contributing to a more transparent flow of information on the Belgian electricity system.

Elia publishes a large volume of real-time data on its website [15] to give stakeholders an overview of the Belgian transmission system. The datasets made publicly available on Elia's website include:

- the total load in Belgium and the load on Elia's grid;
- photovoltaic and wind generation data and forecasts;
- generation capacity forecasts.

These datasets, along with many others, can be downloaded for detailed analysis. Furthermore, Elia contributes to the ENTSO-E transparency platform [16] by providing real-time data.

3.1 The electricity supply in Belgium

The ANTARES model takes account of thermal generation facilities, renewable energy sources and other electricity generation for each country covered by the simulation. In line with Article 7bis of the Electricity Act, Elia received input from the Directorate-General of Energy at Federal Public Service (FPS) Economy prior to the analysis. The information received from FPS Economy is included in the report and taken on board in the analysis.

This section provides an overview of the assumptions made with regard to the Belgian electricity supply. Additional modelling details are provided in section 8.1 (appendix).

3.1.1 Wind and solar installed capacity forecasts

The FPS Economy consults Belgium's three regional authorities to obtain forecasts for the installed capacity of onshore wind and photovoltaic production. These forecasts are further detailed in sections 3.1.1.1 and 3.1.1.2. Elia uses the latest available information as a basis to consolidate a forecast of the installed capacity of offshore wind. This is further elaborated in section 3.1.1.3.

3.1.1.1 Solar

Figure 3.1 shows the historical increase in installed capacity from photovoltaic (PV) generation in Belgium and the forecast used in this analysis, which was consolidated by the FPS Economy. The average yearly increase from 2020 to 2023 is approximately 560 MW. It must be noted that while the data for 2019 is marked as 'historical', that at the time of consolidating the data no finalized inventory for 2019 was available. It is therefore possible that this data is subject to future corrections.

+ 560 MW/year on average

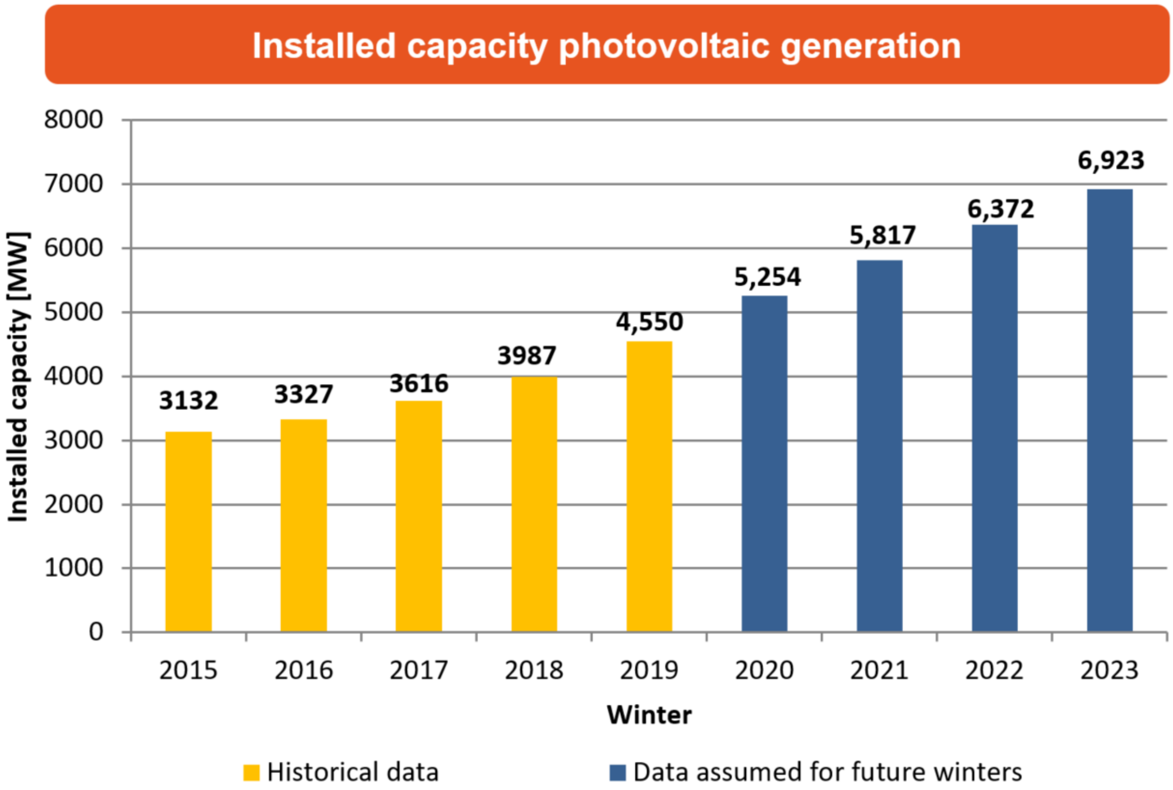


Figure 3.1

3.1.1.2 Wind onshore

Figure 3.2 shows the actual increase over time in the installed capacity from onshore wind generation and the forecast consolidated by the FPS Economy. The forecast amounts to aan average yearly increase of approximately 170 MW between 2020 and 2023.

+170 MW/year on average

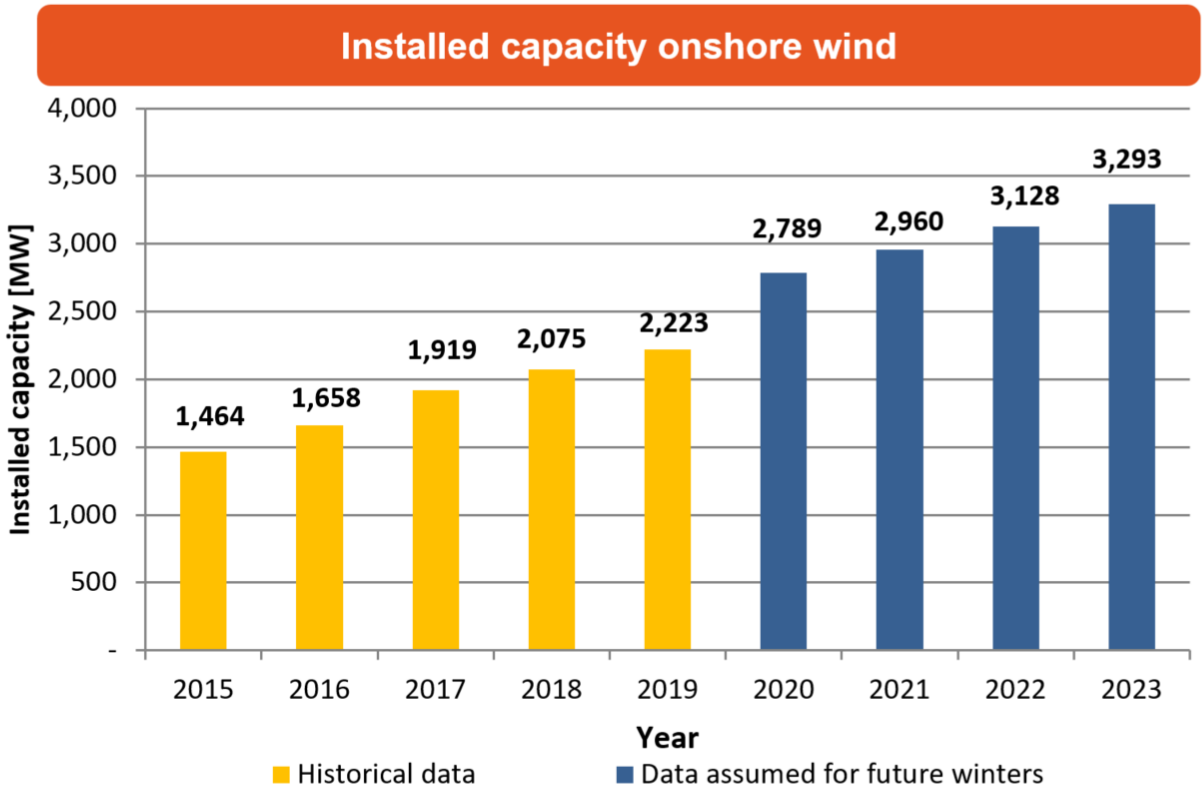


Figure 3.2

3.1.1.3 Wind offshore

The Belgian government awarded domain concessions for the construction and operation of offshore wind generation facilities to nine wind farms (see Figure 3.3). With the completion of the Modular Offshore Grid (MOG) in May 2020 and the go-live of SeaMade in late 2020 a capacity of 2253 MW from offshore wind will be available in the first winter covered here (2021-22). Figure 3.2 shows the historical increase in installed capacity of offshore wind and the forecast installed capacity taken into account for the purposes of this analysis, which is a best estimate based on the latest information available to Elia.

Future plans for offshore wind in Belgium

Besides the current offshore concessions (up to 2.2 GW), Belgium has plans to allocate concessions for the construction of additional wind farms in the North Sea providing a potential wind capacity of 1.75 to 2.1 GW with the goal of achieving 4 GW of installed offshore wind capacity by 2030. The first wind farms are expected to be on-stream no earlier than 2026. Hence, they do not have an impact on the strategic reserve volume assessment for the next three winters.

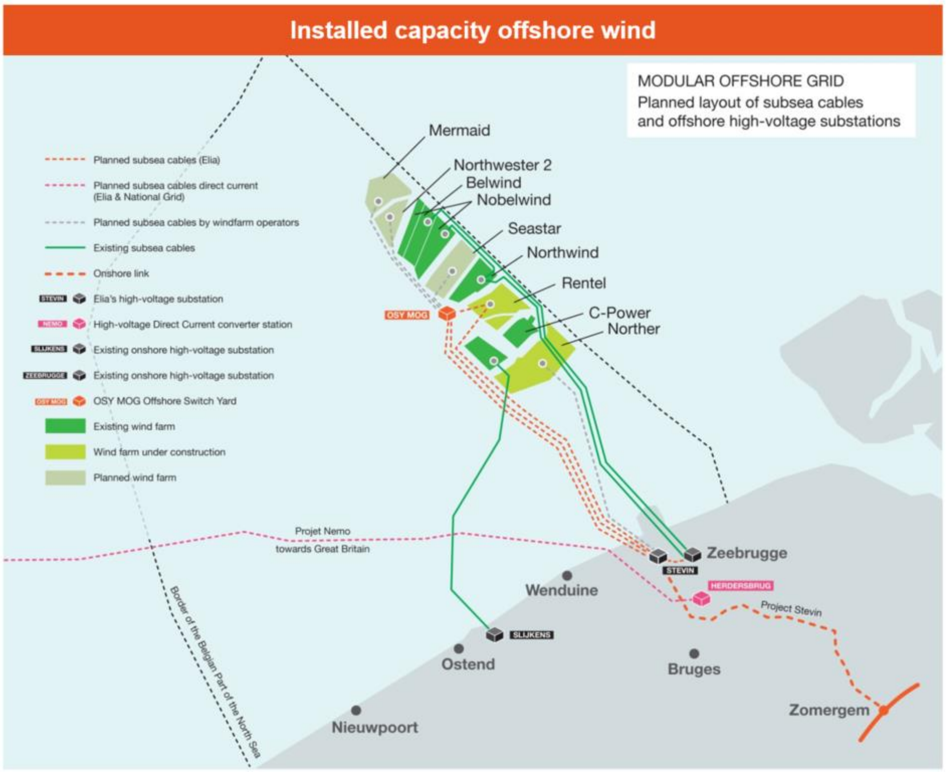


Figure 3.3

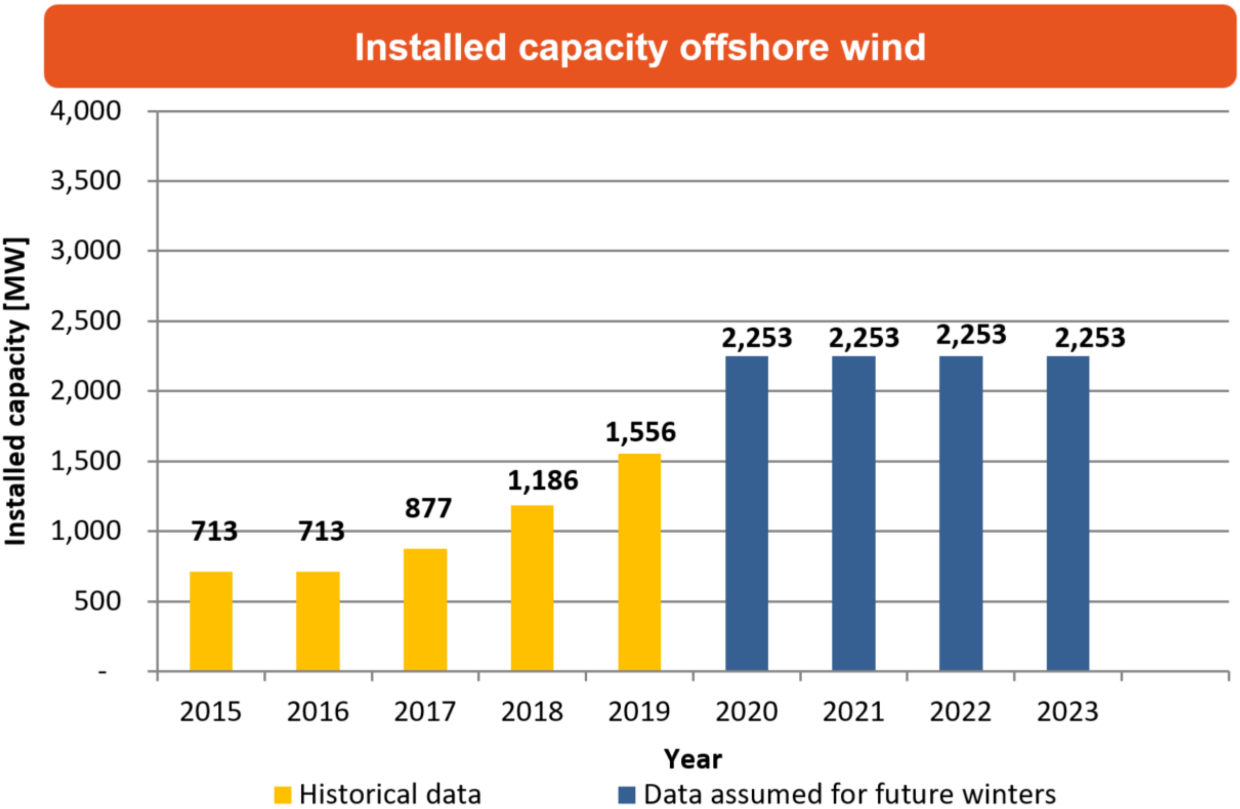
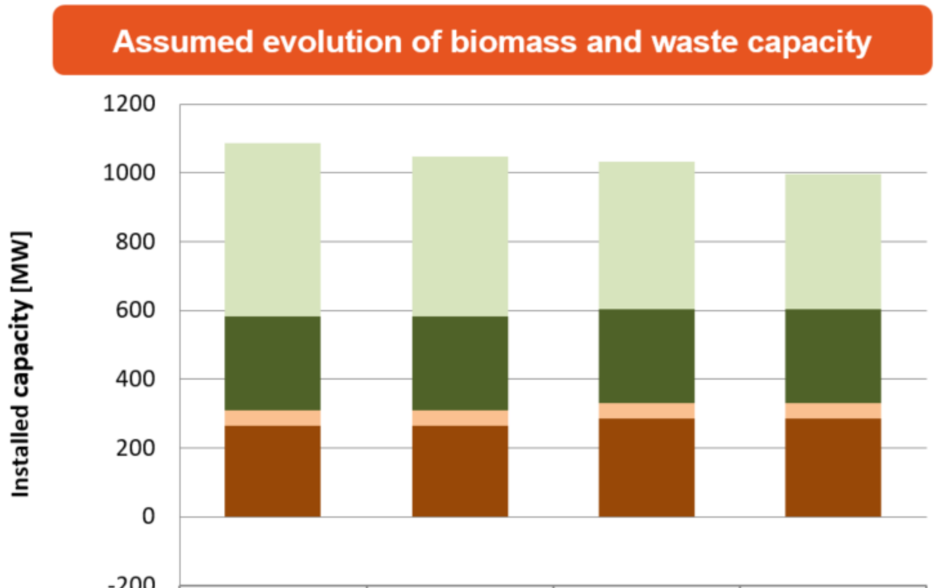


Figure 3.4

3.1.2 Biomass, waste and CHP facilities

This section elaborates on the installed capacity of biomass, waste and combined heat and power (CHP) production facilities in Belgium. Elia maintains a database of centralised and decentralised generation units, which is updated on a monthly basis following exchanges with DSOs and direct clients of Elia. The database includes units covered by a CIPU[17] contract as well as units not covered by such a contract.

Owners of units covered by a CIPU contract must notify Elia about these units' availability and provide Elia with both long-term (one-year) and short-term (one-day) availability forecasts. In general, units not covered by CIPU contracts have a lower installed capacity. It has been agreed with DSOs that at least all units with an installed capacity of more than 0.4 MW must be reported to Elia for inclusion in the database. In practice, many units with an installed capacity of less than 0.4 MW are also reported, either individually or on an aggregated basis. The database contains information concerning units that are **in service** as well as on projects that are currently **under development.** The information available in the Elia database is combined with projected growth rates provided by the FPS Economy and NECP projections to forecast the installed generation capacity for the next three winters. This additional generation capacity is modelled as units not subject to a CIPU contract. With the decommissioning of the AWIRS 4 biomass plant in 01/09/2020 the total capacity of individually modelled biomass plants is forecasted to remain constant at 273 MW over all simulated winters. Based on Elia's generation database, the only notable evolution in waste capacity is the commissioning of the E-Wood powerplant, which will be added to the fleet in the simulations for the winters 2022-23 and 2023-24.

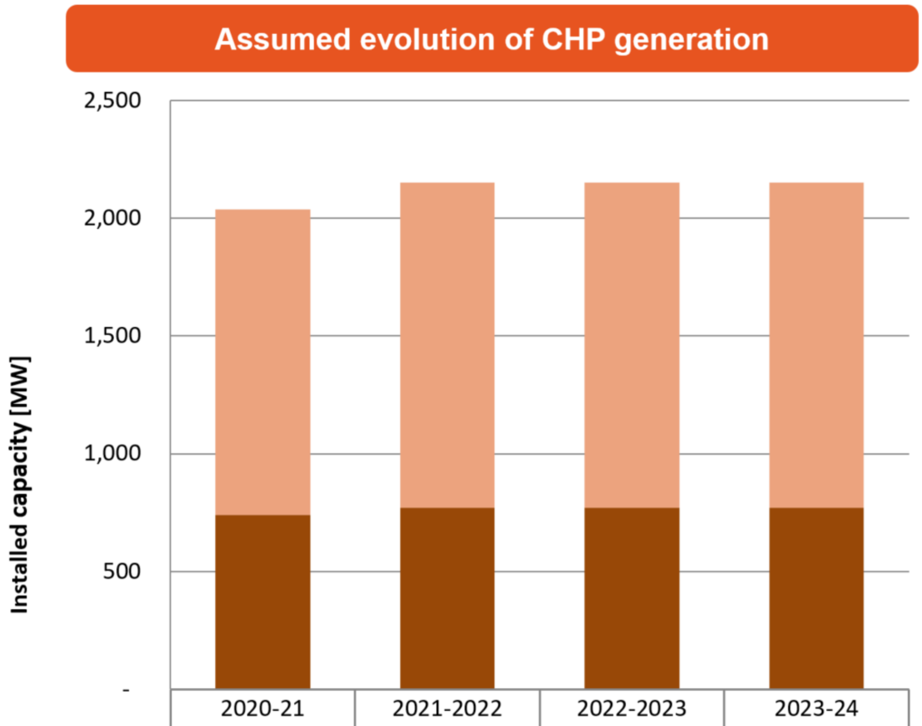


	2020-21	2021-2022	2022-2023	2023-24
Growth Biomass non-CIPU		-7.7%	-8.0%	-8.5%
Biomass non-CIPU	503	465	427	391
Biomass CIPU	273	273	273	273
Waste non-CIPU	46	46	46	46
Waste CIPU	264	264	286	286

Figure 3.5

[17] CIPU: Contract for the Injection of Production Units. The signatory of the CIPU contract is the single point of contact at Elia for aspects relating to the management of the generation unit injecting electricity into the high-voltage grid. The CIPU contract serves as the basis for the provision of other reserve power, and the activation by Elia of such reserve power.

Similarly, it was decided to determine installed **CHP** capacity based on the information in the Elia generation unit database. Only projects communicated to Elia that are in a sufficiently mature phase of development were included in this analysis. Figure 3.5 shows the assumed increase in installed capacity from CHP generation.



	2020-21	2021-2022	2022-2023	2023-24
Gas and other CHP non-CIPU	1297	1379	1379	1379
Gas CHP CIPU	739	771	771	771

Figure 3.6

3.1.3 Thermal generation under a CIPU contract

This section details Belgian thermal generation units covered by a CIPU contract. Biomass, waste, and CHP generation units covered by such contracts are discussed in section 3.1.3.1. Figure 3.7 below presents the installed capacity from thermal units covered by a CIPU contract. Since such units are modelled individually, outages of individual units are taken into account. The way in which thermal availability is included in the simulation is described in section 8.1 (appendix).

3.1.3.1 Installed capacity from thermal generation by units covered by a CIPU contract

The installed capacity of Belgian thermal generation by units covered by a CIPU contract is consolidated by Elia and the FPS Economy based on information submitted by producers to the federal Minister for energy, the FPS Economy, CREG and Elia, as stipulated in the Electricity Act. These parties cannot be held accountable for actually realizing the hypothetical volumes, as this is the producers' responsibility. Figure 3.7 shows the assumed capacity for the thermal generation units covered by a CIPU contract.

Section 3.1.2 already provided equivalent details for Belgian **biomass, waste and CHP** units covered by a CIPU contract.

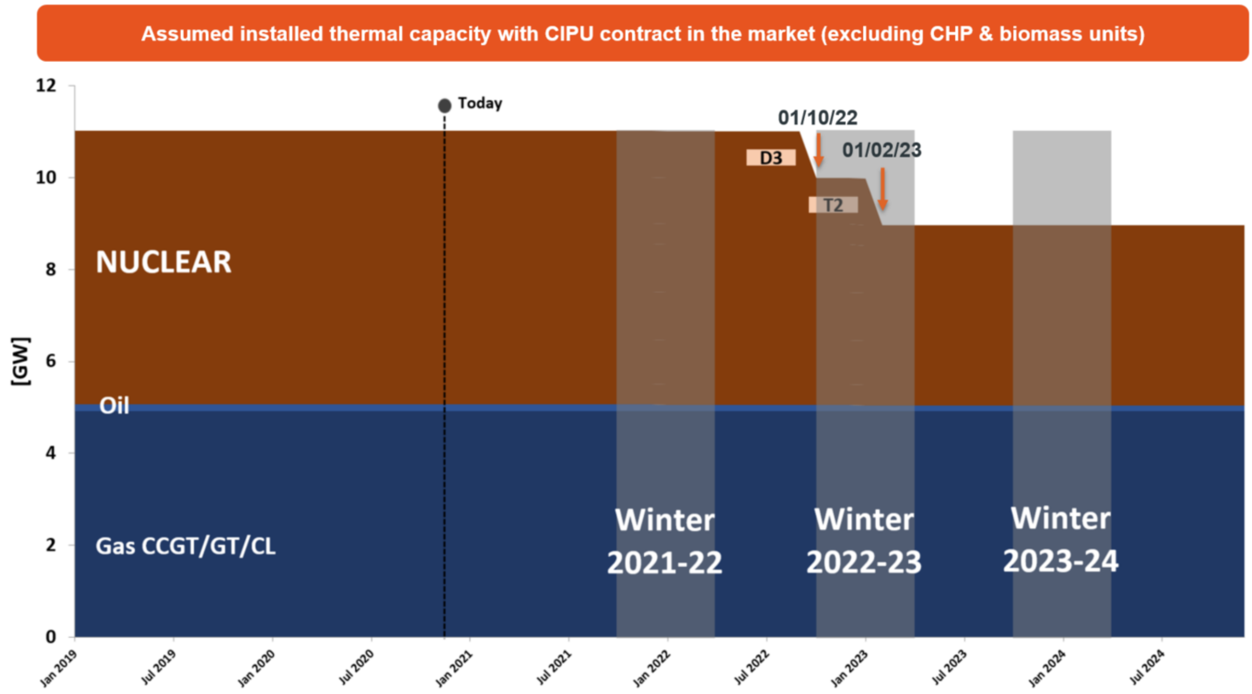


Figure 3.7

The hypothesis used in this analysis regarding installed capacity from **nuclear** generation is in line with the law governing the nuclear phase-out, which has been amended twice:

— In 2013, to extend the working life of the Tihange 1 power plant (installed capacity of 962 MW) by 10 years;
— in June 2015, when the Belgian government decided that the Doel 1 and Doel 2 nuclear power plants (each with an installed capacity of 445 MW) could stay operational for an additional 10 years.

In line with the amended Belgian law on the nuclear phase-out, it is assumed that in the 'base case' all seven nuclear reactors (with a total installed capacity of 5943MW) will remain in service for the first time horizon considered: winter 2021-22. For the second winter considered, 2022-23, the decommissioning of the Belgian nuclear fleet is expected to start according to the timetable defined in the Belgian law: Doel 3 is expected to be decommissioned on 1 October 2022 and Tihange 2 on 1 February 2023. In the last winter under study, 2023-24, no additional nuclear units are decommissioned.

Art.4bis, §1

Legal notice period for production facility closure according to Article 4bis

The article setting the rules for the closure of a production power plant was changed during the course of 2018. Its full version, too long to be copied in this document, can be found on the Belgian ejustice website in Dutch and French [17].

3.1.3.2 Availability of thermal generation covered by a CIPU contract

For all generation units considered in the market, all calculations take account of their scheduled maintenance as announced by their owners in line with the REMIT transparency regulation and of CIPU processes, forced outages and rates of use based on an analysis of their historical unavailabilities. The way the availability of generation units is taken into account in the generation of 'Monte Carlo' years is described in Appendix 8.1.

Belgian thermal generation units covered by a CIPU contract are modelled individually in the ANTARES model. The analysis takes account of two types of unavailability for CIPU generation units:

— **planned unavailability**, usually for maintenance;
— **unplanned unavailability**, usually caused by an unexpected malfunction.

3.1.3.2.1 Planned unavailability

Owners of all generation units with an installed capacity of at least 100 MW are obliged to transparently publish the latest information on the unavailability of units in their fleet via official transparency channels (REMIT), over a three-year time horizon. The assumptions made in this study regarding planned unavailabilities of Belgian generation units are based on the latest information available via the relevant market transparency channels (REMIT).

As the maximum availability of domestic generation during the winter period is crucial for Belgium to maintain its adequacy, Elia urged the owners of the generation units concerned to avoid insofar as possible any planned maintenance of their units during the winter period (for details, see *Method and hypotheses used calculating the optimal maintenance curve* below).

However, the extract of 15 October from the transparency channels, which was used for this study, contained some planned unavailabilities in winter periods. Below is an exhaustive list of those unavailabilities which were taken into account for the winter 2021-22 analysis. No non-nuclear revisions are scheduled in winter.

— DOEL 4 undergoing maintenance from 23/10/2021 until 30/11/2021 (inclusive);
— TIHANGE 3 undergoing maintenance from 21/02/2022 until 31/03/2022 (inclusive);

Planned outages 2021-2022				
Unit	Pmax Available (MW)	Pmax available after outage (MW)	Start outage	End outage (inclusive)
DOEL 1	445	0	22/05/2021	04/07/2021
DOEL 1	445	0	11/06/2022	23/07/2022
DOEL 2	445	0	27/03/2021	09/05/2021
DOEL 2	445	0	02/04/2022	14/05/2022
DOEL 2	445	0	18/06/2022	25/06/2022
DOEL 3	1006	0	28/08/2021	05/10/2021
DOEL 4	1039	0	23/10/2021	30/11/2021
TIHANGE 1N	481	0	18/06/2022	23/07/2022
TIHANGE 1S	481	0	18/06/2022	23/07/2022
TIHANGE 2	1008	0	07/05/2022	10/06/2022
TIHANGE 3	1038	0	21/02/2022	31/03/2022

Based on 15/10/2020 data from REMIT

The following maintenance rounds announced via REMIT will be taken into account for winters 2022-23 and 2023-24:

Planned outages 2022-2023				
Unit	Pmax Available (MW)	Pmax available after outage (MW)	Start outage	End outage (inclusive)
DOEL 1	445	0	27/05/2023	08/07/2023
DOEL 2	445	0	11/02/2023	25/03/2023
DOEL 4	1039	0	08/04/2023	20/05/2023
TIHANGE 1N	481	0	21/10/2023	02/12/2023
TIHANGE 1S	481	0	21/10/2023	02/12/2023
TIHANGE 3	1038	0	19/08/2023	01/10/2023

Based on 15/10/2020 data from REMIT

Planned outages 2023-2024				
Unit	Pmax Available (MW)	Pmax available after outage (MW)	Start outage	End outage (inclusive)
TIHANGE 1N	481	0	21/10/2023	02/12/2023
TIHANGE 1S	481	0	21/10/2023	02/12/2023
TIHANGE 3	1038	0	19/08/2023	01/10/2023

Based on 15/10/2020 data from REMIT

3.1.3.2.2 Unplanned unavailability

Belgian thermal generation units covered by a CIPU contract are modelled individually in the ANTARES model by taking into account planned unavailability (usually maintenance) and unplanned unavailability (usually caused by an unexpected malfunction). An analysis was carried out for each generation type (CCGT, gas turbine, turbojet, etc.), based on historical unplanned unavailability for the period 2010-2019 and using the availability for generation units nominated in the day-ahead market. The available public data from ENTSO-E Transparency [16] were used for historical years when available (i.e. only for 2015-2019 period). The results are shown in Figure 3.8.

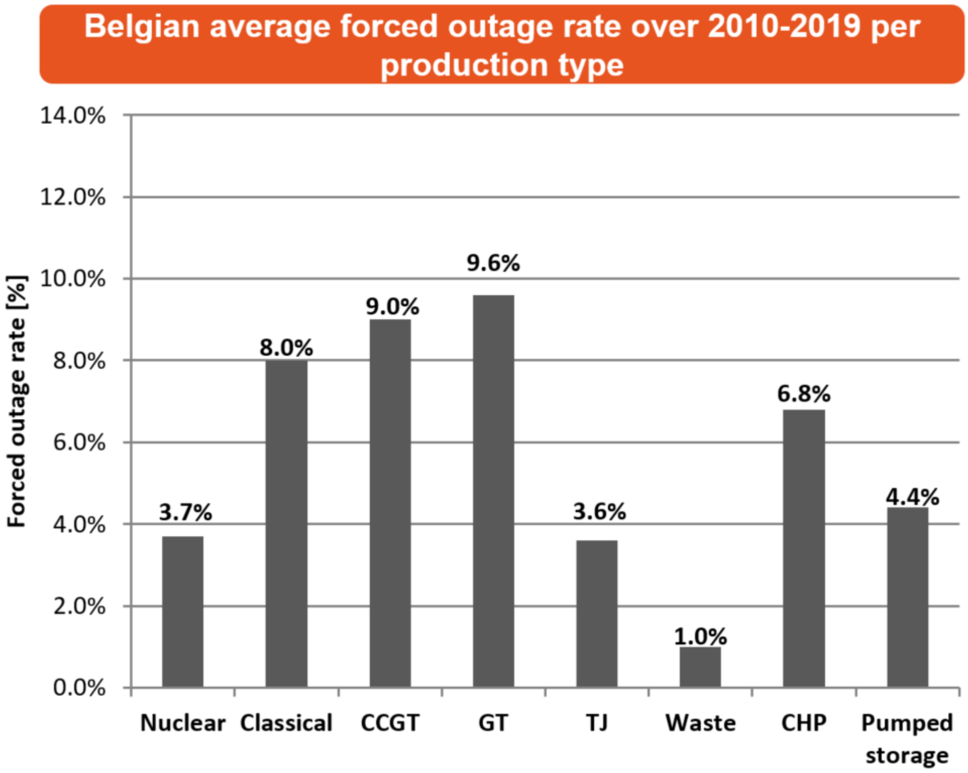


Figure 3.8

Method and hypotheses used for calculating of the optimal maintenance curve

Every year, on a fixed date, the access responsible parties (ARPs) submit a proposed maintenance schedule for their generation units to the TSO. If a risk of a one-off or structural shortage is identified, the TSO has the option of modifying these maintenance schedules:

- The TSO determines the **optimal maintenance curve** for Belgian generation units on an annual basis. For each week of a full calendar year, this curve indicates the total generation capacity that can undergo maintenance. The curve is based on a **probabilistic analysis**, taking account of the following adequacy criterion: the 95th percentile of the remaining available capacity that can undergo maintenance, calculated on an hourly basis. Elia uses the **same type of model and the same hypotheses** to determine the required strategic reserve volume, but modified to cover a complete calendar year.

By way of illustration, Figure 3.9 shows the result of the aforementioned exercise for 2021. The orange area shows the optimal maintenance curve, with the solid line indicating current scheduled maintenance. Since Elia strives to avoid overhauling power plants during the winter, no maintenance capacity is available in wintertime.

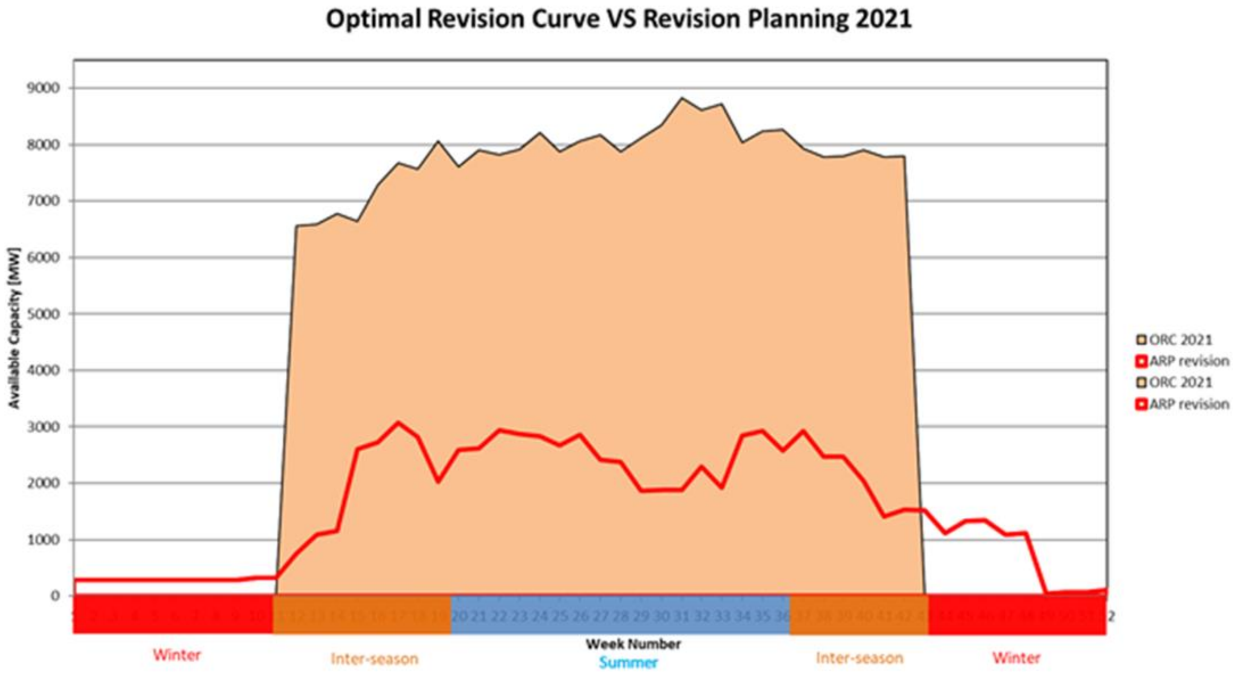


Figure 3.9

3.1.4 Hydroelectric power stations

The Belgian electricity system includes two types of hydroelectric power station:

— pumped-storage units;
— run-of-river units.

Belgium has 10 **pumped-storage** units: six at Coo and four at Plate Taille. The total installed turbine capacity is 1,224 MW, with a combined storage capacity of approximately 5,800 MWh. Pumped-storage units are typically also used to provide ancillary services. Accordingly, specifically to account for the provision of 'black start' services, the total storage capacity available for economic dispatch in this analysis is decreased by 500 MWh, reducing the available storage capacity available for economic dispatching to 5,300 MWh. In the ANTARES model, the Belgian pumped-storage units are modelled individually, enabling planned and forced outages of these units to be taken into account. The model determines the units' dispatch in a daily cycle, taking account of the hourly electricity price (optimal economic dispatch, see section 8.1.2 (appendix)). When the model encounters periods of structural supply shortage, energy prices approach the price cap and the pumped-storage facilities will generate electricity, alleviating the shortage. If the supply shortage lasts longer, the model will dispatch the pumped-storage facilities to shave off the peaks of ENS.

Belgium's **run-of-river** power stations have a combined installed capacity of **117 MW**. According to the information available to Elia and following NECP projections, a small increase in this capacity is expected, resulting in an installed capacity of **129 MW** by the end of 2023. Run-of-river power stations are taken into account in the model based on monthly profiles for the past 34 winters.

3.1.5 Balancing reserves

Article 8, §1 of the Electricity Act stipulates that Elia is obliged to contract ancillary services to ensure a secure, reliable and efficient electricity grid. These ancillary services, also called balancing reserves, are agreements with certain producers and consumers to increase or decrease production on demand at certain sites when required. Elia can use these reserves to restore the balance between generation and consumption when a real-time imbalance occurs. Such imbalances can be caused, among other things, by the unforeseen loss of a generation unit or forecasting errors in renewable production.

Since balancing reserves have to be available to restore deviations independently of the strategic reserve, the simulations take account of the volume of generation capacity contracted for frequency containment reserves (FCRs) and frequency restoration reserves (FRRs) as reductions in available capacity to cope with adequacy issues. This approach is in-line with the current MAF methodology.

FCR – Frequency containment reserve (aka 'primary reserve'):

The objective of primary frequency control is to maintain the balance between generation and consumption within Europe's interconnected high-voltage system. This frequency containment reserve is defined by ENTSO-E for the European synchronous area. For future winters, new technologies, such as battery storage plants, are expected to entirely take over the role of FCR providers from thermal power plants. Therefore the volume provided by thermal generation units for FCR is foreseen to be 0 MW.

aFRR – Automatic frequency restoration reserve (aka 'secondary reserve'):

For winter 2021-22, it is assumed that 150 MW will be provided by Belgian generation units. Note that since September 2020, afRR can be provided by all types of technologies.

mFRR – Manual frequency restoration reserve (aka 'tertiary reserve'):

Tertiary reserve products can be provided either on demand or by generation. The volume reserved for Belgian generation units in this study is 406 MW for winter 2021-22.

For information purposes, Figure 3.10 shows the balancing reserves considered to be provided by Belgian generation units in this study, listed per type of reserve. More information about these types of reserve can be found on Elia's website [18].

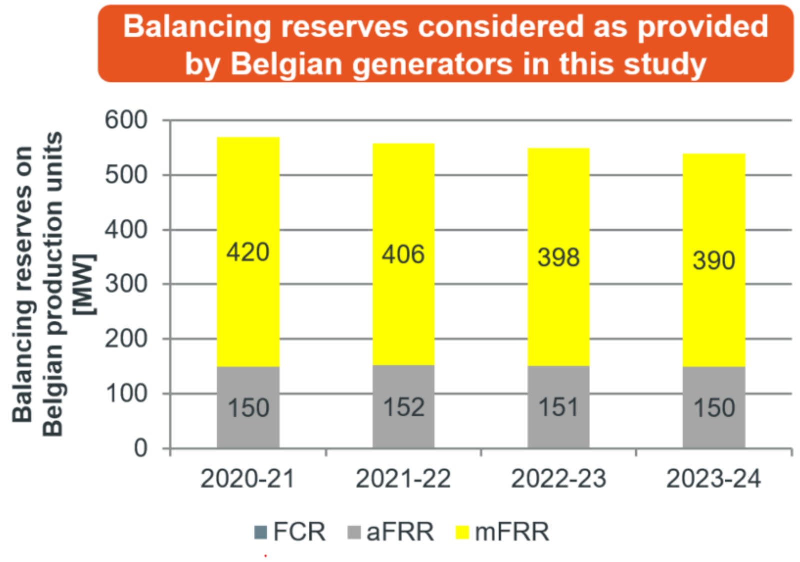


Figure 3.10

3.2 Electricity consumption in Belgium

Modelling electricity consumption consists of three steps (see). This section outlines the assumptions taken for Belgium during each of these steps.

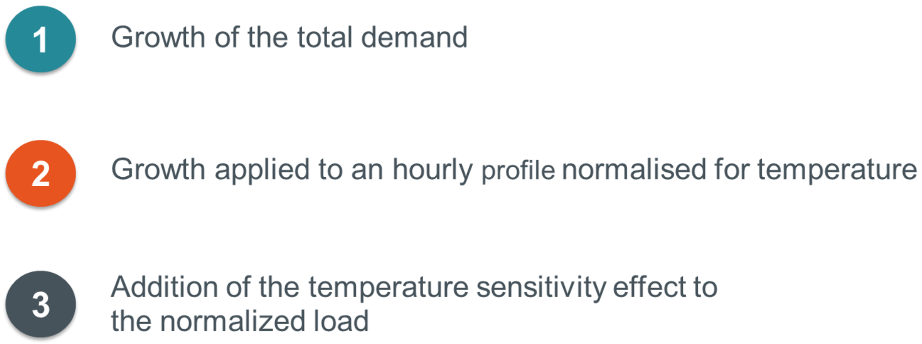


Figure 3.11

What is total electrical consumption (also referred to as 'total load')?

Total electrical consumption takes account of all loads on the Elia grid and distribution system (including losses). Given the lack of quarter-hourly measurements for distribution systems, this load is estimated by combining calculations, measurements and extrapolations.

What are the differences compared with Elia's consumption (also referred to as 'Elia grid load')?

The Elia grid load is a calculation based on injections of electrical energy into Elia grid that incorporates the measured net generation of (local) power stations that inject power into the grid at a voltage of at least 30 kV and the balance of imports and exports. Generation facilities that are connected to distribution systems at voltages under 30 kV are only included if net injection into the Elia grid is measured. The energy needed to pump water into the storage tanks of the pumped-storage power stations connected to the Elia grid is deducted from the total.

Decentralized generation that injects power into the distribution networks at a voltage under 30 kV is not fully included in the Elia grid load. The significance of this segment has steadily increased in recent years. Elia therefore decided to complement its publication with a forecast of Belgium's total electrical load.

Elia's grid comprises networks with voltages of at least 30 kV in Belgium plus the Sotel/Twinerg grid in southern Luxembourg.

How is the consumption of the Sotel/Twinerg in Luxembourg taken into account?

Elia's grid not only includes systems with voltages of at least 30 kV in Belgium, but also the Sotel/Twinerg grid in southern Luxembourg. In this study, Belgium's total load does not include the consumption of the Sotel/Twinerg grid. Instead, this consumption is modelled as a separate load connected to Belgium. For more information, see section 4.6.

What is published on Elia's website?

Two load forecasts are published on Elia's website: the Elia grid load and the total load.

The Elia grid load and total load published there <u>does</u> include the load of the Sotel/Twinerg grid (which is not the case for the total load calculated in this study). For a full explanation, see the website [15].

3.2.1 Growth of Belgium's total electricity consumption

In the framework of this years strategic reserve study, Elia contracted Climact (a consultancy bureau) to create a tool allowing the forecast of the total electricity demand for Belgium. The model that was developed is based on the 'BECalc tool' which was developed by Climact for the FPS Environnement and was further improved in order to take, amongst others, short term economic projections and growing electificiation into account. The methodology is further detailed in a consulted report on the tool [7]. The economic projections from the Federal Planning Bureau published in June 2020 [19] are part of the input parameters for the model. Those economic projections were built taking the expected effects of the COVID pandemic into account. Figure 3.12 gives an overview of last years annual demand (normalized and total) and the forecasts for the next few winters.

		Historical values		Base case normalized total demand	
		Total demand [TWh]	Normalised total demand [TWh]	Growth rate	Forecast [TWh]
historical	**2019**	84.9	85.7	-	-
forecast	**2020**	-	-	-4.3%	82.0
forecast	**2021**	-	-	3.7%	85.0
forecast	**2022**	-	-	2.0%	86.8
forecast	**2023**	-	-	0.9%	87.5

Figure 3.12

The values presented in table form in Figure 3.12 are also plotted as a graph in Figure 3.13.

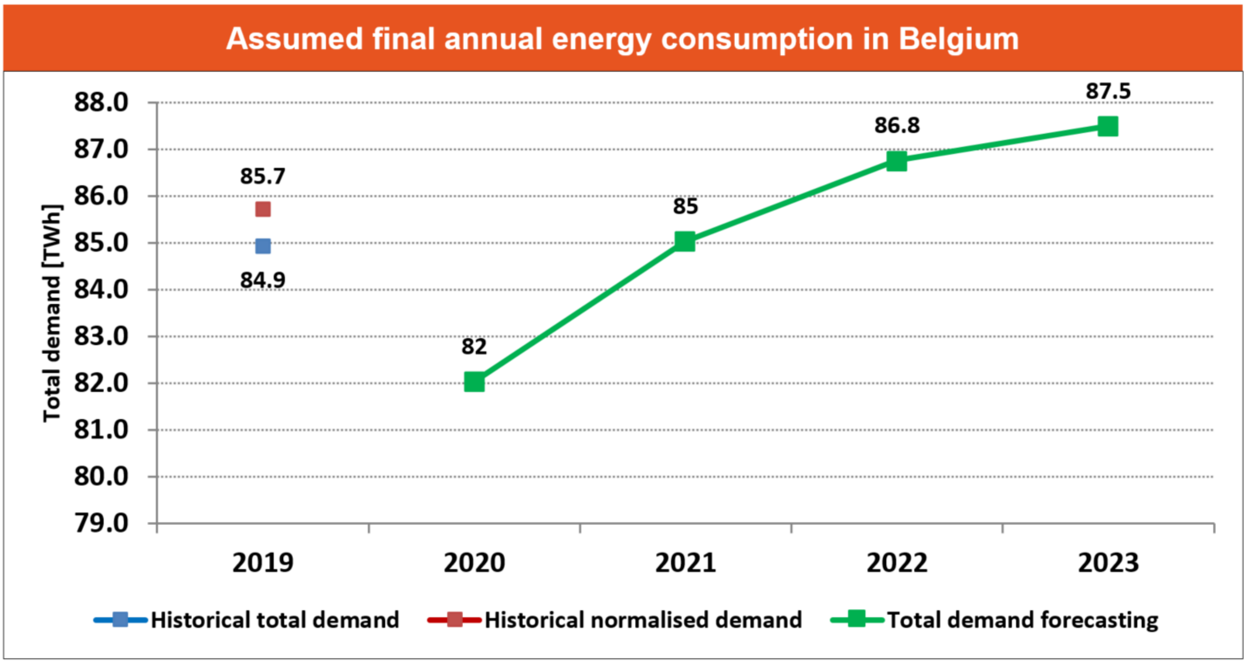


Figure 3.13

3.2.2 Belgian normalised demand profile

The normalised profile used in this study was constructed by a dedicated ENTSO-E working group by combining historical load data with temperature data and information about public holidays. The growth identified in step 1 is applied to this normalised profile to match the total forecast demand normalised for temperature.

This profile does not take account of consumption by pumped-storage units. The model optimises these units' dispatching, thereby adding their load on top of this profile. Section 3.1.4 provides more details about Belgium's pumped-storage units.

Likewise, the profile does not consider the impact of market response, which is modelled separately and optimised based on the cost of electricity generation. Section 3.3 provides more information on the market response in Belgium and the method developed to assess its volume and activation.

3.2.3 Sensitivity of the Belgian load to temperature

The final step entails applying thermosensitivity to the temperature-normalised hourly profile. For each climate year, an hourly profile for consumption is created. Figure 3.14 shows the impact of temperature on the total hourly profile for Belgium for one of the 34 past winters used in this study.

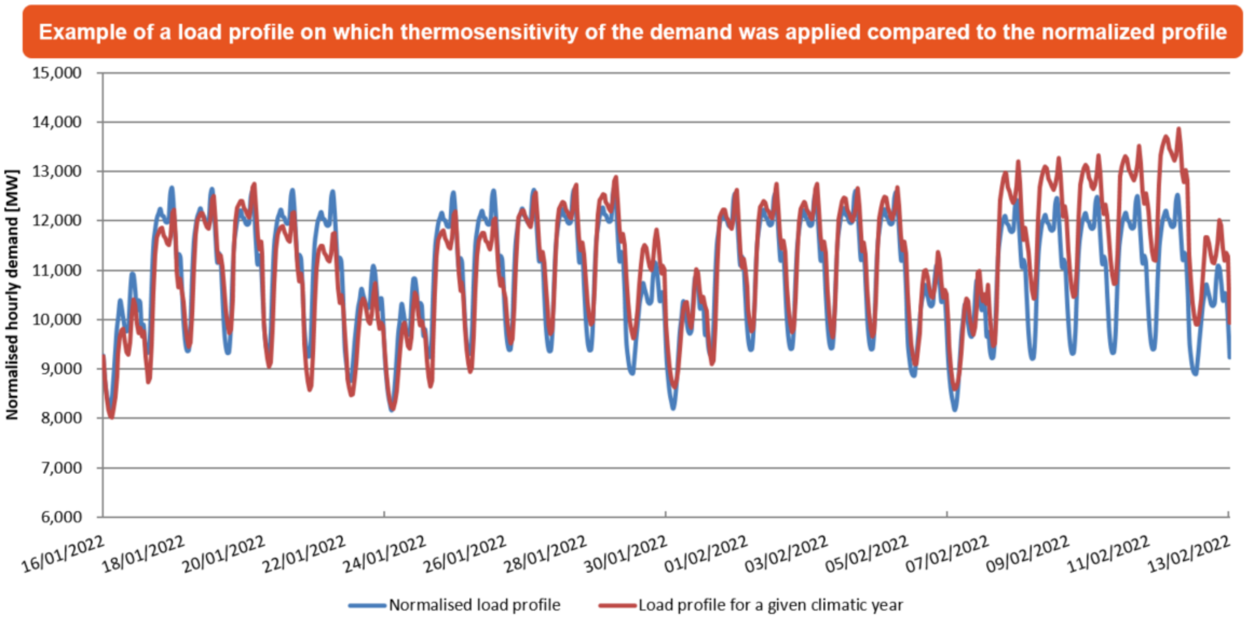


Figure 3.14

The method for taking account of load thermosensitivity was developed in the context of the ENTSO-E MAF study (see section 1.7.3) and relates daily minimal and maximal power to daily temperature (averaged over 24 hours). Furthermore, it is based not on a linear relationship, but on a cubic relationship between temperature and load, since this enables effects like saturation to be systematically captured, while maintaining the same level of accuracy as the previously used linear method. For the purposes of this study, Elia again chose to apply this method, developed in the context of ENTSO-E, for the analysis of winter 2021-22. This choice was made to retain methodological consistency between the determination of strategic reserve volume and the methods developed and used at European level by ENTSO-E.

Forecast peak demand in Belgium for winter 2021-22

Figure 3.15 gives an overview of peak demand after applying the thermosensitivity effect for the 34 winters included in this study to the normalised Belgian profile. The peak demand thus shown is the maximum value observed for a given winter. Although this figure indicates the maximum load observed during the winters covered by the study, it does not show the frequency with which high demand values occurred during those winters.

During the winter period more than one cold spell could be observed, the length of those being a very important parameter for adequacy problems. If high demand is observed for just a few days, it will have a lower impact than if a cold snap lasts a fortnight. Figure 3.15 shows a peak demand of 13.2 GW for the 50th percentile for the winter covered in this study (2021-22) – a probability of 'once every two years'. In extreme cases, peak demand could be even higher, 14.0 GW, as indicated by the 1 in 20 probability (95th percentile, probability of 'once every 20 years').

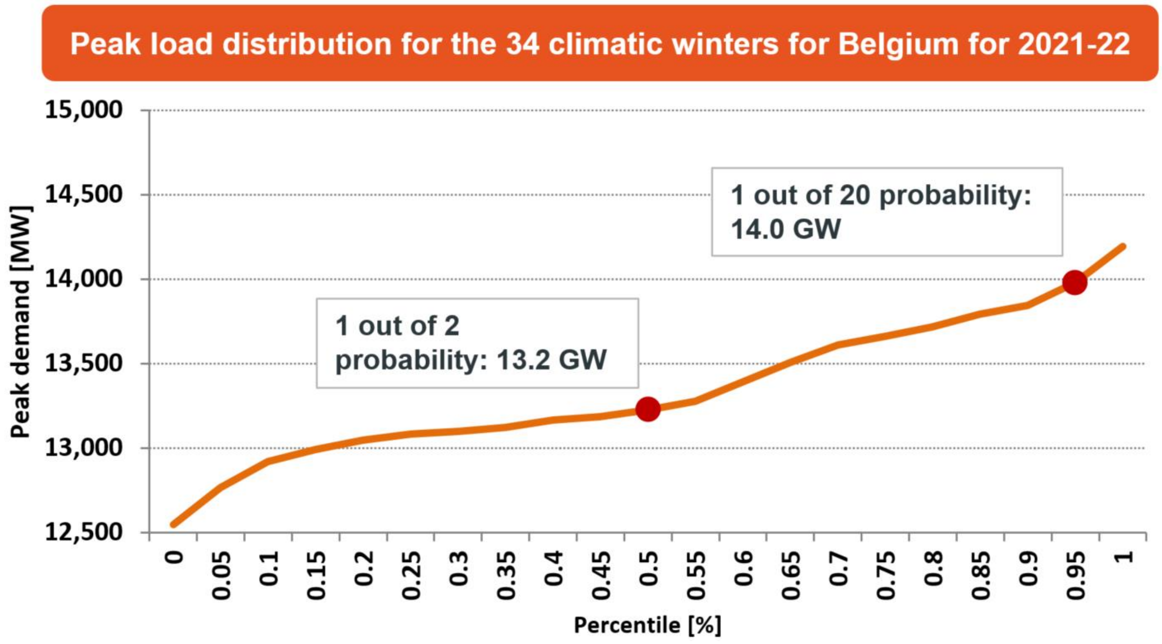


Figure 3.15

Figure 3.16 shows historical peak demand[18] between 2002 and 2019, indicating that this parameter is not constant and is primarily influenced by the temperature. The graphic also shows the probability percentiles for peak demand in winter 2021-22 as used in this analysis.

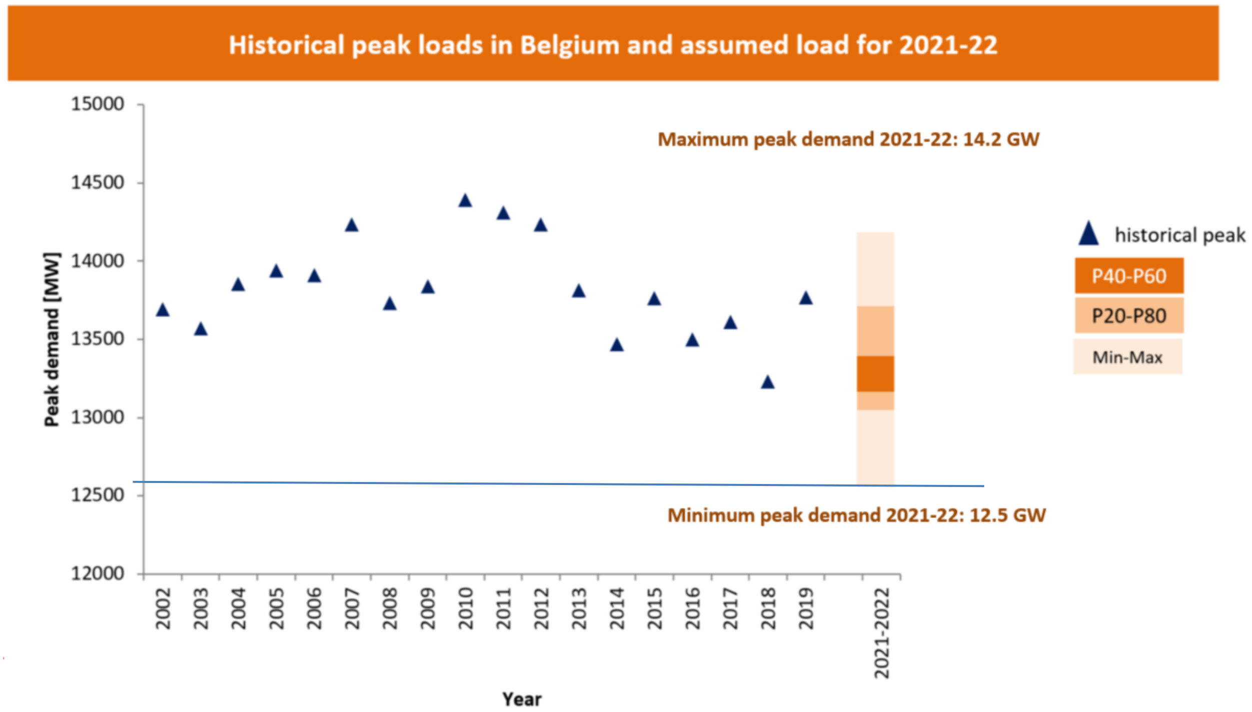


Figure 3.16

[18] Peak demand is an estimate based on measurements and calculations.

Peak demand in winter 2021-22 is assumed to be between 12.5 GW and 14.2 GW, depending on climatic conditions.

3.3 Market Response in Belgium

The results as well as the methodology from the market response study performed by E-Cube are available on the page of the TF iSR [7], [8]. Compared to last year the volume has considerably increased due to the inclusion of Nord Pool, the inclusion of complex bids as well as a higher volulme on EPEX.

The aggregated curves analysis made it possible to estimate market response volumes. These volumes had first to be extracted from EPEX Spot Belgium and Nord Pool day-ahead market aggregated curves to obtain a processable dataset of hourly market response values from 01/01/2014 to 05/04/20. On the demand side, market response volumes can be directly found in the aggregated demand curve by studying the drop in volume when the price rises from €150/MWh to €3,000/MWh (excluding 'at-any-price' bids). In the supply curves, the market response is represented by two volumes: above €150/MWh (high bound) and above €500/MWh (low bound).

The dataset was then refined, firstly by excluding days on which national strikes occurred and treating national public holidays like Sundays. Secondly, 2014 was excluded from the dataset because that year's supply curves reflected a specific bidding behaviour that did not correspond to the reality of today's market. So this refined dataset is more accurate whilst also containing a satisfactory volume of data.

Finally, the extrapolated output was applied to the three next winters (i.e. 2021-22, 2022-23 and 2023-24).

In line with the growth rate applied for the two preceding strategic reserve volume assesment, Elia will proceed with a 7% growth rate.

Assumed market response volume per winter					
Market Response volume [MW]	Measured	Extrapolation			
			Winters under consideration		
	2019-20	**2020-21**	**2021-22**	**2022-23**	**2023-24**
7% growth	1041	1114	1192	1275	1365

Figure 3.17

In this annual assessment of the strategic reserve the decision was made to allocate the capacities over five categories, with the only distinction being the amount of energy that can be allocated per day (expressed in number of hours). This choice was made to ensure consistency with the Adequacy and Flexibility Study [9] published June 2019. The seven categories from the E-Cube study were reduced to five categories for this study by taking the number of activations per week into account and translating the underlying activation duration into equivalent energy per day as shown in Figure 3.18. An activation price between 300 and 2000 €/MWh was used.

For the adequacy assessment model, in practice this means that both the market response in MW and constraints on usage should be taken into account. How this market response is used in the model depends, among other factors, on the price and number of hours of structural shortage. During a structural shortage, when high prices are to be expected, the additional market response will be deployed before proceeding to a situation where the energy supply is not met.

Given these constraints, the additional market response cannot offer a solution at all times of structural shortage, but this model will optimise the deployment of available flexibility, as its output shows. A small analysis on how this affects the impact of market response on adequacy is provided in section 6.1.3.

Assumed market response maximum duration distribution per winter	
Categories & Constraints	**Distribution [%]**
Max use of 1 hour	10
Max use of 2 hours	35
Max use of 4 hours	10
Max use of 8 hours	30
No limit	15

Figure 3.18

3.4 Battery storage in Belgium

A notable increase in battery storage devices, complemented with a growing Belgian fleet of plug in vehicles which could provide vehicle-to-grid services is expected in the coming years. To accurately capture their effect on Belgian adequacy, this year's strategic reserve exercise included the modelling of these devices. The capacities used in the volume assessment can be found in Figure 3.19.

Assumed battery storage capacities and volumes in Belgium						
		2019-20	**2020-21**	**2021-22**	**2022-23**	**2023-24**
Total capacity [MW]		**26**	**26**	**131**	**218**	**357**
Capacity [MW]	Large scale storage	26	26	72	97	171
	Small scale storage	0	0	29	61	96
	Vehicule-to-grid	0	0	30	61	91
Reservoir volume [MWh]	Large scale storage	26	26	72	97	171
	Small scale storage	0	0	87	183	287
	Vehicule-to-grid	0	0	120	240	360

Figure 3.19

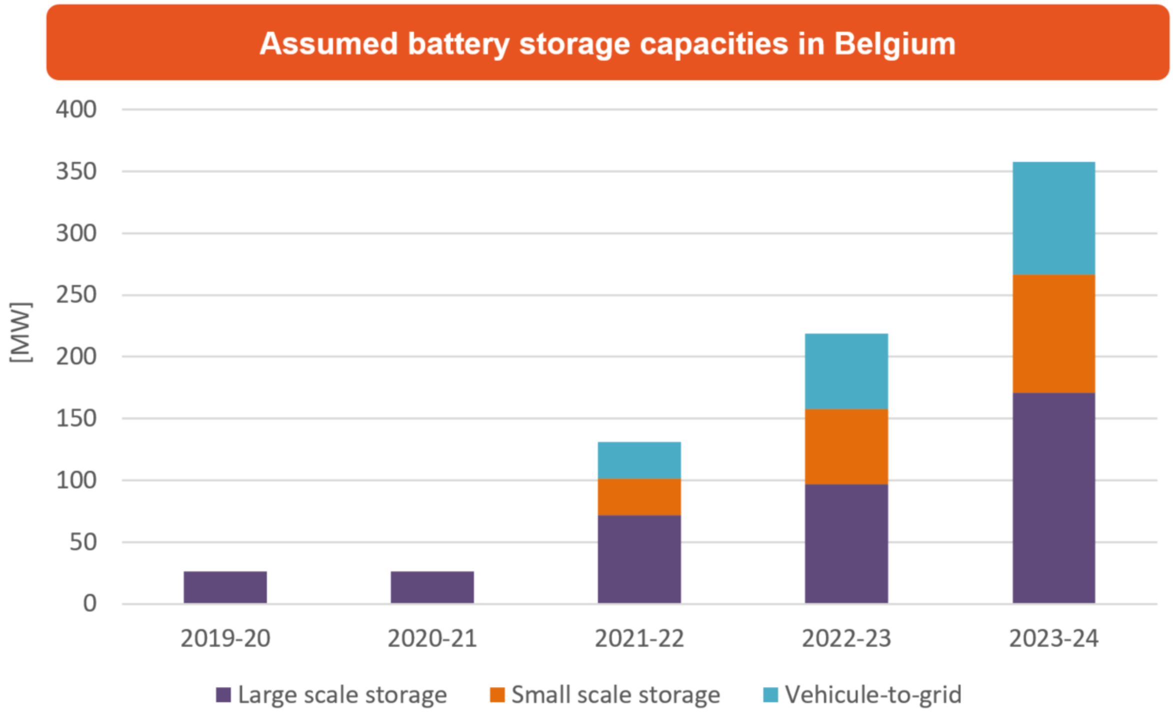


Figure 3.20

3.5 Summary of electricity supply and demand in Belgium

Figure 3.21 summarises the forecast installed generation capacity in Belgium taken into account in the 'base case' scenario for the next three winters and also provides an overview of installed capacities during the previous two winters. Note that this installed capacity does not take into account either forced or scheduled outages or the energy limitations of some technologies.

Installed capacity in the market for Belgium for this study

		Production capacity in winter available in the market [MW]				
		2019-20	*2020-21*	2021-22	2022-23	2023-24
Non RES	Nuclear	5,943	5,943	5,943	4,937	3,929
	CCGT/GT/CL	4,912	4,912	4,912	4,912	4,912
	CHP	1945	2,036	2,150	2,150	2,150
	Turbojets	158	158	158	140	122
Storage	Pumped-storage	1,224	1, 224	1, 224	1, 224	1, 224
	Batteries	26	26	131	218	357
RES	Waste	310	330	330	330	330
	Biomass	794	776	738	700	664
	Run of river hydro	117	117	121	125	129
	Wind onshore	2,223	2,789	2,960	3,128	3,293
	Wind offshore	1,556	2,253	2,253	2,253	2,253
	PV	4,550	5,254	5,817	6,372	6,923
Other	Market response	1,041	1,114	1,192	1,275	1,365
	TOTAL	*24,429*	*25,011*	*26,227*	*26,540*	*26,427*

Figure 3.21

Figure 3.22 was put together by combining the installed generation capacity with the P50 peak demand forecast in Belgium for winter 2021-22. In addition to these capacities, the market response when prices are high should be considered together with its respective activation limits (see section 3.3 for more information). Likewise, this figure does not show potential imports (see chapter 5 for detailed information) and pumped storage and battery capacities. Moreover, it should be noted that comparing the shown P50 peak demand with installed capacity does not provide any indication regarding adequacy. Indeed, the availability of generation and the exact distribution of demand have to be correctly taken into account when analysing Belgium's adequacy.

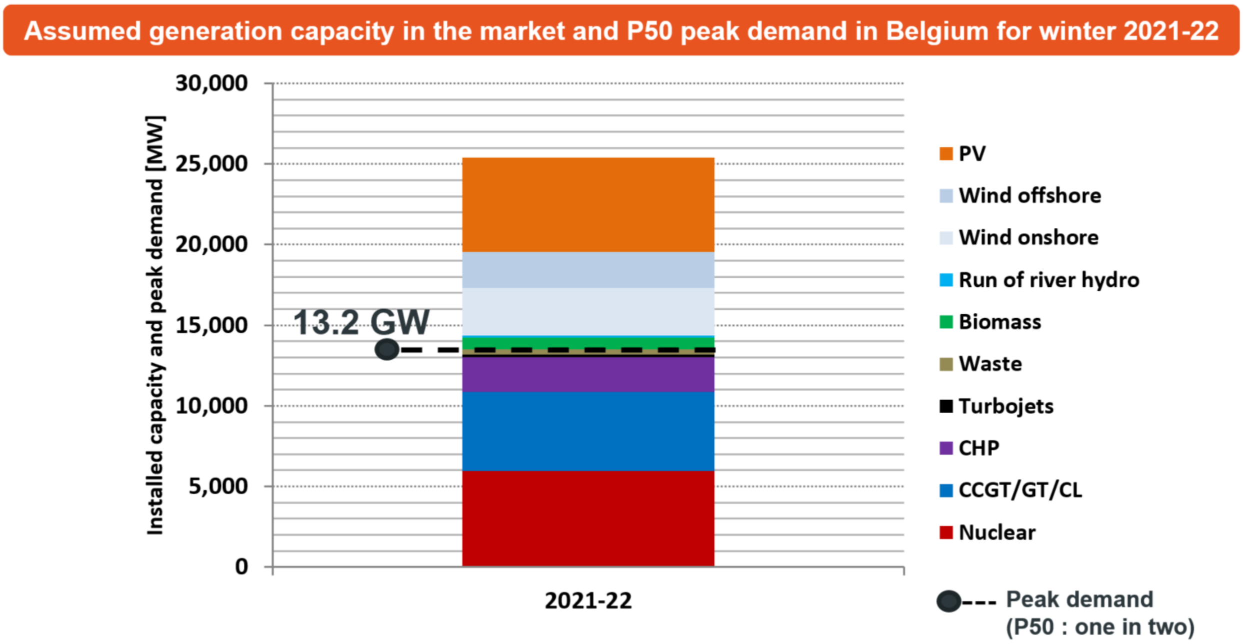


Figure 3.22

4 Assumptions for neighbouring countries

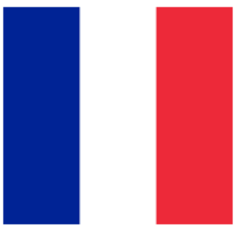
Given the high number of potential energy exchanges between countries, accurate modelling of the situation outside Belgium is crucial for quantifying structural shortages in Belgium. To enable such modelling, data from and assumptions applying to neighbouring countries are collected via bilateral contacts with the respective TSOs. For those non-neighbouring countries included in the model, data were harvested from European joint studies carried out by ENTSO-E or PLEF, or from reports on national adequacy and electricity generation. See section 1.7 for more information on these European and regional studies. The report's main hypotheses are cited for those countries that can exert a strong impact on Belgium's adequacy, namely France, the Netherlands, Germany, Great Britain and Luxembourg.

4.1 Impact of the COVID-19 pandemic on the European electricity consumption

The COVID-19 pandemic and subsequent lockdowns have an important impact on the economic situation and on the electricity consumption. While the future evolution of the pandemic and the expected economic recovery are still unknown, it is hard to ignore that a certain impact should also be taken into account for other countries' consumption. The need for a strategic reserve depends directly on this consumption and as such estimating the impact of the ongoing pandemic on electricity consumption is necessary in performing adequacy assessments. To estimate the impact on the Belgian electricity consumption Elia bases itself on the economical forecasts of Federal Plan Bureau as described in section 3.2. To estimate the impact on other European countries, and given no 'post COVID' data are available, it was assumed to adapt the consumption of other countries based on the same decreases in consumption in Belgian forecasts. **To this end, the pre-COVID forecasted load profiles for other countries were reduced them by the following factors**:

- -2.5% for winter 2021-22;
- -1% for winter 2022-23;
- -0.5% for winter 2023-24.

4.2 France



Nuclear availability is anticipated to be below average levels due to the impact of COVID-19, which prevented the necessary maintenance and refuelling. Flamanville is taken into account as of winter 2023-24 with a partial availability.

Over the past few years, demand in France has stabilized, mainly due to energy efficiency measures and moderate economic growth. This effect combined with the impact of COVID-19 will be reflected in a stable or downward trend.

The assumptions for France are based on the data collected for ENTSO-E's Mid-term Adequacy Forecast (MAF) 2020, along with recent developments or announcements concerning existing and new capacity. The latest adequacy report (*Bilan Prévisionnel* [21]) issued by the French transmission system operator (RTE) also takes those recent developments into account and provides a very detailed view of French adequacy.

Figure 4.1 provides a 'base case' overview of installed capacity in France for winter 2021-22. P50 peak demand is also indicated.

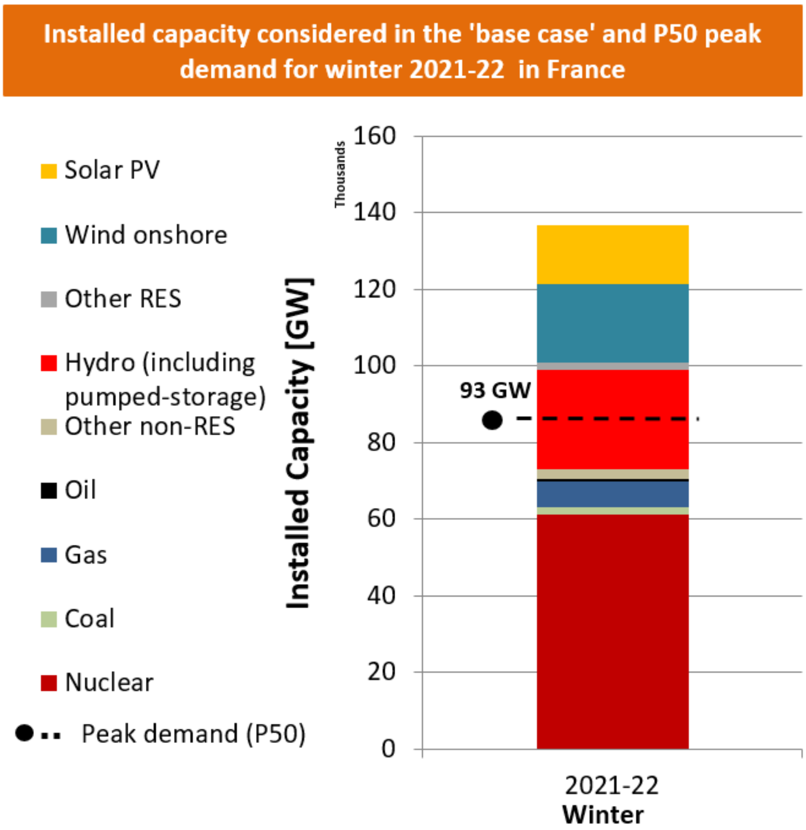


Figure 4.1

4.2.1 Electricity supply in France

4.2.1.1 Thermal capacity (excluding nuclear)

The 'base case' scenario includes the following assumptions about changes in installed thermal capacity (nuclear assumptions are detailed below):

- All CCGT units are expected to be operational for all the winters included in the assessment;
- Landivisau (accounting for 0.4 GW) is assumed to be in service from winter 2021-22 onwards;
- Coal-fired units are continually decreasing and should be completely decommissioned by winter 2022-23 in light of announcements concerning the phase-out of coal;
- Decentralized thermal generation is expected to gradually decrease over the analysed period.

The thermal generation 'base case' (excluding nuclear) is shown in Figure 4.2 below.

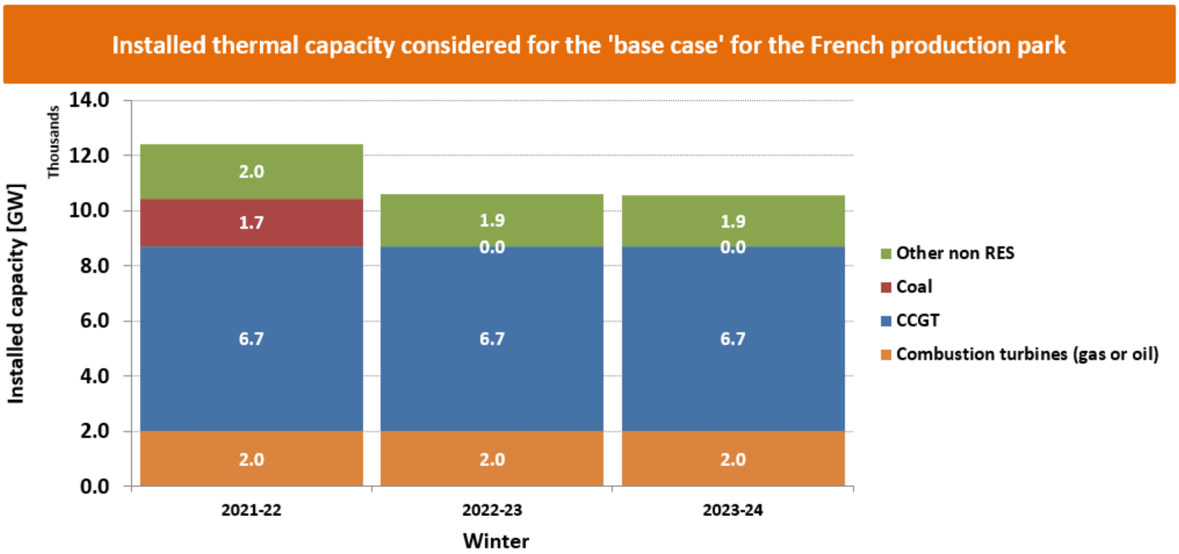


Figure 4.2

4.2.1.2 Nuclear capacity

The French generation fleet is made up nuclear capacity accounting for around 61.3 GW (taking the decommissioning of Fessenheim into account). Furthermore, a new EPR unit is being built in Flamanville. This study assumes that Flamanville will be commissioned in January 2024 for winter 2023-24, and so in line with BP2019, the unit will be considered as having partial availability. Figure 4.3 summarises France's installed nuclear capacity.

The French government has decided to maintain the current nuclear fleet until 2025. The oldest units are reaching 40 years of operation. Each nuclear unit has to undergo a major inspection ten yearly- inspection or also called *visite décennale* (VD) in the Bilan Previsionnel. Given the large number of units in France (57), multiple units are subject to this ten-yearly inspection every year. In June 2019, the Tricastin 1 reactor was the first to embark on its fourth VD. There are always uncertainties surrounding the length of the inspections in view of increased safety measures and any issues detected. The inspections could also lead to lifetime-extension works that can last for several months. Such uncertainties are tackled in the 'High Impact, Low Probability' scenario.

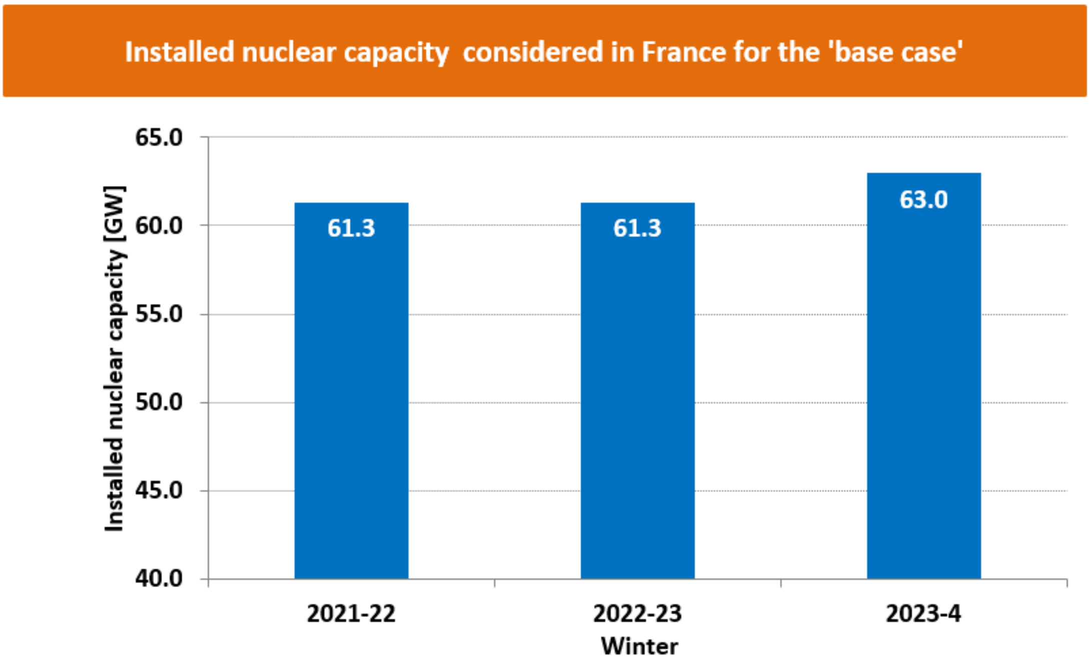


Figure 4.3

Given the significant impact of the French nuclear generation fleet on Belgium's adequacy level, a similar approach to the one adopted for Belgium was taken for the planned unavailabilities of French nuclear generation units. The availabilities of French nuclear units published via official transparency channels (REMIT) by the relevant generation units' owners were taken into account in the models. An extract from the availability data provided by the relevant generation units' owners in France was taken from the transparency channels on 15 October 2020, supplying the data used for this study, as the 'best forecast' of planned unavailability for the nuclear fleet in France. The model also took account of forced outages.

4.2.1.3 Renewable electricity generation

France has a high volume of installed hydro capacity, mainly derived from large reservoirs in the mountains and run-of-river installations. The turbining capacity of Pumped-storage units is also included in the installed capacity given in Figure 4.4 below.

Figure 4.4 also shows a rapid increase in onshore renewables (solar and wind). In addition, the first French offshore wind farm is expected to come online by 2021, with its installed capacity rising to 1.8 GW installed capacity by winter 2023-24.

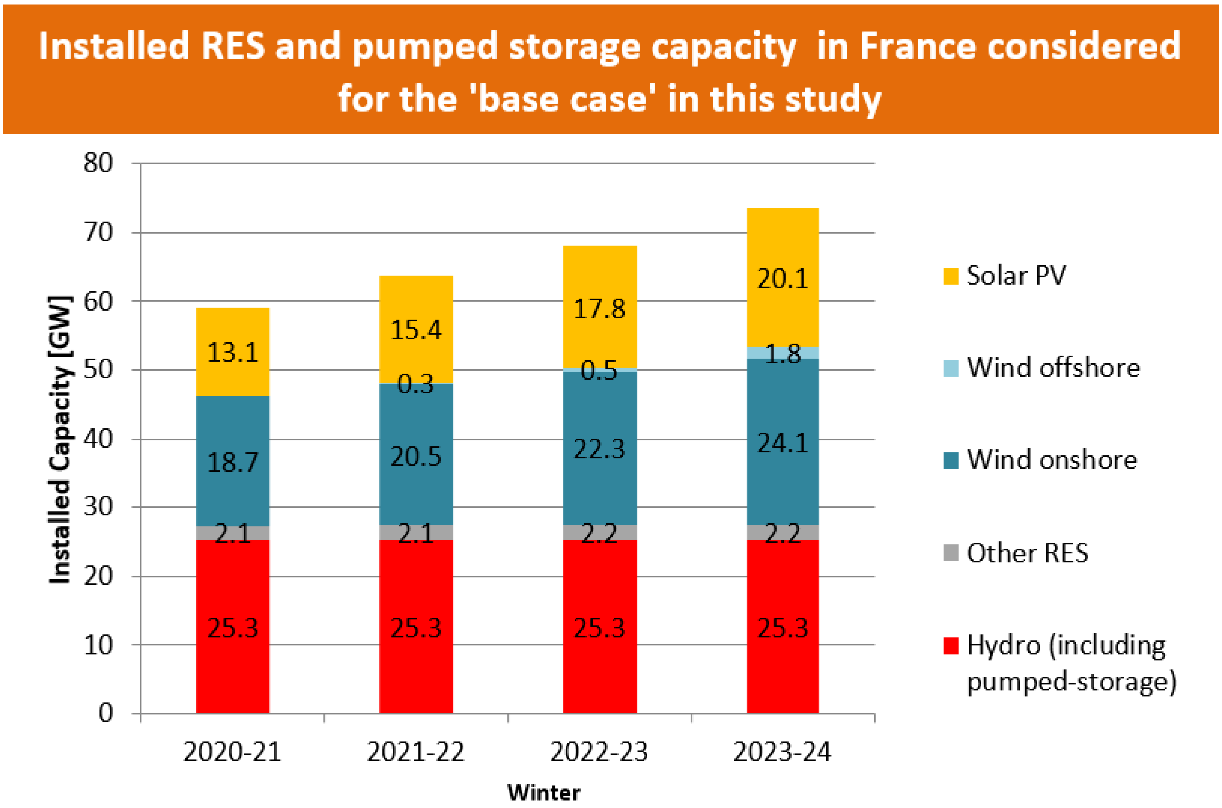


Figure 4.4

4.2.2 Electricity demand in France

Over the past few years, RTE has noted a stabilization in power demand in France, mainly due to energy-efficiency measures and moderate economic growth. These efficiency measures will be further refined in the coming years, so power demand is likely to stabilise or decrease. Peak power demand should follow a similar downward trend.

France's NECP [20] sets out the ambitious objective of halving France's final energy consumption by 2050 (compared with 2012). It provides the legal framework for supporting new tools to optimise energy consumption in that country and sets ambitious targets to reduce multi-energy consumption.

Consumption in France is highly sensitive to temperature differences, accounting for around 2,400 MW/°C, mainly due to the high level of penetration of electrical heating in the country [23] [24] [26].

The market response expected in France mainly corresponds to demand-side management of around 3.7 GW, this corresponds to an increase of 1 GW compared to winter 2020-21.

4.3 The Netherlands

Bilateral communications with the TSO TenneT NL indicates that the Netherlands can ensure its adequacy by relying solely on domestic power generation for winter 2021-22.

Taking into account the expected reduction in operational thermal generation capacity, TenneT NL confirms that the Netherlands might have to rely on imports for its security of supply, but only from around 2025 onwards.

The assumptions made in this study for the Netherlands are collected based on the ENTSO-E PEMMDB database used in the Mid Term Adequacy Forecast (MAF) 2020 report and bilateral communication with Dutch TSO TenneT NL. They are also in line with those used for the Dutch national adequacy study, *Rapport Monitoring Leveringszekerheid 2020* [27] (due to be published in Q1 2021). Figure 4.5 indicates the assumptions used for the Dutch electricity supply and demand for winter 2021-22. Sections 4.3.1 and 4.3.2 elaborate on the situation in the Netherlands regarding supply and demand, respectively.

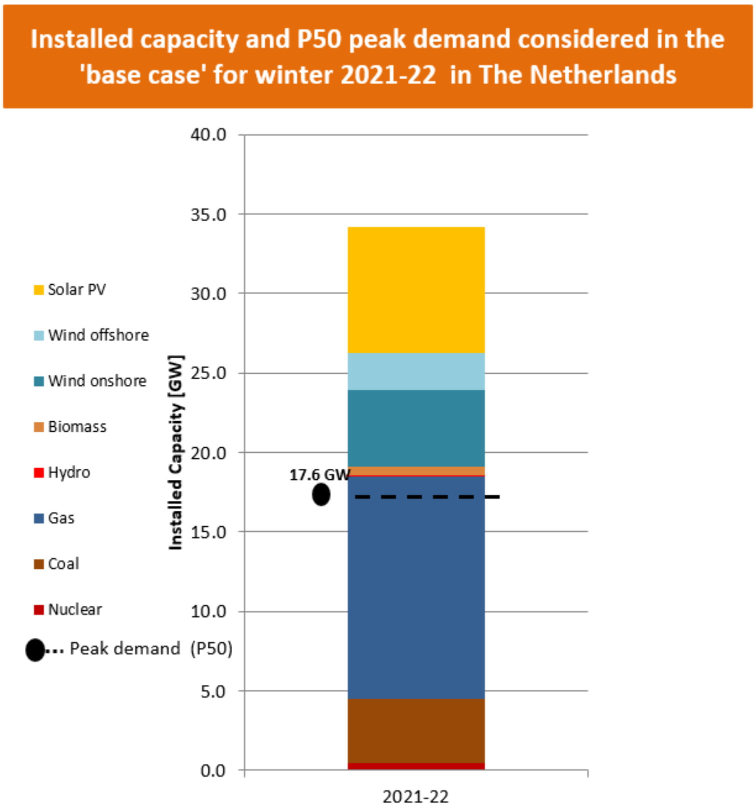


Figure 4.5

4.3.1 Electricity supply in the Netherlands

4.3.1.1 Non-renewable electricity generation

Non-renewable electricity generation in the Netherlands is mainly fuelled by **gas and coal**; see Figure 4.6 for the assumptions made in this study. Sustainable energy policies have led to the shutdown of 3 GW of **coal-fired capacity** over the past 5 years. The Dutch government is pressing ahead with its plans [28] to shut down all other coal-fired power plants by 2030. However, coal-fired power is expected to remain at the current level for the next few years, generating approximately 4.0 GW in the course of each winter under consideration here.

As in other European countries, Dutch **gas-fired** power plants have faced challenging economic conditions in recent years. Several gas-fired plants have been the subject of announcements that they were being temporarily mothballed (i.e. shut down). Some of them only shut down during the summer (summer mothballing), and so are taken into account in this analysis, which only considers the winter. However, more recent years saw more favourable economic conditions, which had a positive impact on the availability of Dutch gas-fired power plants.

The Borssele **nuclear** power plant (with an installed capacity of approximately 0.5 GW) is the Netherlands' only nuclear generation facility and is expected to remain in service throughout the time frame of this study. No new Dutch nuclear power plant projects are expected.

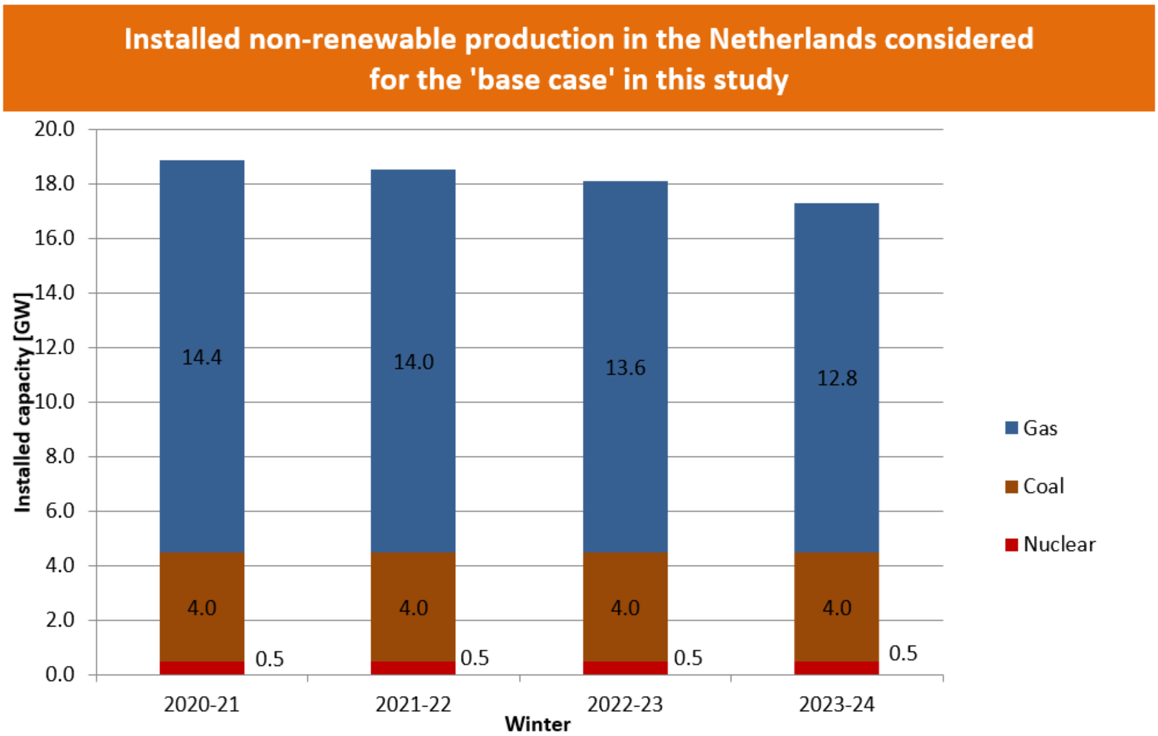


Figure 4.6

4.3.1.2 Renewable electricity generation

On 29 June 2019, the National Climate Agreement (*Nationaal Klimaatakkoord*) was presented by the Dutch government [29]. This agreement builds on previous climate legislation, namely the Energy Agreement for Sustainable Growth (*Energieakkoord voor duurzame groei*).

This study drew on a set of assumptions about renewables installed capacity compiled by Dutch TSO TenneT NL (see Figure 4.7) which provide a best estimate taking into account the National Climate Agreement.

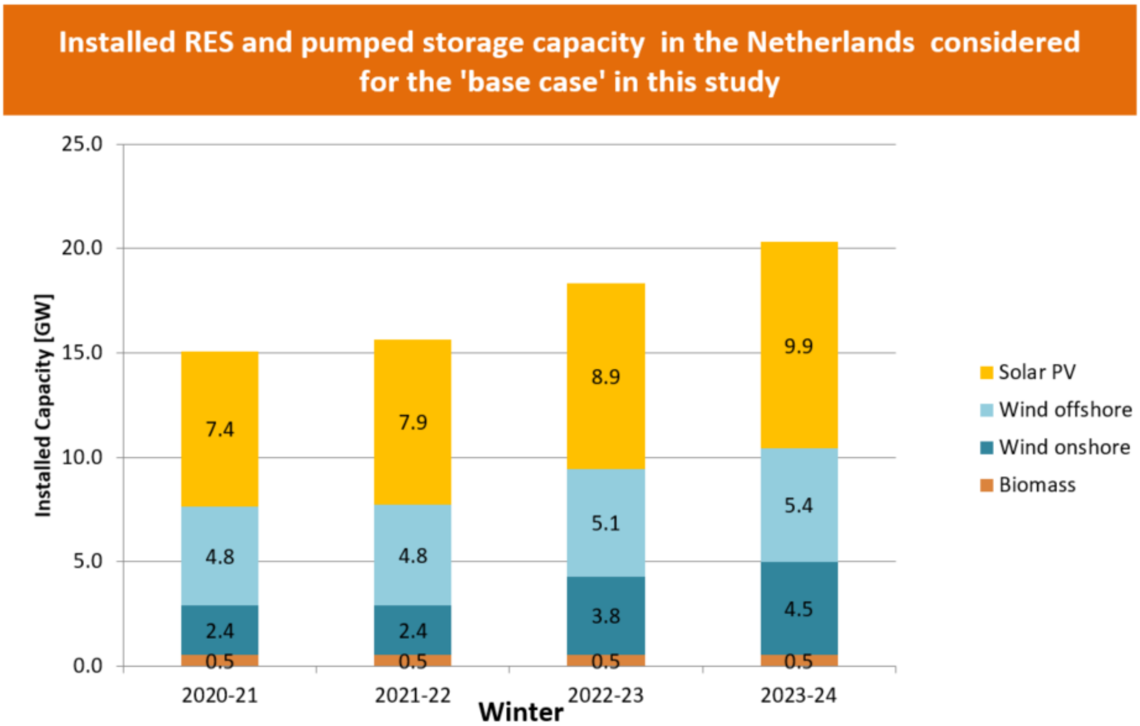


Figure 4.7

4.3.2 Electricity demand in the Netherlands

Assumptions about electricity demand in the Netherlands are in line with the upcoming MAF, as estimated by Dutch TSO TenneT NL. Electricity demand normalized for temperature is expected to remain relatively stable during the period being examined here. In terms of the demand response, a volume of 700 MW was suggested by TenneT for the collection of the data for MAF 2020.

4.4 Germany

Germany has a high levels of RES penetration and also of installed capacity of coal and lignite production. A significant decrease in installed capacity of coal & lignite production is expected in the coming years following the Coal Commission's recommendations (a reduction of 6 GW over the period being examined).

The German nuclear phase-out is on track and all the plants will be decommissioned by the end of 2022.

At the same time, Germany has a comfortable margin to deal with shortages occurring in Belgium and France because of its large volume of potential imports from the north and the east, and its diversified portfolio.

The assumptions about Germany made in this study are based on the 2020 mid-term adequacy forecast (MAF) to be published by the end of the year. Figure 4.8 summarises the assumed supply and demand for winter 2021-22.

Germany's electricity supply is discussed in greater detail in section 4.4.1, while German demand is discussed in section 4.4.2. Finally, Section 4.4.3 discusses the coal phase-out in Germany.

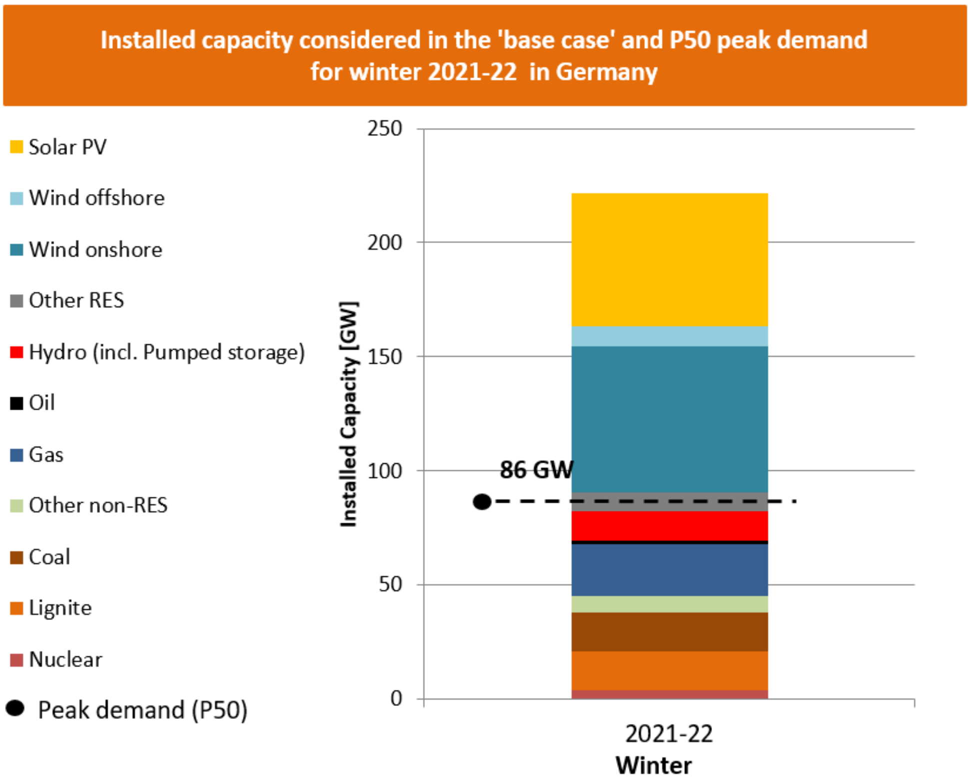


Figure 4.8

4.4.1 Electricity supply in Germany

4.4.1.1 Non-renewable electricity generation

The assumptions made about non-renewable electricity generation in Germany are illustrated in Figure 4.9, which show that the total installed capacity of non-renewable electricity production is expected to drop by approximately 6% over the next four winters.

In 2010, the German government passed legislation on the *Energiewende* (energy transition). One of the cornerstones of its energy transition policy is the phase-out of all German **nuclear** generation by the end of 2022. Of the 17 nuclear reactors in operation at the end of 2010, 10 have already been taken out of service. This amounts to a reduction of nearly 10 GW of installed nuclear capacity already. The next nuclear power plants that are planned to shut down are Grohnde, Gundremmingen C and Brokdorf by the end of 2021 [30]. Finally, Isar, Neckarwestheim and Emsland are to be decommissioned by the end of 2022. Please note that Figure 4.9 shows nuclear units at the 31 December of the relevant year.

Today, almost 20% of the electricity generated in Germany is fuelled by **coal and lignite,** down from 43% in 2015 [31]. A significant drop in the installed capacity of German coal- and lignite-fired production is expected, due partly to environmental policies and also because of government plans to phase out coal-mining subsidies. These plans are detailed in section 4.4.3.

Although a number of **gas-fired** power plants are expected to shut down, a stable trend in gas-fired generation is envisaged in the coming years, since several efficient new plants are expected to be commissioned in the years ahead.

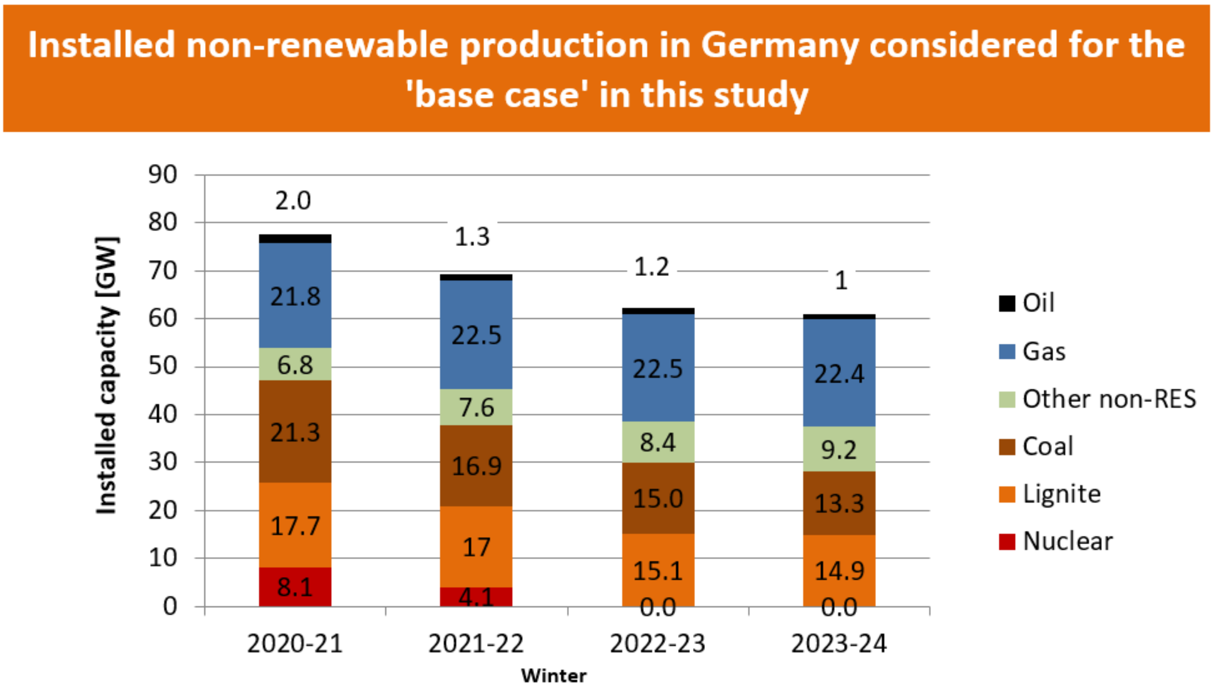


Figure 4.9

4.4.1.2 Renewable electricity generation

Figure 4.10 shows the assumptions made for the installed capacity of German renewable electricity generation. Currently, around 30% of power generated in Germany is derived from renewable sources. This large share of renewables is due to the country's high volume of wind and solar facilities, pushing installed RES and hydro capacity to around 150 GW for winter 2021-22.

The data on renewable generation capacity in Germany are in line with the ENTSO-E's MAF 2020.

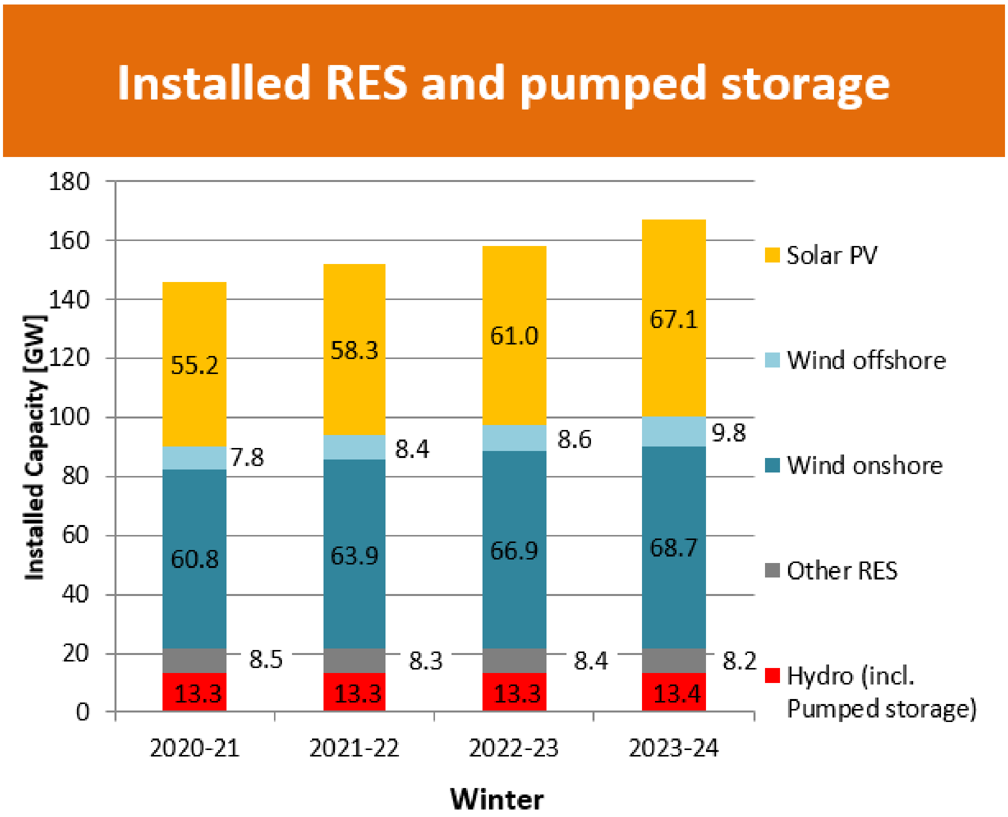


Figure 4.10

4.4.2 Electricity demand in Germany

The assumption made about German demand in this study is in line with what German TSOs communicated to ENTSO-E in the context of the MAF. For 2021-22 a market response volume of about 800 MW has been reported by the German TSOs.

4.4.3 Germany's coal phase-out

The installed capacity on 31 December 2021 for both coal- and lignite-fired power plants will be 34 GW. Following the Coal Commission's recommendations, it is proposed to reduce this capacity to 30 GW by 2022 and 17 GW by 2030 and to shut down all the remaining units by 2038 (or 2035).

In winter 2022-23, there will be an installed capacity of 15 GW each for coal and lignite. The downward trend will then stabilize for the last winter of the period being examined here, with a combined decrease of 2 GW.

4.5 Great Britain

As of winter 2018-19, security of supply in Great Britain is managed through the Capacity Market (CM), based on a recommendation regarding the capacity to secure provided by the British ESO National Grid.

A reduction of the installed thermal capacity is foreseen. More specifically the coal-fired power production is expected to close progressively and to have left the market by 2025. The closure of older gas-fired generation will be partially offset by new built gas-fired power plants.

This section elaborates on the assumptions about the situation in Great Britain used in this study. The assumptions of generation capacity for this country are based on the data communicated by National Grid ESO to ENTSO-E for the European adequacy assessment in the data collection process for MAF 2020 and other European studies released by ENTSO-E. The UK government's 2013 Energy Act [32] introduced the **electricity market reform (EMR)**. Two policies arising from the EMR are the introduction of a capacity market (CM) and the contracts-for-difference (CfD) mechanism. The British capacity market is meant to ensure security of supply in Great Britain, and is discussed in section 4.5.3. The CfD mechanism provides incentives for low-carbon electricity generation capacity.

Section 4.5.1 sets out the assumptions made with regard to the electricity supply for Great Britain. Section 4.5.2 details the demand-related hypotheses used in this analysis.

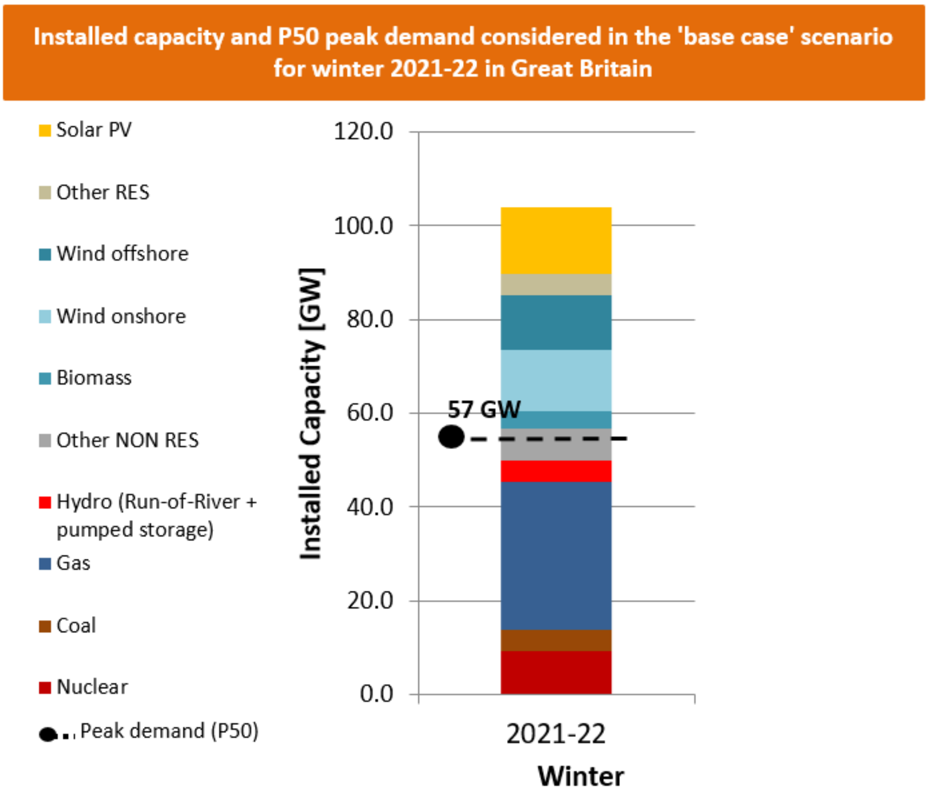


Figure 4.11

4.5.1 Electricity supply in Great Britain

4.5.1.1 Non-renewable electricity generation

Historically, in Great Britain, most electricity has been derived from gas-fired, coal-fired and nuclear generation. However, in 2013, the UK government introduced a carbon price floor (CPF). Initially, this mechanism aimed to bring about a carbon price of £30/tCO_2 by 2020[19], but in 2016 it was modified to limit its impact on British competitiveness [33].

Figure 4.12 shows the assumptions made about Great Britain in terms of non-renewable thermal generation. The CPF has put significant pressure on the profitability of **coal-fired** plants, resulting in a drop of around 6.6 GW in 2019 in installed capacity from coal-fired generation, compared with a 2015 level of 17.3 GW. The installed capacity of coal-fired electricity generation is expected to continue falling during the winters ahead, albeit non linearily, and reach 3.1 GW by winter 2022-23 and to have left the market by 2025.

British **gas-fired** generation units are not expected to face the same profitability issues as in the rest of Europe. The shutdown of older units is being offset with one year delay with the commissioning of new gas power plants. Regarding British nuclear generation units, it is expected that 2 GW of existing capacity (Hinkley Point B and Hunteston), will be decommissioned in early 2023 (i.e. during winter 2022-23). Finally, the most advanced new nuclear project in Great Britain – the EPR Hinkley Point C – will not be on stream in the years under consideration.

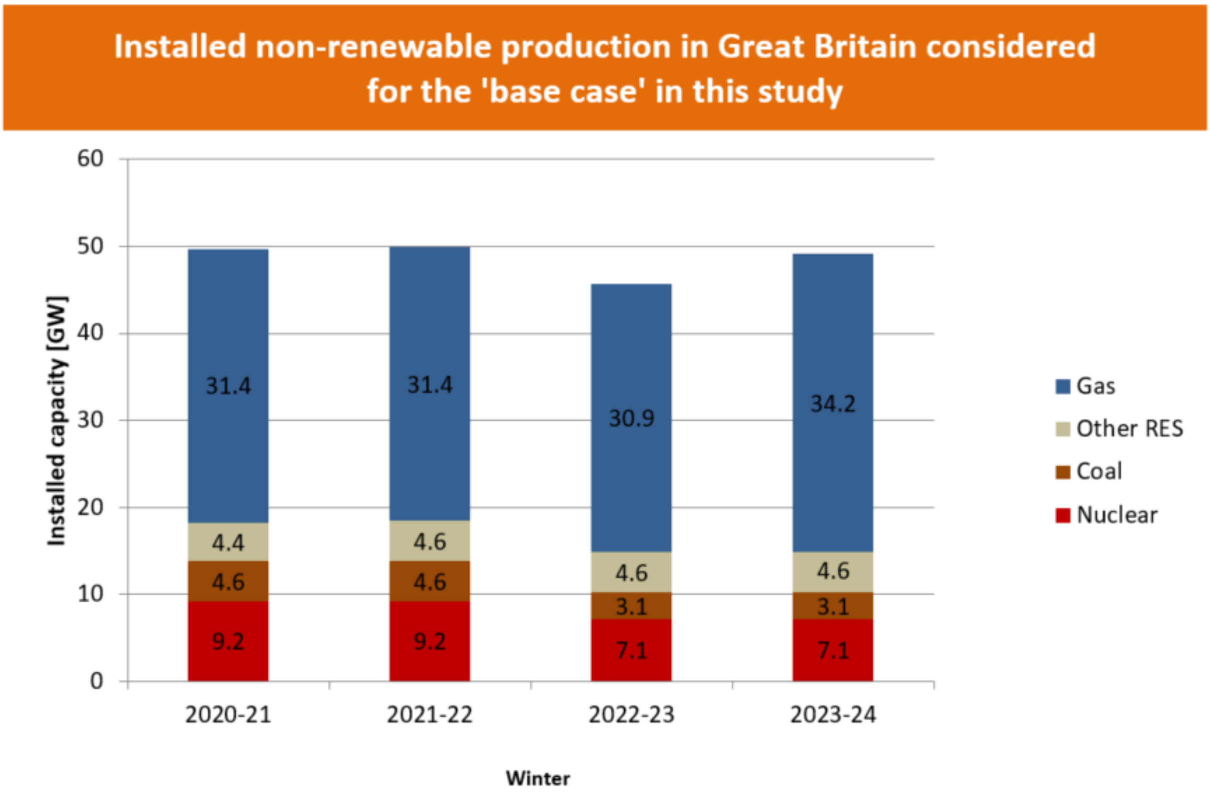


Figure 4.12

[19] A carbon price of £30/tCO_2 by 2020 (in 2009 prices) was initially envisaged.

4.5.1.2 Renewable electricity generation

Figure 4.13 shows the assumptions made in this study regarding renewable electricity generation in Great Britain. The development of renewable generation capacity in Great Britain is incentivised through the contracts-for-difference (CfD) mechanism introduced in the 2013 electricity market reform. The installed capacity of offshore wind is expected to increase by nearly 5 GW by winter 2023-24, vis-à-vis winter 2020-21. For both photovoltaic and onshore wind production limited increases in installed capacity of roughly 4% are expected for the same period. No significant changes are expected in that time for biomass, hydropower and other renewable generation capacity.

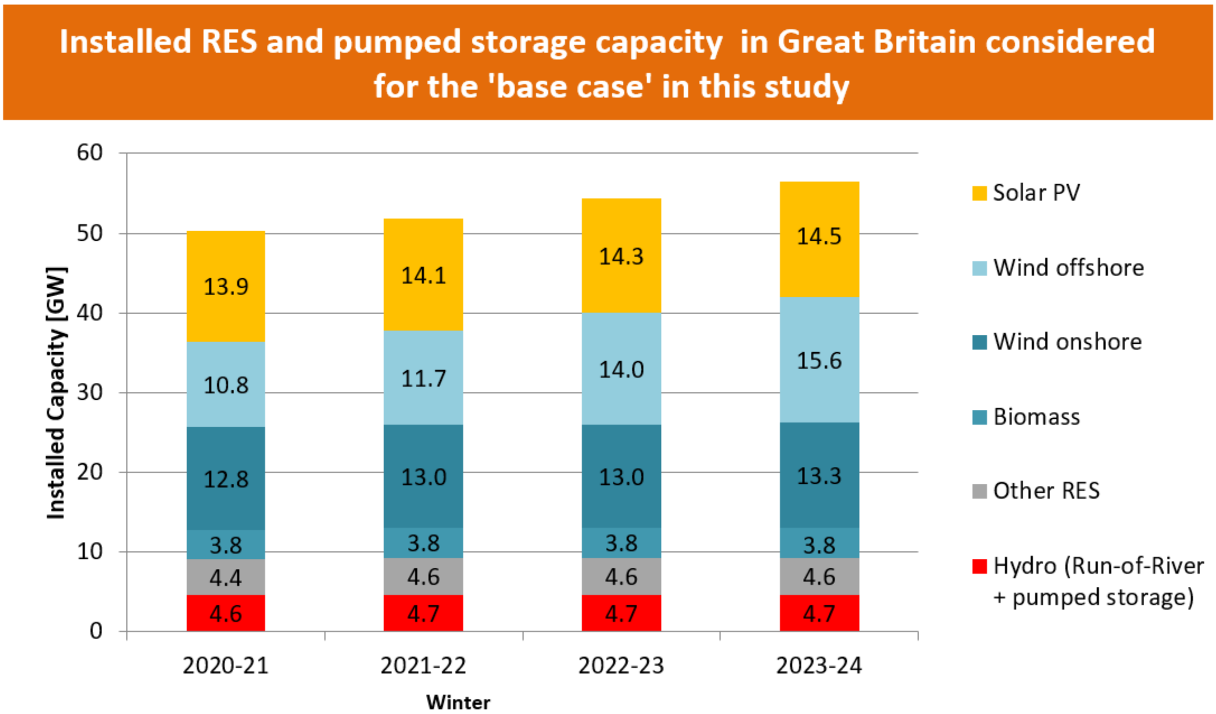


Figure 4.13

4.5.2 Electricity demand in Great Britain

For all winters, around 1.1 GW of demand-side response is assumed for Great Britain, in line with what National Grid communicated to ENTSO-E in the context of the MAF 2020.

4.5.3 Security of supply in Great Britain

Since winter 2017-18, Great-Britain's security of supply has been managed through its capacity market (CM). National Grid ESO performs analyses on the capacity that needs to be contracted to enable Great Britain to meet its adequacy criterion, namely an average LOLE of less than or equal to three hours.

4.6 Luxembourg

Modelling the situation in Luxembourg is important for Belgium because part of the country is connected to the Belgian control area (the 'LUb' zone in Figure 4.14). In 2016, the CCGT plant located in Luxembourg but belonging to the Belgian control area was shut down definitively. Since that closure, the LUb zone contains only consumption. The consumption in that zone is therefore counted as part of Belgium's load. The two other electrical zones in Luxembourg are:

- a part connected to France (LUf) that only contains load;
- the remainder of the country, which is connected to Germany. This zone includes all the country's hydroelectric capacity, wind, PV and residual load;

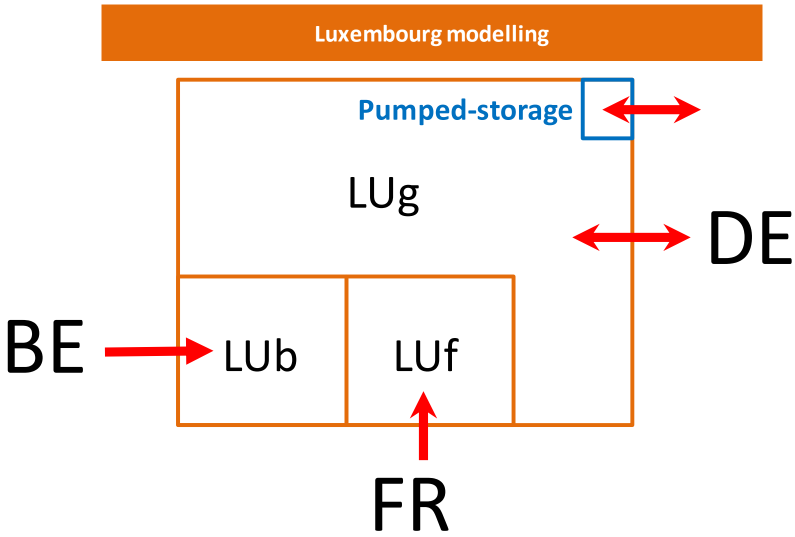


Figure 4.14

4.7 Other countries modelled

This study models 23 countries in all, making assumptions about each of them regarding non-renewable generation facilities, demand and renewables. Most of these assumptions are based on pan-European adequacy studies, such as the mid-term adequacy forecast published this year covering 2025 and 2030 (see section 1.7.3 for more information), ENTSO-E transparency platform [16], ENTSO-E statistics [22], bilateral contacts, PLEF adequacy study and national reports and statistics.

5 Interconnection modelling and assumptions

Belgium is at the heart of the interconnected European grid. It is surrounded by France, the Netherlands, Germany, and Luxembourg, which, depending on the situation of their respective grids and markets, can each import or export large amounts of electricity. Moreover, as of 31 January 2019, the Nemo Link® interconnector enables Belgium to exchange electricity directly with Great Britain. Furthermore, the ALEGrO interconnector has been commissioned in Q4 2020. As Belgium is structurally dependent on imports to ensure its adequacy, correct modelling of these interconnections is crucial.

Exchange capabilities between countries are modelled in this analysis in the same way as foreseen on the day-ahead market:

- Commercial exchanges **inside the CORE** region are taken into account using the **flow-based** methodology as foreseen for operational use in the future day-ahead market coupling (see Figure 5.1). How this works in reality as well as how it has been adapted in the model is described in section 5.1.
- Exchanges between **other countries and the CORE zone** are modelled with **fixed exchange capacities** (also called NTC – Net Transfer Capacities). See section 5.2 for more information.

Figure 5.1

5.1 Flow-based in the CORE zone

5.1.1 Why is the flow-based methodology applied for this study?

Belgium's central location in Europe means that the country's import and export capabilities are heavily defined by the flow-based methodology used at regional level for the day-ahead markets. Its net position is therefore linked to the net position of the other countries in the CORE zone and to the flow-based domain defining the possibilities for exchanges of energy between those countries. It is therefore critical to replicate market operations as closely as possible in order to quantify the country's loss of load expectation. The flow-based method makes it possible to properly take into account interactions between market outcomes and the transmission grid. For instance, at times when both France and Belgium are facing a structural shortage, there may be a significant decrease in Belgium's achievable imports. Using the flow-based method in this assessment makes it possible to calculate the likelihood and impact of reduced imports on adequacy as a result of market conditions in neighbouring countries. Figure 5.2 shows the flows between four fictitious zones when 100 MW is exchanged from zone A to zone D. The resulting flows follow the path of least impedance. This will result in flows between zones not participating in this energy exchange (zones B and C for example). This example illustrates the basic principle behind and reason for introducing a flow-based approach into the market coupling.

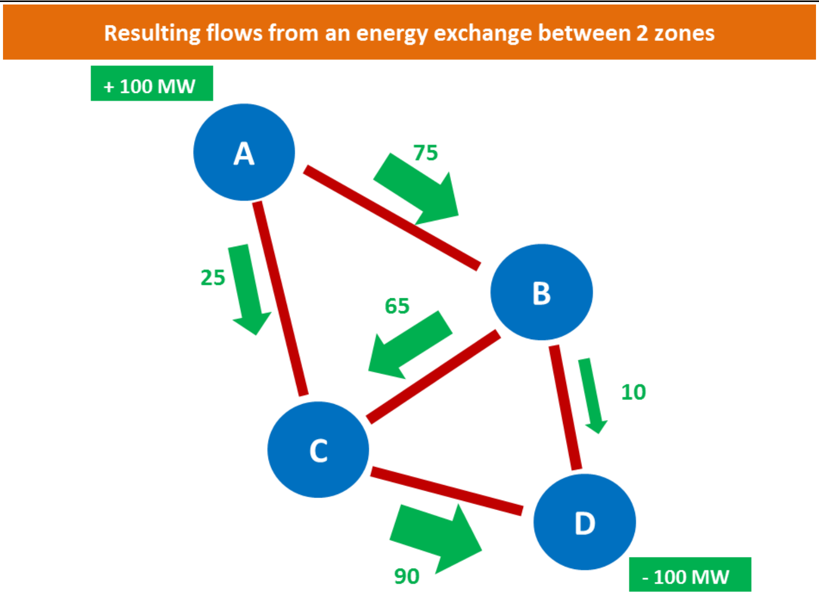


Figure 5.2

The flow-based capacity calculation is a complex process involving many parameters. Multiple approaches are possible when building market models where market exchanges adhere to the rules depicted in a flow-based coupled market. For short term forecasts and analyses, a framework relying on the flow-based domains conceived in the SPAIC process was developed [46]. However, this framework relies heavily on historical data, and becomes more complex and less accurate when multiple parameters and inputs are expected to change between the historical data and the targeted time horizon. Elia has therefore developed a flow-based framework which does not rely on historical domains, but instead aims to mimic the operational flow-based capacity calculation workflow, for which the required inputs are forecasted for the targeted time horizon. One of the key advantages of using such a method is that it enables modelling of the impact of minRAM evolutions on the domains.

5.1.2 How does the flow-based method in the day-ahead market work operationally?

An informative explanation (in French) of flow-based market coupling is available. It is based on a film produced by the French energy regulator (CRE) [36].
More information about the flow-based rules and methodologies is available from the JAO resource center [39] and EPEX Spot Belgium [40].

The flow-based method implemented in day-ahead market coupling uses Power Transfer Distribution Factors (PTDFs) that make it possible to model real flows through the physical network lines as a result of commercial exchanges between countries after market coupling.
For each hour of the year, the impact of energy exchanges on each Critical Network Element (also called critical 'branch') taking into account the N-1 criterion is calculated (see box on the N-1 criterion). The combination of Critical Network Elements and Contingencies (CNECs) forms the basis of the flow-based calculation.
A reliability margin on each CNEC is considered and, where appropriate, 'remedial actions' are also taken into account. These actions can be taken preventively, or after an outage has occurred, to partly relieve the loading of the concerned

critical network element. Those actions make possible to maximise exchanges thanks to changes in the topology of the grid or the use of phase shifting transformers.

This procedure finally leads to constraints which form a domain of safe possible energy exchanges between the CORE countries (this is called the flow-based domain).

Different assumptions are made for the calculation of this domain, such as the expected renewable production, consumption, energy exchanges outside the CORE area, location of generation, outage of units and lines, etc.

For every hour there might be a different flow-based domain because:

- the topology of the grid can change;
- outages or maintenance of grid elements can be present;

The operational calculation of the flow-based domain for a given day is started two days before real-time operation and is used to define the limits of energy exchange between countries for the day-ahead market.

The N-1 security criterion for the grid

Interconnection capacity takes into account the margins that transmission system operators (TSOs) must maintain in order to follow the European rules ensuring the security of supply. A line or grid element can be lost at any time. The remaining lines must be able to cope change in electricity flow due to any such outage. In technical terms, this is called the N-1 rule: for a given number N of lines that are transmitting a given amount of energy, there cannot be an overloaded line in case of the outage of one of the lines. The flow-based domain is calculated taking into account N-1 cases.

Note however, that European rules stipulate that this criterion must be fulfilled at each moment, including in the event of maintenance or repair works. In such cases, it is possible that interconnection capacity available for exchanges will have to be reduced. Wherever possible, maintenance and repair works are avoided during the most critical periods, e.g. around the peak consumption times of the year, but cannot be ruled out, especially after winter weather conditions.

5.1.3 Evolution of flow-based modelisation

5.1.3.1 Evolution of the short-term flow-based methodology

Elia is a pioneer in the flow-based approach for adequacy studies, and has developed a methodology to model exchanges between countries in the capacity calculation region that replicates the day-ahead operation. Whereas in the first flow-based assessment of winter 2016-17 only one domain was used to represent the entire winter, Elia has since improved its modelling by:

- adding more domains;
- relating the domains to the climatic variables in a systematic way;
- incorporating minRAM evolutions;
- correcting historical domains for historical grid outages;
- correcting historical domains for future grid upgrades;
- integrating the breakup of the DE-AT bidding zone on 1 October 2018;
- recalculating the domains to include the planned HTLS upgrade of the 380-kV Belgian backbone;
- modelling the ALEGrO interconnector, which provides additional freedom for the flow-based domain;
- introducing the flow-based framework (no reliance on historical domains);
- extending the flow-based perimeter to CORE.

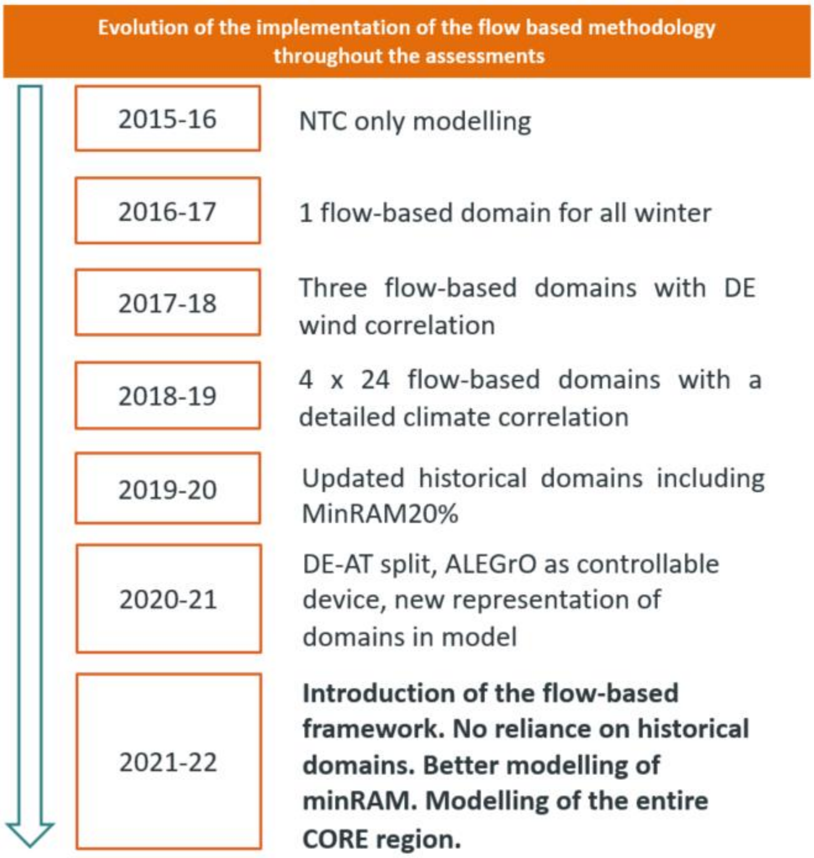


Figure 5.3

The use of the flow-based framework also has the advantage that it can cope with the evolution of the minRAM based on the action plans and derogations submitted by TSOs. These trajectories are intermediate steps towards the set target of 70% minRAM by 2025 (see Table 1).

Country	2020	2021	2022	2023	Justification
Netherlands	28.0	37.0	45.0	53.0	Action plan for most constraining XB CNEC
Belgium*	70.0	70.0	70.0	70.0	*with application of derogation
Germany	21.3	31.0	40.8	50.5	Action plan
France	70.0	70.0	70.0	70.0	
Slovenia	70.0	70.0	70.0	70.0	
Hungary	70.0	70.0	70.0	70.0	
Croatia	70.0	70.0	70.0	70.0	
Romania	70.0	70.0	70.0	70.0	
Czechia	70.0	70.0	70.0	70.0	
Austria	70.0	70.0	70.0	70.0	
Slovakia	70.0	70.0	70.0	70.0	
Poland	70.0	70.0	70.0	70.0	

Table 1: minRAM trajectories within CORE

5.1.4 Flow-based adaptation in the simulations

The bidding zones act as 'copper plates' [20] from a market perspective. Within a bidding zone the market price is the same for all market participants. A smaller resolution is then required in order to simulate the internal flows and consequently assess the loop flows. A finer grid resolution is provided by 'small zones', which also serve as copper plates. Therefore, an initial simulation involving these small zones is required in order to take account of the loop flows caused by internal exchanges (between small zones). Finally, due to the extra complexity arising from the large number of constraints induced by the modelling of flow-based in the adequacy study, the complexity of the problem must be reduced to a level that is solvable in due time by today's computers. This whole process will be detailed further in the sections below.

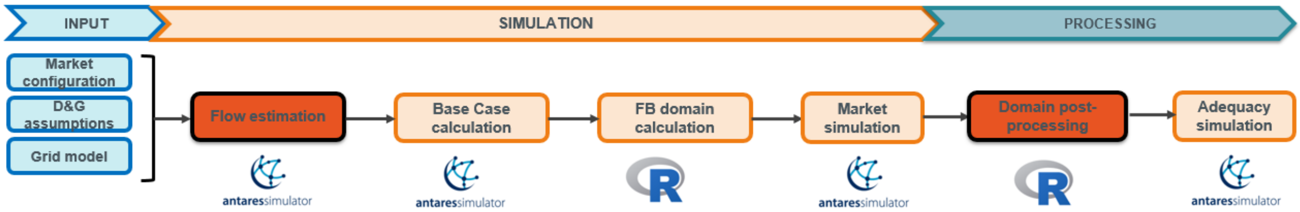


Figure 5.4

5.1.4.1 Calculation of PTDFs

The first step in the flow-based framework is the definition of a set of PTDFs. To obtain these, a European grid model is built, which is for this study based on the TYNDP 2020 reference grid, to which grid modifications for Belgium are applied at the 2021 target horizon. This grid model is then used to calculate the PTDFs. A PTDF matrix consists of lines/rows representing the different CNEC's that are taken into account, and columns representing the variables in the flow-based domain. Each CNEC refers to the combination of a Critical Network Element and a Contingency. The variables can represent the net positions of the market nodes under consideration, the HVDC flows, PST positions, etc; depending on the degrees of freedom of the market coupling algorithm. Aside from a PTDF matrix, the flow-based framework also requires the capacity of each Critical Network Element. These capacities correspond to the steady-state seasonal ratings of the network elements.

5.1.4.2 Flow-based perimeter

The perimeter describes the zone in which flow-based market coupling is in effect. In 2015, the first European flow-based market coupling was established in the CWE region (BE+DE/LU/AT+FR+NL). In 2018, the Germany-Luxembourg-Austria bidding zone split into separate Germany-Luxembourg and Austria bidding zones. This means that today, in 2020, the perimeter includes five bidding zones: BE, DE/LU, FR, NL and AT. A project to launch flow-based capacity calculation for the CORE region (Figure 5.1) has been launched. The go-live date of a CORE-wide flow-based market coupling (FBMC) is expected to be in mid-2021. Therefore, CORE will be taken as the perimeter for this year's strategic reserve volume assessment. This means that instead of the six dimensions of CWE, the domains take into account the 13 dimensions of CORE (including ALEGrO): FR, BE, DE, NL, AT, CZ, PL, SI, RO, HR, SK, HU and ALEGrO.

This is a major evolution with regard to the methodology used in the 10-year adequacy and flexibility study 2020-30 [44]. Including additional zones significantly increases the complexity of the domain and therefore also the calculation requirements.

[20] The 'copper plate assumption' entails unlimited transmission capacities within the zone

5.1.4.3 Calculating the initial loading of each CNEC

For this study, in line with current market operations, CORE is modelled as a flow-based region. The variables are the net positions of the countries involved in CORE (FR, BE, DE (and LU), NL, AT, CZ, PL, SI, RO, HR, SK, HU) , with the addition of ALEGrO as an extra dimension. Flows outside CORE are subject to NTC constraints, and the interaction between the flow-based region and flows over external borders to countries beyond CORE are modelled using standard hybrid coupling. ALEGrO is viewed as one of the dimensions of flow-based, introducing a 13th variable into the PTDF matrix. This flow estimation procedure mimics the capacity allocation and congestion management (CACM) capacity calculation (CC) process and allows for a good estimation of the pre-loading on CNECs. Once fully set up, the flow-based framework performs an initial simulation to determine the initial loading of each CNEC. In this simulation, around 1/2 of the PST tap ranges in Belgium and about 1/3 for other countries can be used to optimize initial flows in order to maximize the welfare of the system. The flows from this simulation determine the 'Reference Flows'. These flows are then scaled back to zero-balance flows per Bidding Zone through the use of Generation Shift Keys (GSKs).

5.1.4.4 Calculating the FB capacity domain

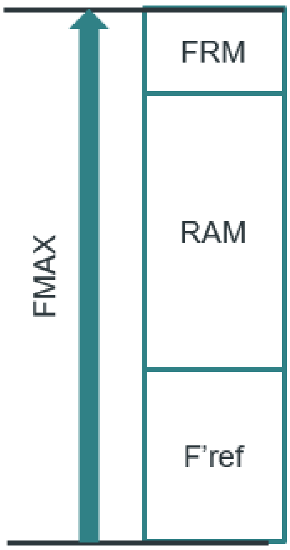


Figure 5.5

European legislation requires a minimum capacity of each critical network element (margin) to be made available to the market (minRAM). For this reason, every time a CNEC’s margin after preloading is less than the required minimum margin given to the market, the minimum margin is guaranteed. This second step will mimic the CACM Capacity Allocation and will permit to isolate the loop flows. Again these flows are scaled back to zero-balance flows per Bidding Zone through the use of generation shift keys (GSKs). These estimates are then used to delimit the flow-based domain (F'ref=Internal flows + Transit flow outside CORE + Loop Flows).

5.1.5 Domain post processing

The objective of the post-processing is to reduce the complexity of the problem so that it becomes solvable within a reasonable time. Indeed simulations with 8,760 hourly domains of 13 dimensions combined with a certain amount of Monte Carlo years would not be feasible within the time frame of the study. Each flow-based domain is a 13-dimensional shape, with one dimension for each of the 13 variables (which can be reduced to 12 using the zero sum constraint). To reduce the complexity of the problem, the 8,760 hourly domains are clustered into 10 sets of representative domains. For each of the 10 sets the centroid is then used for the other hours in the same set. To cluster domains into groups of similar domains, we need a metric that can be used to assess the similarity of domains. To do this, the domains will first have to be enumerated as vertices. For the full-dimensional polytopes this process is very time consuming and not solvable in the time frame set aside for the strategic reserve. Therefore, the number of dimensions of the domains will be reduced to the six dimensions deemed most relevant to Belgian security of supply (CWE + ALEGrO) before enumeration. Through 'smart slicing', the six-dimensional polytope describing the feasible net positions of the six most relevant dimensions is obtained. The positions of the other dimensions are defined by a market simulation that sets the net positions of these country for each hour.

5.1.5.1 Clustering of domains

The clustering of the 8,760 domains is based on their geometrical shape. For this it is important to define a good similarity metric between domains. Next, the number of clusters to retain must be defined. A pre-cluster data split will be applied (seasonal split, weekends vs weekdays) to assess potential representative trends. The groups retained are as follows: one each for the winter and summer seasons, one domain for the weekend and two domains for off-peak hours and two domains for peak hours, resulting in a total of 10 domains (see Figure 5.6). These groups are defined to be representative of the various possible typical positions and to ensure that the problems are solvable within reasonable time. The clustering is performed by means of a k-medoid algorithm. Here the medoids are elements which are part of the initial domains, and therefore have physical meaning. As the strategic reserve study is focused on winter, the focus will be on the five winter domains.

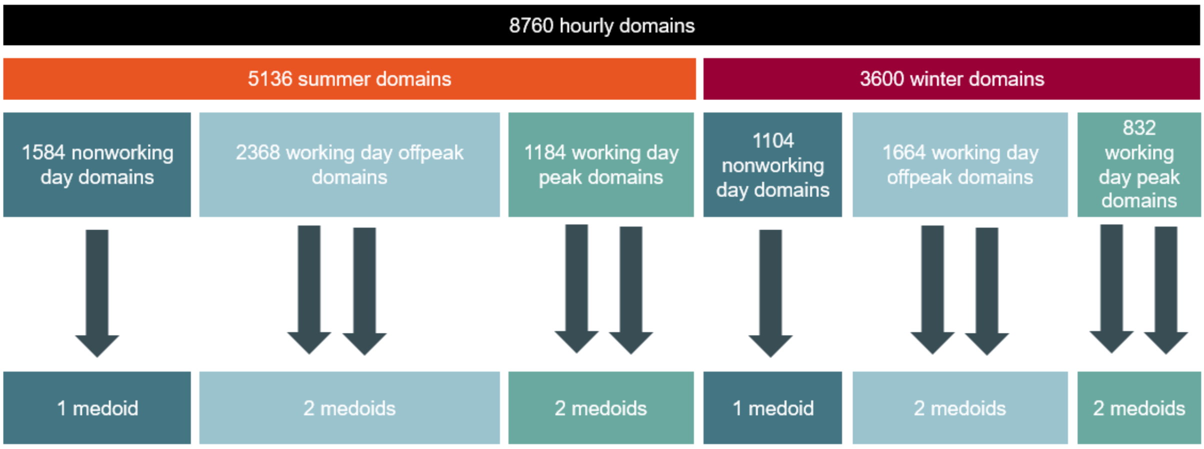


Figure 5.6

The domains are subsequently scaled back to their full dimensions prior to plugging them back into the ANTARES model. By way of reminder, this dimensional reduction was performed in order to be able to compare domains between each other.

5.1.6 Approximating the domains for computational efficiency

In general, the number of CNECs in the framework's domains is too large to be of practical use in market simulations. A flow-based domain is defined by a certain number of inequality constraints depicting the critical branches occurring at a given time. Keeping the complexity at an acceptable level is key to managing to perform the simulation. To do this, only the smallest set of CNECs that can be used to describe the entire domain are kept for plugging into the model.

5.1.6.1 Incorporating multiple flow-based domains into the adequacy assessment

The 'Monte Carlo' approach used in this strategic reserve volume assessment generates possible future scenarios, called 'Monte Carlo' years or 'Monte Carlo' scenarios. The method used for relating typical days to the climatic conditions as they occur in the Monte Carlo scenarios was developed by the French TSO RTE (see reference documents [42] and [25]), and is also implemented in RTE's adequacy study (*Bilan Prévisionnel* since 2017 [32]) as well as in the *Pentalateral Energy Forum - GAA 2018 Report* (PLEF 2017) published in January 2018 and the latest MAF 2019 report[13].

This method can be understood as follows. The k-medoid algorithm, not only selects the representative domains for each of the clusters, but also identifies for each day the cluster to which it belongs. Additionally for each historical day, climatic data is available. Thus, for the climatic variables in scope, thresholds can be defined (typically at the 33rd percentile and 66th percentile) which lead to the creation of climatic groups. As such, it is possible to identify, for every historical day, the climatic group to which it belongs. The population of these climatic groups directly leads to a probability distribution per representative domain. Alternatively, one can identify the probability of finding either one of the representative domains given a set of climatic conditions. It is this interpretation that is used when mapping the typical days onto the 'Monte Carlo' years.

This kind of systematic approach makes it possible to link specific combinations of climatic conditions expected next winter, e.g. high/low wind infeed in Germany, high/low temperature and demand in France and Belgium, with representative domains for these conditions.

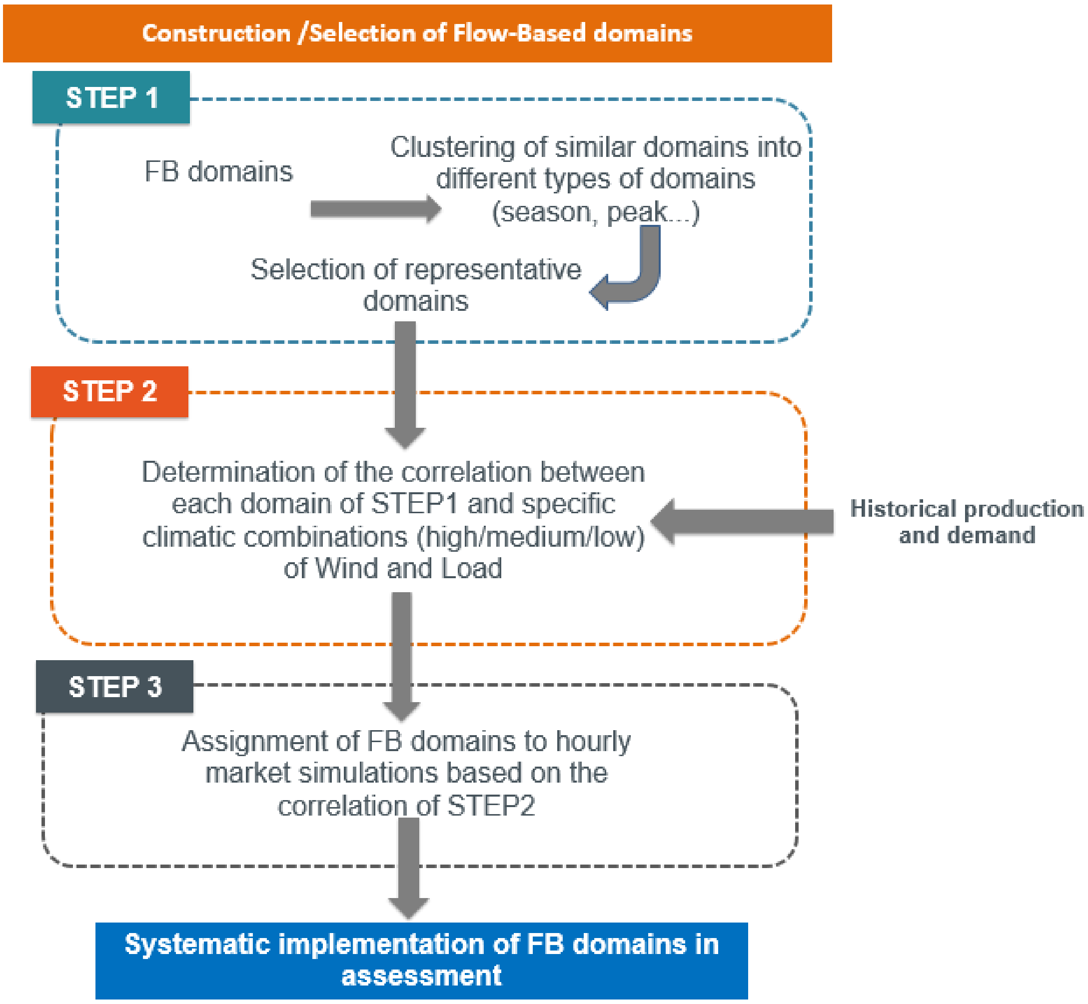


Figure 5.7

5.1.7 Illustration of the domains used for this study on the BE-FR CWE net positions

As described in section 5.1.6.1, the probability of finding a domain given a certain set of climatic conditions can be derived from the cluster process' results. The probability matrices for each of the four winter workday domains is given in Figure 5.8.

Winter working day offpeak hour 1		DE wind Low	DE wind Medium	DE wind High
FR load	Low	79%	87%	82%
FR load	Medium	40%	41%	34%
FR load	High	56%	35%	50%

Winter working day offpeak 2		DE wind Low	DE wind Medium	DE wind High
FR load	Low	21%	13%	18%
FR load	Medium	60%	59%	66%
FR load	High	44%	65%	50%

Winter working day peak hour 1		DE wind Low	DE wind Medium	DE wind High
FR load	Low	13%	13%	13%
FR load	Medium	9%	11%	13%
FR load	High	9%	12%	18%

Winter working day peak hour 2		DE wind Low	DE wind Medium	DE wind High
FR load	Low	87%	87%	87%
FR load	Medium	91%	89%	87%
FR load	High	91%	88%	82%

Figure 5.8

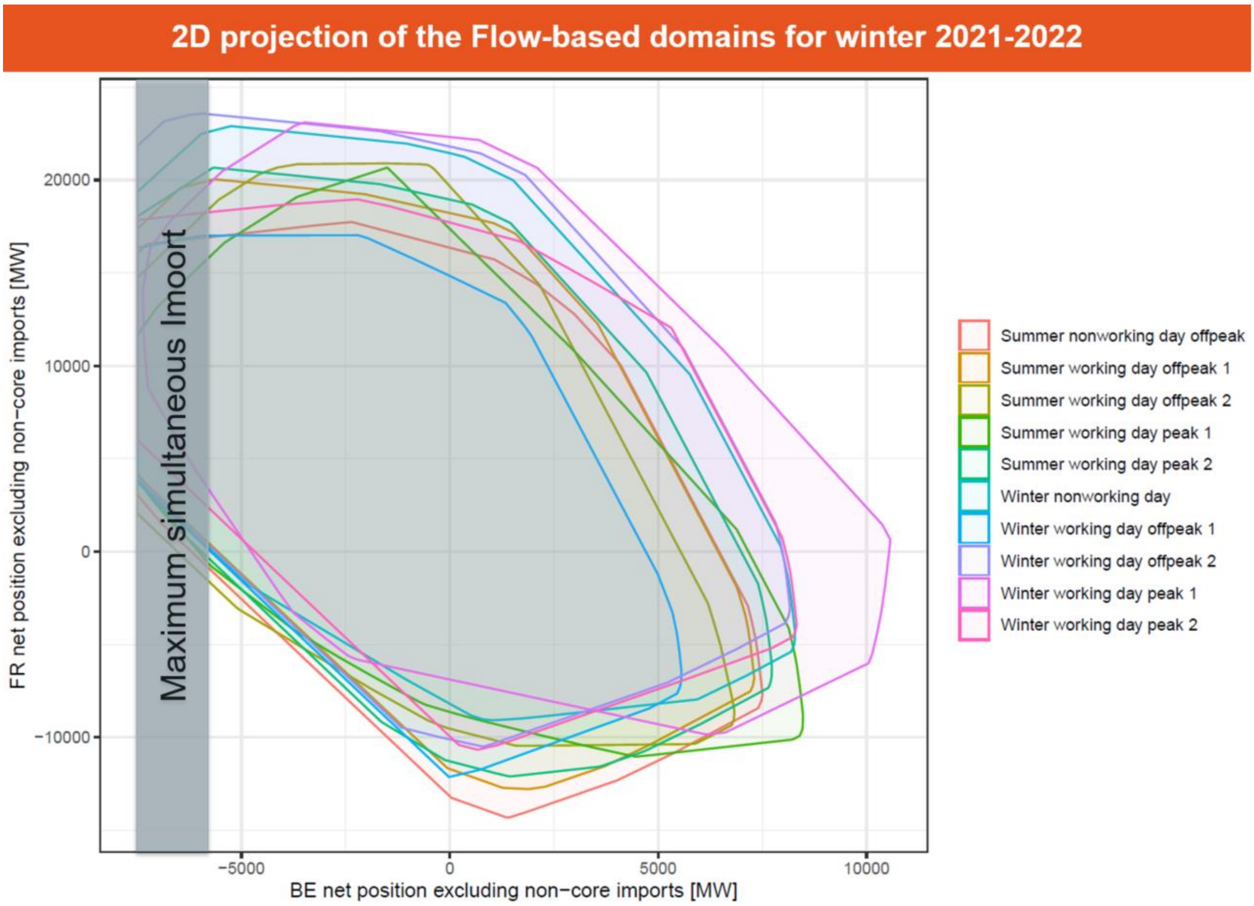


Figure 5.9

5.1.8 Maximum simultaneous import capacity for Belgium

Belgium's maximum simultaneous import capacity is the maximum power that the country can import under normal grid operation conditions, meaning without either planned or forced outages of the grid infrastructure, (in Belgium and in the neighbouring countries) that results from the need of ensuring sufficient available resources for voltage regulation, short-circuit power and inertia that are normally offered by the countries' internal production. In the event of considerable imports, steps must be taken to ensure that such production is still sufficiently present.

The Nemo Link® HVDC interconnection with Great Britain, commissioned in early 2019, was taken into account in all simulations. The link is modelled as an NTC link, and the connection has an exchange capability of 1000 MW between Belgium and Great Britain. The maximum simultaneous import capacity for Belgium thus accounts for:

1. imports into Belgium from CWE including the effect of the ALEGrO interconnector [34];
2. imports or exports over the Nemo Link® interconnector [35]

The additional voltage regulation possible thanks to the ALEGrO project will enable Belgium to increase its maximum simultaneous import capacity to **6500 MW** in the assessment for winter 2021-22. The maximum import constraint can be represented on a 2D projection of the flow-based domains as shown in Figure 5.10, where an illustration of the domains when there are no non-CORE exchanges with Belgium.

In its Federal Development Plan [38] Elia envisages a further increase in the maximum simultaneous import capacity to **7500 MW**, thanks to addtionnal investments in additional voltage control elements. Accordingly, Elia uses 7500 MW as the maximum simultaneous import capacity figure for the both winters 2022-23 and 2023-24.

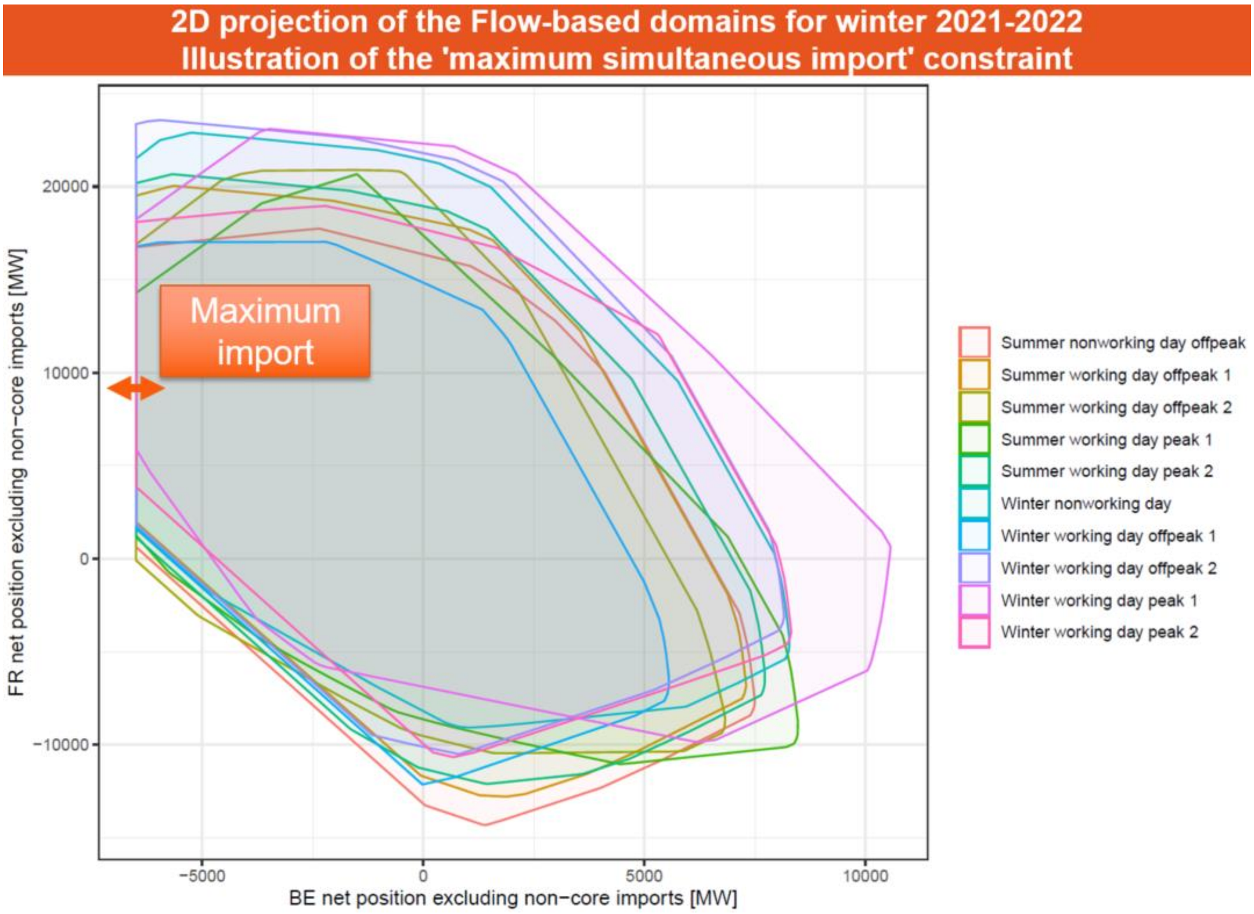


Figure 5.10

The adequacy patch

If several countries rely on import to ensure its adequacy, *ie.* have a structural shortage (day-ahead price reaches price cap in those countries), the market might not necessarily dispatch all available energy to those markets in the most fair way. Instead, the market tries to optimise the global welfare, hence tries to minimize the global energy non-served (ENS).

Due to flow factor competition, it might be more beneficial to dispatch energy towards countries which affect *less* the available transmission capacity, *ie.* countries which cause less congestions in the grid for the same level of commercial exchanges, thereby freeing up transmission capacity on another borders, and hence leading to additional exchanges and to additional welfare and/or additional reduction of ENS.

Still the EU-wide algorithm methodology includes principles regarding rules for curtailment minimization and sharing and hence on how energy exchanges are allocated in scarcity situations. These curtailment minimization and sharing rules in the EUPHEMIA algorithm are referred here as the 'adequacy patch'. These rules are aimed to correct the above mentioned effect of flow factor competition in scarcity situations.

If one country presents a structural shortage, the adequacy patch ensures that the maximal feasible import capacity will be allocated to the country in need, regardless of the global welfare. Also the adequacy patch will ensure that net exporters will not be charged with ENS. These points are related to the so-called 'local matching' constraint.

When two or more countries simultaneously have a structural shortage, imports will be allocated to those countries in proportion to their respective needs, on the basis of the curtailment minimization and curtailment sharing function as defined in the EUPHEMIA market coupling algorithm public description algorithm.

For the purposes of the adequacy study, a modelisation of the adequacy patch is taken into account in the results from ANTARES in post-processing.

5.1.9 Establishing the flow-based domains in the model

The following subsections aim to expand on the methodology to establish flow-based domains in the Antares model.

Understanding 2-dimensional flow-based domain representations

The flow-based domains used in this year's volume assessment are 13-dimensional polytopes. For a better understanding of the domains, a two-dimensional representation is used. This representation is to be seen as a projection of the higher-dimensional domain onto a two-dimensional plane.

To obtain this, first the domain polytope which is described by its planes is enumerated to obtain its vertices. Then these vertices are projected onto the desired plane. A convex hull of these points, which can be seen as the smallest convex polytope which contains all points (or more graphically: the polygon you get when you wrap shrink wrap around all points) is then calculated. All points which are not on the convex hull are omitted. Figure 5.11 shows a theoretical example of such a projection[21]. Note that not all vertices are part of the convex hull.

The resulting 2-dimensional representation of the flow-based domain should be interpreted as follows: "for any point within the 2-dimensional domain, for which the net positions of 2 countries can be read from the axes, a combination of net positions for the countries that are not depicted exists so that this point can be attained".

[21] Web image - source: https://scaron.info/slides/humanoids-2016/index.html#/22

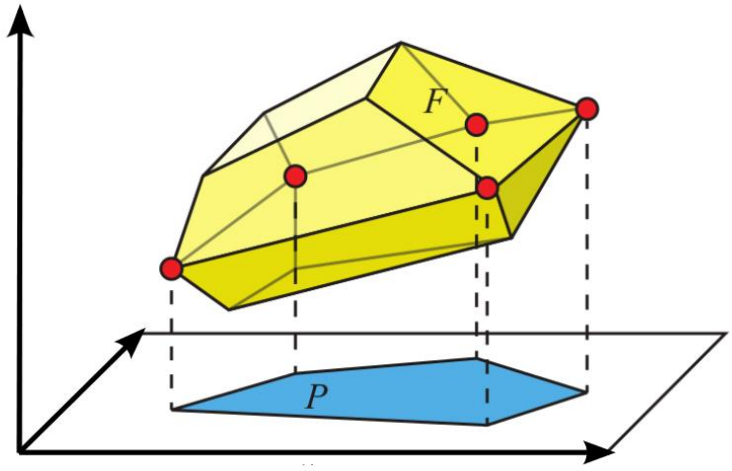


Figure 5.11

As the Belgian adequacy situation is closely related to French security of supply, it is preferable to show a projection of the flow-based domain onto the Belgium-France plane. An overview of the domains is shown in Figure 5.9.

By convention, export is depicted as positive, whereas import is negative. A positive net position thus means a net export position towards CORE.

All flow-based domain representations only depict CORE balances, as opposed to bidding zone balances. Hence, the import possibilities of CORE countries from outside CORE are not shown. In the ANTARES model used for determining the volume of strategic reserves, as well as in the day-ahead market coupling, France can for example import from other countries within the limits of the NTC constraints on the concerned borders.

For Belgium, this distinction is important as the Nemo Link® HVDC interconnector is not part of CORE. Two effects are therefore visible:

- Maximum import cannot be depicted on the two-dimensional domain representation. Depending on the actual net position of Nemo Link®, the Belgian CORE balance can, for the first winter, vary between 5500 MW and 7500 MW corresponding to maximum import and maximum export over NEMO respectively.
- Belgium can in times of scarcity have a positive CORE balance, yet still have a net import position. In these situations, a positive CWE balance is offset by a greater import flow over Nemo Link®.

5.2 Exchange capacities on CORE outer borders

The NTC capacities used in this study are obtained through studies conducted within ENTSO-E and from bilateral and multilateral contacts between Elia and other TSOs. The capacities take into account planned new interconnections for future winters. In reality, NTC's can vary from day to day depending on the conditions of the network and the availability of lines and other network elements. In this study, a single reference value is used for a given interconnection in a certain direction during the entire period simulated. The historical exchange capacities can be found on the websites of the relevant system operators and on ENTSO-E's transparency website [16].

5.2.1 Import capacities of the CORE zone from neighbouring countries

The impact of countries outside the CORE zone on the risk of a structural shortage in Belgium consists of the capacity of these countries to provide energy to the CORE zone in case of a power shortage at CORE level.

The following import capacities (NTC) into the CORE zone are taken into account in this study:

- **Austria**: the total net import capacity for Austria from outside CORE is considered to be **0.2 GW** for winter **2021-22**; this value is the sum of import capacities at the border with Italy;
- **Belgium**: the total net import capacity for Belgium from outside CORE is considered to be **1 GW** for winter **2021-22**, thanks to the HVDC interconnection with Great Britain (Nemo Link®);
- **France**: the total net import capacity for France from outside CORE is considered to be **9.9 GW** for winter **2021-22**; this value is the sum of import capacities at the borders with Spain, Italy, Switzerland and Great Britain;
- **Germany**: the total net import capacity for Germany from outside CORE is considered to be **8.9 GW** for winter **2021-22**; this value is the sum of import capacities at the borders with Switzerland, Sweden, Norway and Denmark;
- **the Netherlands**: the total net import capacity for the Netherlands from outside CORE is considered to be **2.4 GW** for winter **2021-22**; this value is the sum of import capacities at the interconnectors with Norway and Great Britain as well as the 700-MW HVDC cable (COBRA cable [37]) between the Netherlands and Denmark.

The sum of import capacities shown in Figure 5.12 is the maximum possible import capacity at the external CORE borders during winter as assumed in the simulations. The sum of this maximum import capacity (25 GW) may seem high. However, for the whole capacity to be used, the energy must be available in the foreign countries (outside the CORE zone) at times of structural shortage. As the simulation scope includes those countries, the availability of generation is explicitly taken into account.

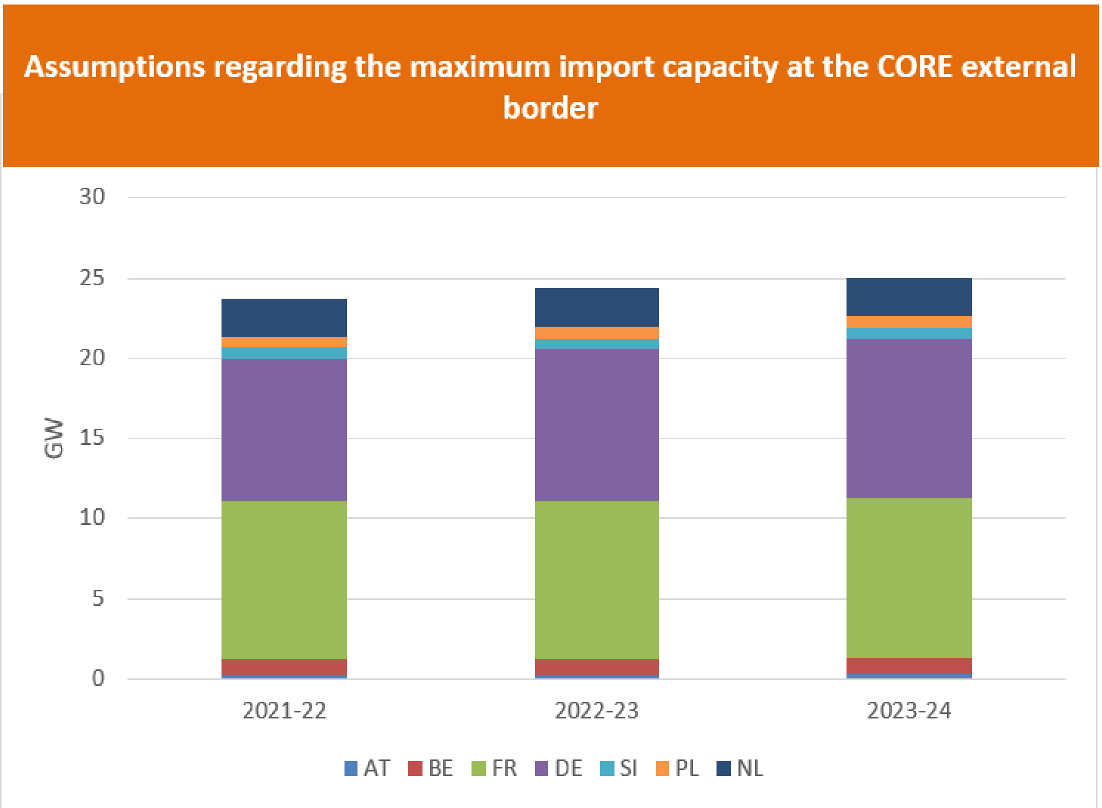
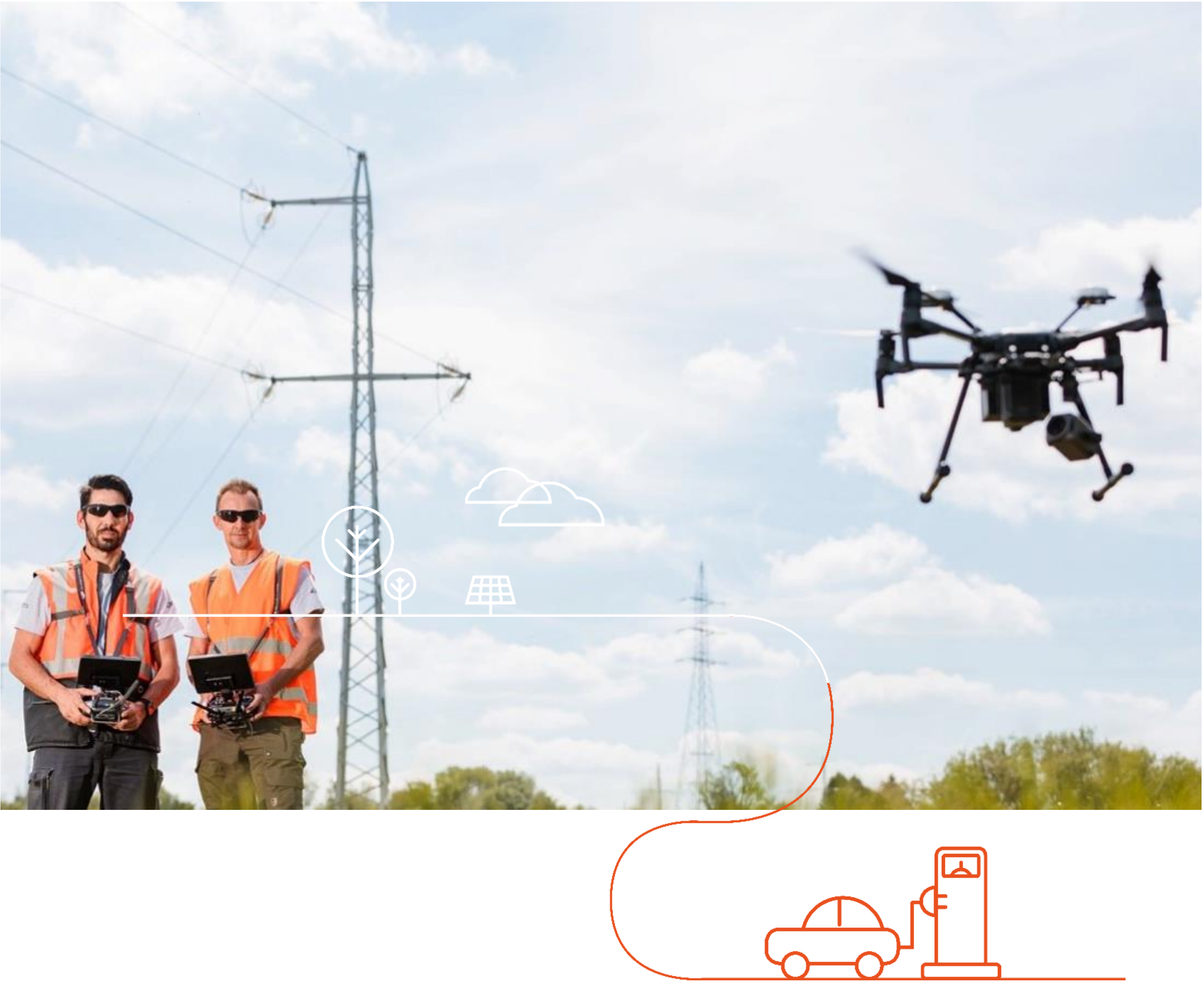


Figure 5.12

Exchanges with non-modelled countries

No exchanges between the countries that are modelled and those that are not modelled are considered. This is a conservative assumption because these exchanges do occur and could contribute to supplying power to the CORE region. Since the geographical perimeter around Belgium is significant, the effect of the above-mentioned assumption has little impact on the adequacy situation in this country.

6 Results



This chapter contains the results for winter 2021-22, with an outlook for winter 2022-23 and winter 2023-24. Section 6.1 provides a detailed analysis of the results for the 'base case' scenario for winter 2021-22. In addition to the 'base case' scenario, a sensitivity regarding nuclear availability in Belgium and France was also analysed for winter 2021-22. This 'High Impact, Low Probability' scenario, together with its results is discussed in section 6.2. Sections 6.3 and 1106.4 present results for winter 2022-23 and Sections 6.5 and 6.6 for winter 2023-24.

The results for winter 2021-22 are presented using the following adequacy indicators:

- The criteria defined by law (**LOLE average and LOLE95**) as discussed in section 1.3, given in hours. The distribution of the LOLE is also presented where the other percentiles can be clearly identified.
- The **Energy Not Served (ENS)**, expressed in GWh. Both the average over all simulated 'Monte Carlo' years is given for the studied winter, as well as the P95;
- The **probability of a structural shortage** for a given winter reflects the chance of having at least one hour of structural shortage;
- The **need for strategic reserve (positive number) or margin (negative number)** in the system in order to reach the adequacy criteria defined by law;
- When a need for a volume of strategic reserve is identified, the **number of activations** and the **length of an activation** of this volume are given with average, P95 and maximum values. When a margin is identified, these numbers are given for a hypothetical volume of strategic reserve.

6.1 Results for winter 2021-22 'base case'

Assumptions

The 'base case' scenario includes the following key assumptions:

- The economic projections of the Federal Planning Bureau from June 2020 [19] were used to derive the total electricity consumption growth in Belgium. Such projections include the expected recovery of the consumption after the drop in 2020 following the Coronavirus disease (COVID-19) pandemic. The scenario results in a drop of -2.5% in electricity consumption for winter 2021-22 when compared to pre-COVID projections;
- In addition, in order to grasp the effect of the expected ‘COVID crisis’ on the electricity consumption in the other modelled countries as well, the same reduction of -2.5% was applied for the winter 2021-22 on pre-COVID projections;
- Installed capacity forecasts for photovoltaic and onshore wind generation are based on the data from the regions, combined with a best estimate made by Elia and FPS Economy about offshore wind generation;
- With the expected go-live of the CORE flow-based market coupling mid-2021, commercial exchanges within the so-called CORE region will be allocated in the Day-ahead market using FB capacity allocation. In a first-of-its-kind improvement in adequacy assessments, Elia explicitly modelled these commercial exchanges using its flow-based methodology. In addition, non-CORE exchanges are also taken into account via their NTC;

— A maximum global simultaneous import capacity of 6500 MW for Belgium for winter 2021-22 is applied. This limit applies to the sum of imports from CORE and the flow on the Nemo Link® interconnector; this limit will increase to 7500 MW for the two subsequent winters thanks to the addition of voltage control elements.
— The latest public information (REMIT) regarding the planned outages of nuclear units (as provided on the transparency websites of the nuclear units' owners dated 15 October 2020) for Belgium and France is used. In addition to any planned outages, the 'base case' scenario takes into stochastically modelled Forced Outage rate. This rate is derived from the Forced Outages as witnessed in the last 10 years. 'Exceptional' outages are not covered by this normal Forced Outage rate, but are treated separately in the 'High Impact, Low Probability' (HiLo) scenario described later;
— It is important to note that the COVID-19 pandemic has significantly impacted the maintenance and refuelling of France's nuclear power plants in 2020: the maintenance had to be rescheduled inducing a higher planned unavailability than historically observed for the upcoming winters.

With respect to Belgian nuclear generation units, it is important to note that, it was assumed based on 15/10/2020 REMIT data that:
— 1 GW is unavailable due to planned maintenance on Doel 3 from 28 Augustus 2021 to 05 October 2021;
— 1 GW is unavailable due to planned maintenance on Doel 4 from 23 October 2021 to 30 November 2021;
— 1 GW is unavailable due to planned maintenance on Tihange 3 from 21 February 2022 to 31 March 2022;
— Additionally, Forced Outages of the remaining nuclear units are statistically simulated at a rate of 3.7%, which is based on historical unplanned unavailability during the last 10 years, excluding long-lasting outages which are covered in the HiLo sensitivies.

6.1.1 Calculation of LOLE, ENS and number of activations

As explained in Chapter 2, a margin or deficit (i.e. a need for strategic reserve volume) is calculated for both legally required criteria (LOLE average and LOLE95). The resulting values are shown in Figure 6.1. The LOLE average for winter 2021-22 is **below 30 minutes** and the percentile 95 is **2 hours**. These results are below the criteria defined by law, and the margin corresponding to the 2021-22 'base case' scenario is **3300 MW**. **There is thus no need for strategic reserves in the 'base case' scenario.**

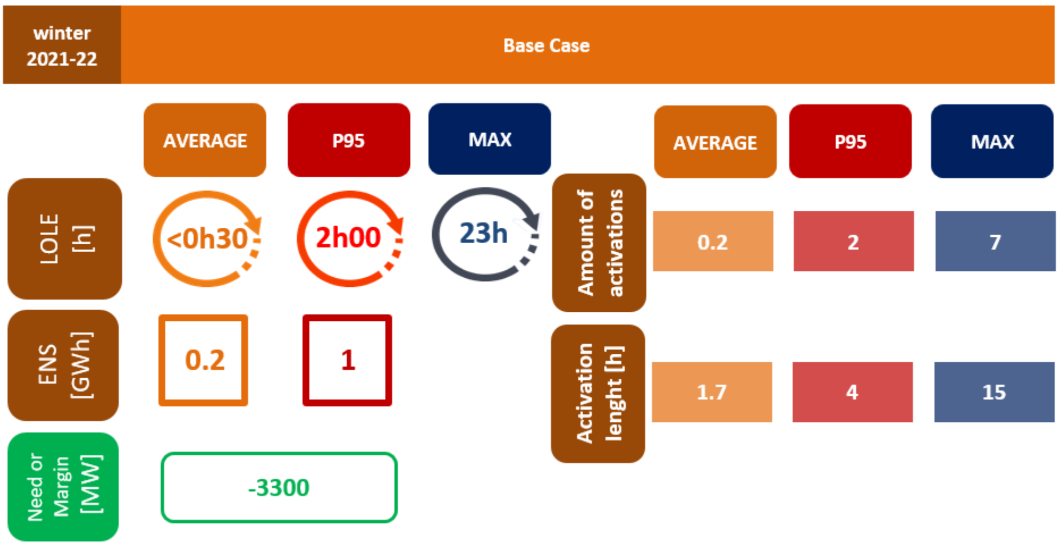


Figure 6.1

As can also be observed in Figure 6.1, the number of activations of a possible volume of strategic reserve would be very low: **0.2 times** per year on average, **2 times** in P95 and up to **7 times** in the most extreme 'Monte Carlo' years simulated. The figure also indicates the maximum duration that a possible volume of strategic reserve would be activated without interruption. For the most extreme simulated event in all the future states, a possible volume would be activated for a maximum duration of **15 hours** without interruption. The average of the activation length is around **1.7 hours**. In the most extreme year simulated, **23 hours** of structural shortage were obtained. However, this is very rare, as shown by the P95 which is limited to **4 hours**. Furthermore, Figure 6.1 shows that the amount of Energy Not Served (ENS) is limited to a value of **0.2 GWh** over the winter on average and to **1 GWh** in P95.

6.1.2 Imports in periods of structural shortage

The hours in which structural shortage is identified for winter 2021-22 in the 'base case' simulation, can be classified on the basis of Belgium's imports during these hours (see Figure 6.2).
In this figure, each point represents one hour in which ENS is identified in Belgium. The graph shows imported energy for Belgium and France within CORE (resulting from flow-based market coupling), and the coloured domains indicate the respective flow-based domain types of each hour relevant for the situations in which ENS was identified. Note that these net positions do not take into account the flows BE-GB and FR-GB as they are not part of the flow-based domain dimension for the considered time horizon.

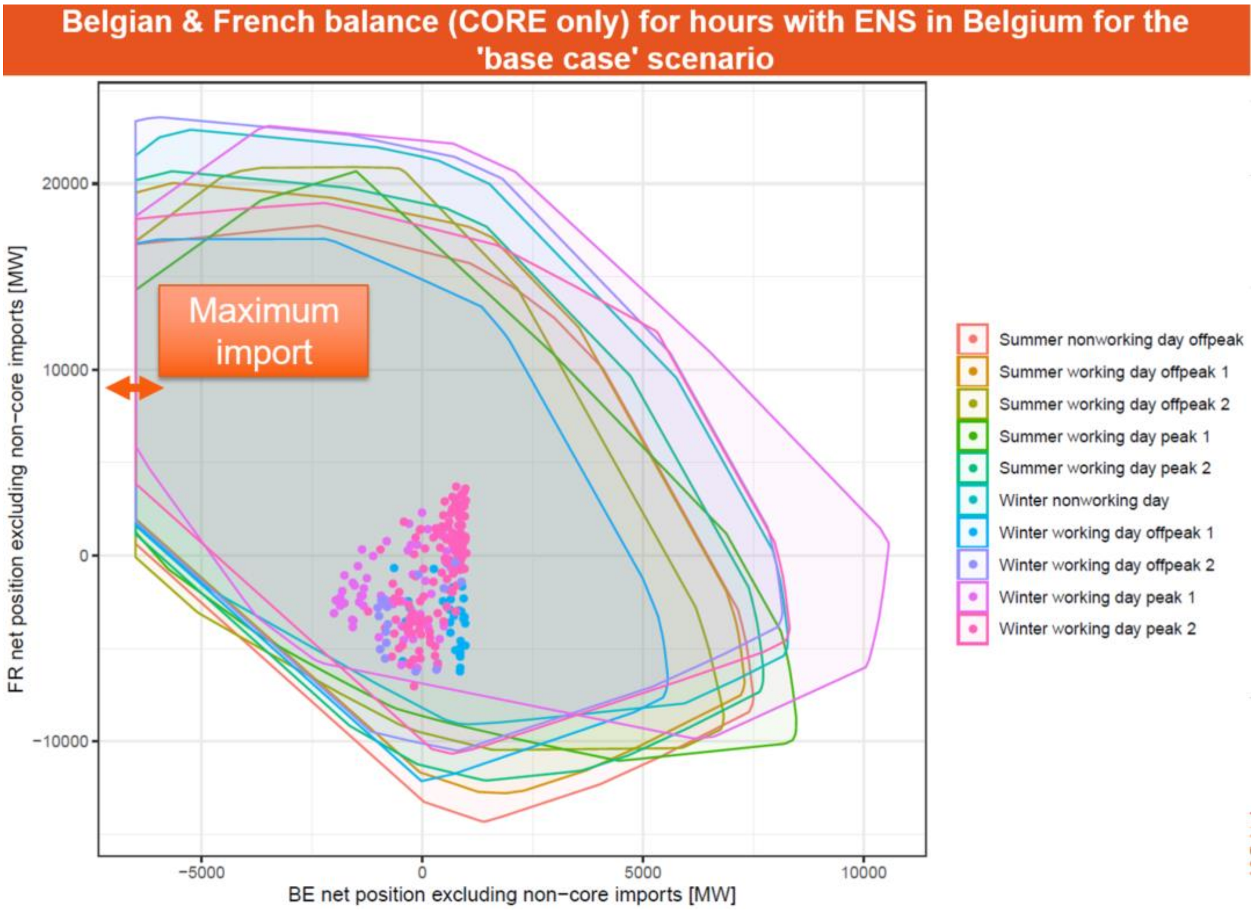


Figure 6.2

The ability to find energy abroad when there is a structural shortage in Belgium is crucial for Belgium's security of supply, due to Belgium's high dependence on imports for its own adequacy. Belgium's ability to obtain sufficient imports in situations of structural shortage will be reduced if its neighbours are also experiencing adequacy problems at the same time. This is graphically represented by Figure 6.2 later on. Furthermore, from the hourly distribution of ENS amongst the Flow-Based domains depicted in Figure 6.3, two main groups can be identified: a morning milder peak between 7 and 9 AM CET and an evening peak concentrating most of the observed ENS between 5 and 8 PM CET.

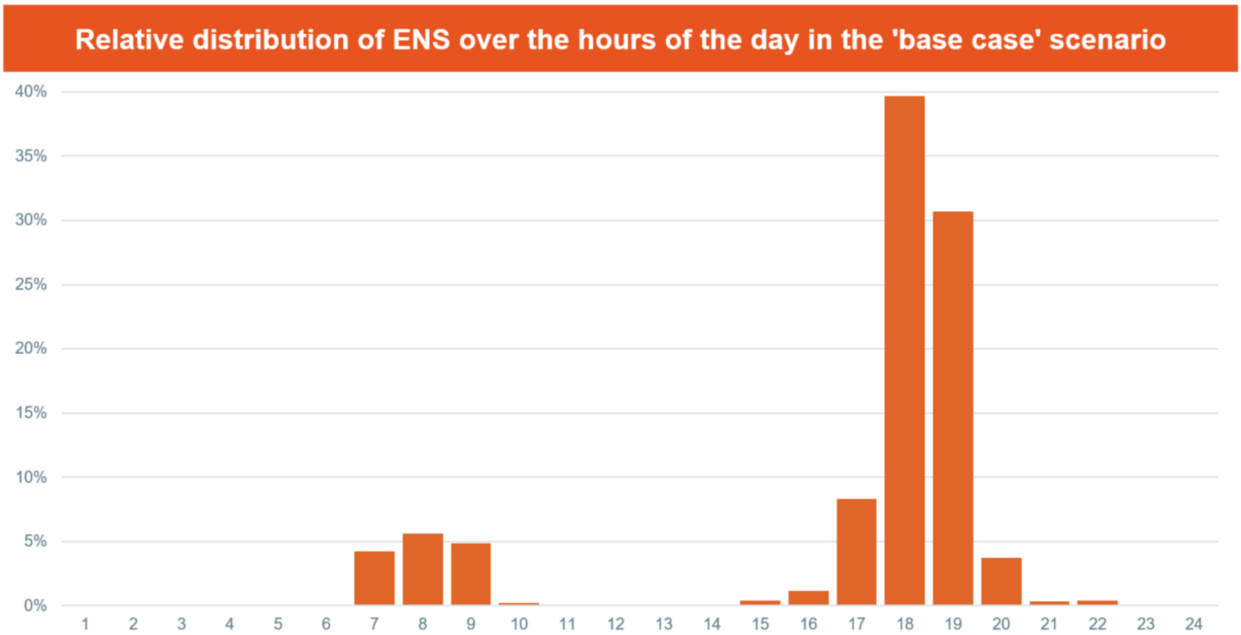


Figure 6.3

6.1.3 Market response impact on adequacy

The market response assumptions used in the 'base case' scenario are explained in section 3.3. This available market response capacity for winter 2021-22, amounting to 1192 MW, is taken into account with constraints on the number of activations and their duration. Figure 6.4 (left) shows two days of the simulation during which a relatively small structural shortage occurs. In such situations, market response helps to cover some of the shortages. It can be seen that market response makes it possible to cover Energy Not Served, resulting in no structural shortage during three situations. This was possible because the number of hours when market response was needed was limited, and the energy that had to be served was below the market response capacity. Figure 6.4 (right) shows a more extreme situation during days of another week where larger volumes of structural shortages occur for several consecutive hours. In such situations, market response is of little help to cover the total Energy Not Served, but will still help to reduce the peaks. Increasing the market response capacity in such cases will also not help, unless the limitations are also reduced.

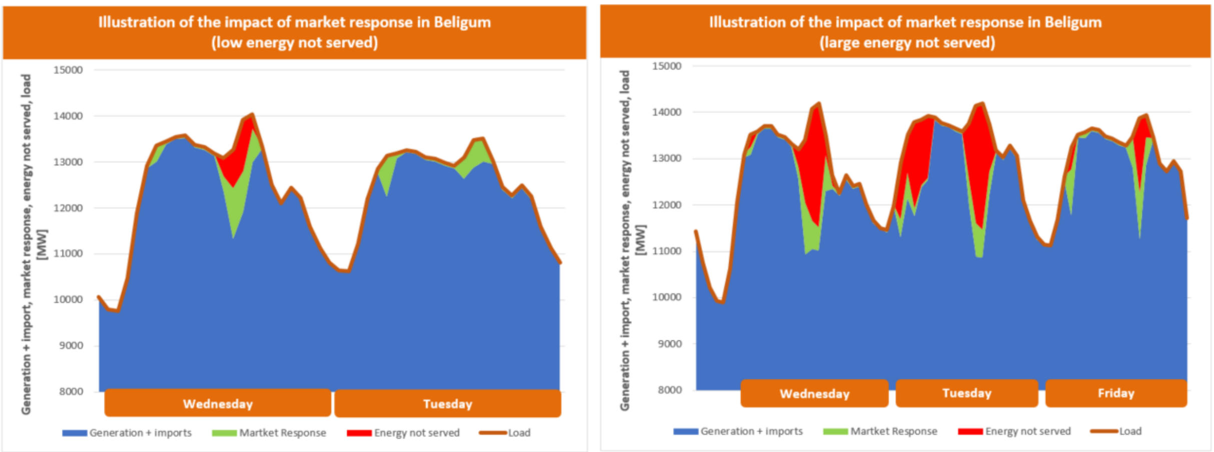
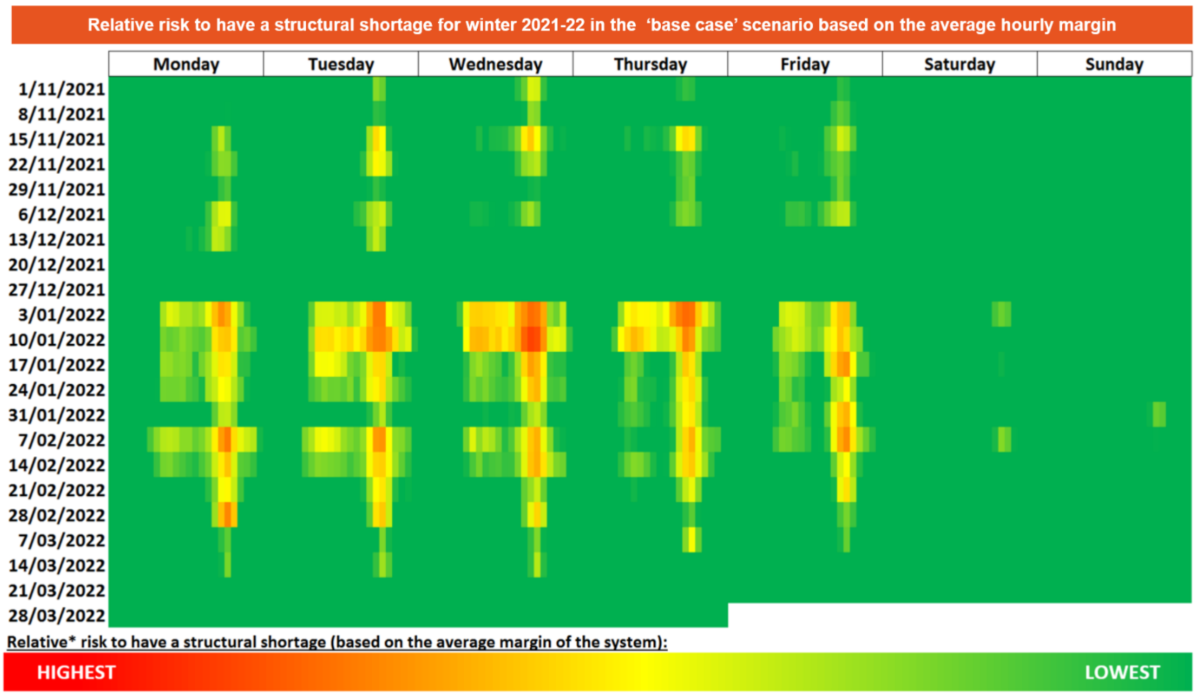


Figure 6.4

6.1.4 When is a structural shortage risk identified in the 'base case' scenario?

The risk of structural shortage in the 'base case' has been calculated from the hourly remaining margin of the system, after taking into account all possible imports within CORE and via Nemo Link® and is shown in Figure 6.5. This 'heat-map' chart is constructed for didactic purposes and makes it possible to clearly identify those times when the risk of structural shortage is the highest. The colour legend shows the relative risks (structural shortages are more likely to happen in hours that are coloured red than hours that are coloured green). In general, the risk follows the country's residual demand (demand minus non-dispatchable generation). Furthermore, effects such as weekday, weekends, peak/off-peak or holidays can be derived from the figure.



Note that the probability to have a structural shortage for the winter 2021-22 based on the base case assumptions is very low and the legal criteria are satisfied without strategic reserve. This figure only shows the relative risk between the hours.

Figure 6.5

6.2 Results for winter 2021-22 'High Impact, Low Probability' scenario

To offer guarantees in terms of the country's security of electricity supply, the 'High Impact, Low Probability' (HiLo) scenario is particularly relevant since it provides protection against events over which the Belgian State has little control or influence. It is this scenario on which previous decisions for the contractualisation of the strategic reserves were based by the public authorities. The use of the "High Impact, Low Probability" scenario for the dimensioning of required strategic reserve has been validated by the European Commission's DG Competition via its decision SA.48648. Section 6.2.1 provides more details about this scenario, together with the elements that justify the analysis of the sensitivity. In section 6.2.2 the results of the sensitivity analysis are given.

6.2.1 Description of the nuclear sensitivity

Due to the large share of nuclear capacity compared to the total installed generation capacity in Belgium, its availability has a significant impact on Belgian adequacy. A series of outages, often simultaneous at multiple nuclear power plants is not unrealistic and have been observed in Belgium since winter 2012-13. Given the unusual nature of those outages, the decision was made not to include them in the forced outage rates of the 'base case' scenario. However, given their significant impact, it is important to analyse a scenario taking such events into account.

In previous adequacy exercises (Strategic Reserve Volume Determination, Adequacy and Flexibility Study for Belgium), the differences in nuclear availability modelled in the 'base case' and the historical Belgian nuclear availability were compared in detail. This comparison was updated with the latest historical data and the result in shown in Figure 6.6. From this figure, we can draw the following two conclusions. Firstly, by analysing the average and P95 of historical nuclear availability it becomes apparent that the 'base case'-modelled nuclear availability is highly optimistic in terms of both indicators. Secondly, due to the fact that simultaneous planned outages of nuclear generation are avoided in both winter periods, the difference between the model's average and P95 availability is similar to last years' analysis. By reducing the available nuclear capacity in the base case scenario by 1.5 GW we are capable of making a good compromise in the model for both indicators (average and P95).

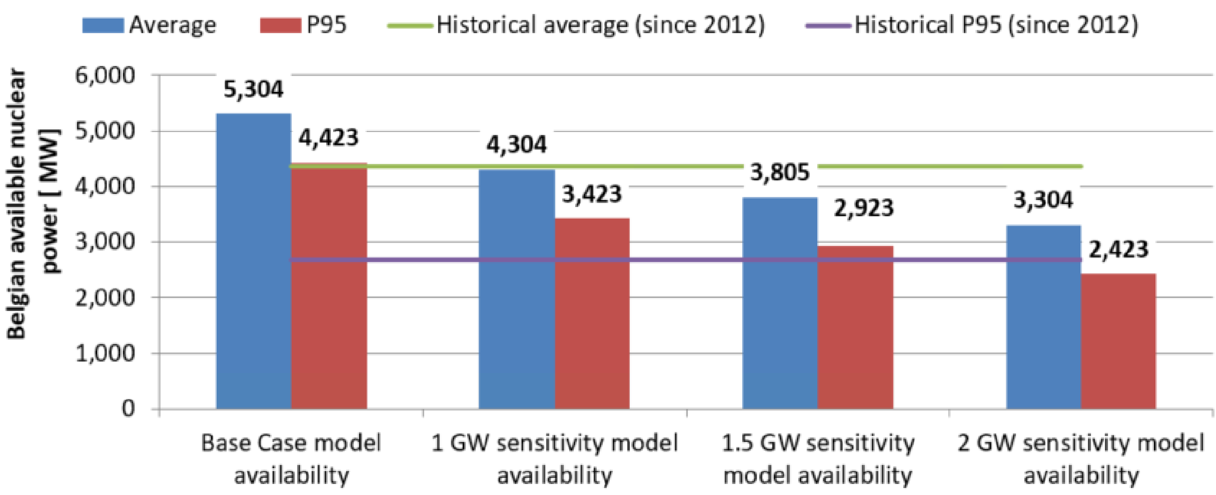


Figure 6.6

It is therefore concluded that 'High Impact, Low Probability' events, as observed during the last 7 winters, could be properly captured by assuming a **sensitivity with an additional 1.5 GW of nuclear production capacity out of service** for the entire winter in Belgium. The sensitivity will be reduced to **1 GW** as of the decommissioning of Tihange 2 in February 2023 when the Belgian nuclear installed capacity will drop to 4 GW. The sensitivity for winter 2023-24 will be **1 GW**.

Likewise, the unavailability of the French nuclear generation fleet has an important impact on the adequacy situation in Belgium, as seen for example in the winter of 2016-17 when multiple nuclear units were temporarily out of service at the request of the French nuclear safety authority. Therefore, in countinuity with last year's approach, in the 'High Impact, Low Probability' scenario, a capacity of 3.6 GW of nuclear generation will be considered out of service in France for the entire winter.

It should be noted that the abovementioned calculated outages for the entire winter, for both France and Belgium, come on top of the planned outages (REMIT) and forced outages already modelled for nuclear as well as the rest of the generation fleet for both countries in the 'base case' simulation.

6.2.2 Calculation of LOLE, ENS and number of activations

As explained in Chapter 2, a margin or deficit (i.e. a need for strategic reserve volume) is calculated to satisfy both legally required criteria (LOLE average and LOLE95). The resulting values are shown in Figure 6.7 for the sensitivity. The LOLE average for winter 2021-22 in this sensitivity is **3 hours** and the percentile 95 LOLE is **18 hours**. These results are within the boundary of the criteria defined by law, and the margin corresponding to the 2021-22 'high-impact low-probability' scenario is **0 MW. There is thus no need for strategic reserves in the 'High Impact, Low Probability'-scenario.**

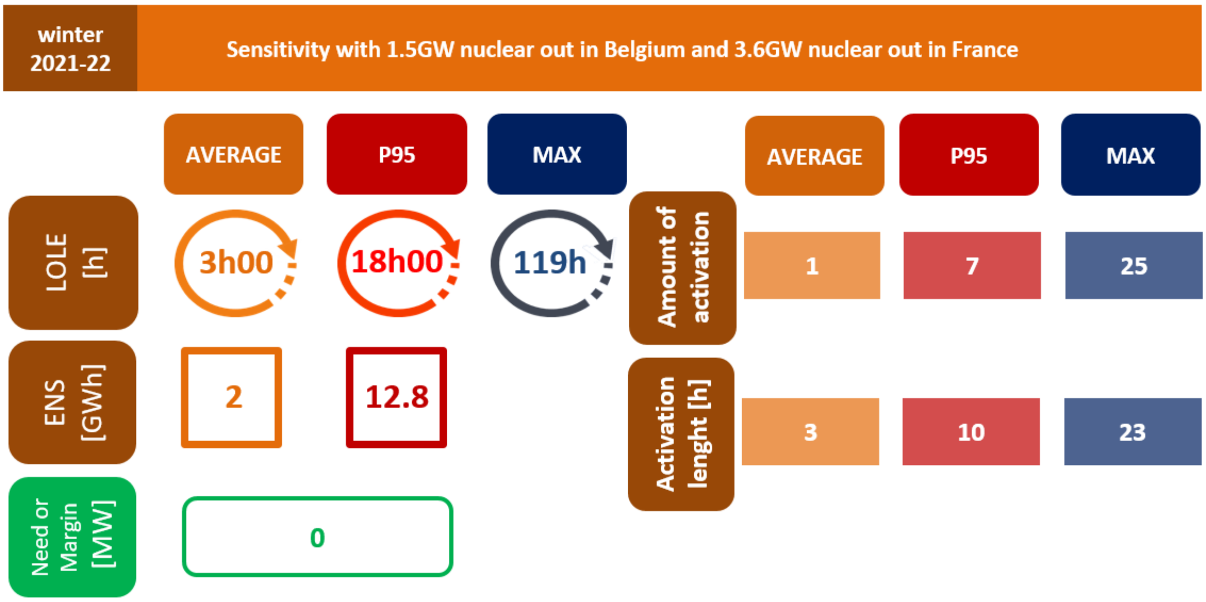


Figure 6.7

As can also be observed in Figure 6.7, the number of activations of a possible volume of strategic reserve would be low: **1 time** per year on average, **7 times** in P95 and **25 times** in the most extreme 'Monte Carlo' year simulated. The figure also indicates the maximum duration that a possible volume of strategic reserve is be activated without interruption. For the most extreme simulated event in all the future states, a possible volume would be activated for a maximum duration of **23 hours** without interruption. The average of the activation length is around **3 hours**. In the most extreme year simulated, **119 hours** of structural shortage were obtained. However, this is very rare, as shown by the P95 which is limited to **10 hours**. Furthermore, Figure 6.7 shows that the amount of energy not served (ENS) is limited to **2 GWh** over the winter on average and to **12.8 GWh** in P95.

6.2.3 Imports in periods of structural shortage

As for the 'base case' simulation, Belgium's and France's imports within CORE, during hours of ENS, are shown also here for the 'High Impact, Low Probability' scenario (see Figure 6.8). In this figure, each point represents one hour in which ENS is identified in Belgium. The graph shows imported energy for Belgium and France within CORE (resulting from the flow-based market coupling). The dots relate to the flow-based domains of the same colour. The depicted Belgian imports are lower than the maximum import. The constraint on maximum simultaneous import capacity therefore has no impact on Belgian adequacy as illustrated in Figure 6.9 since Belgium does not reach its maximum import capacity. Figure 6.8 shows two types of scarcity situations for Belgium. Some points are observed at the edge of the domain, showing the limit of the cumulative maximum import reachable for both France and Belgium. Other net position could be either due to a lack of energy within the modelled countries or by hitting constraints in one of the other 11 dimensions of the flow-based domain.

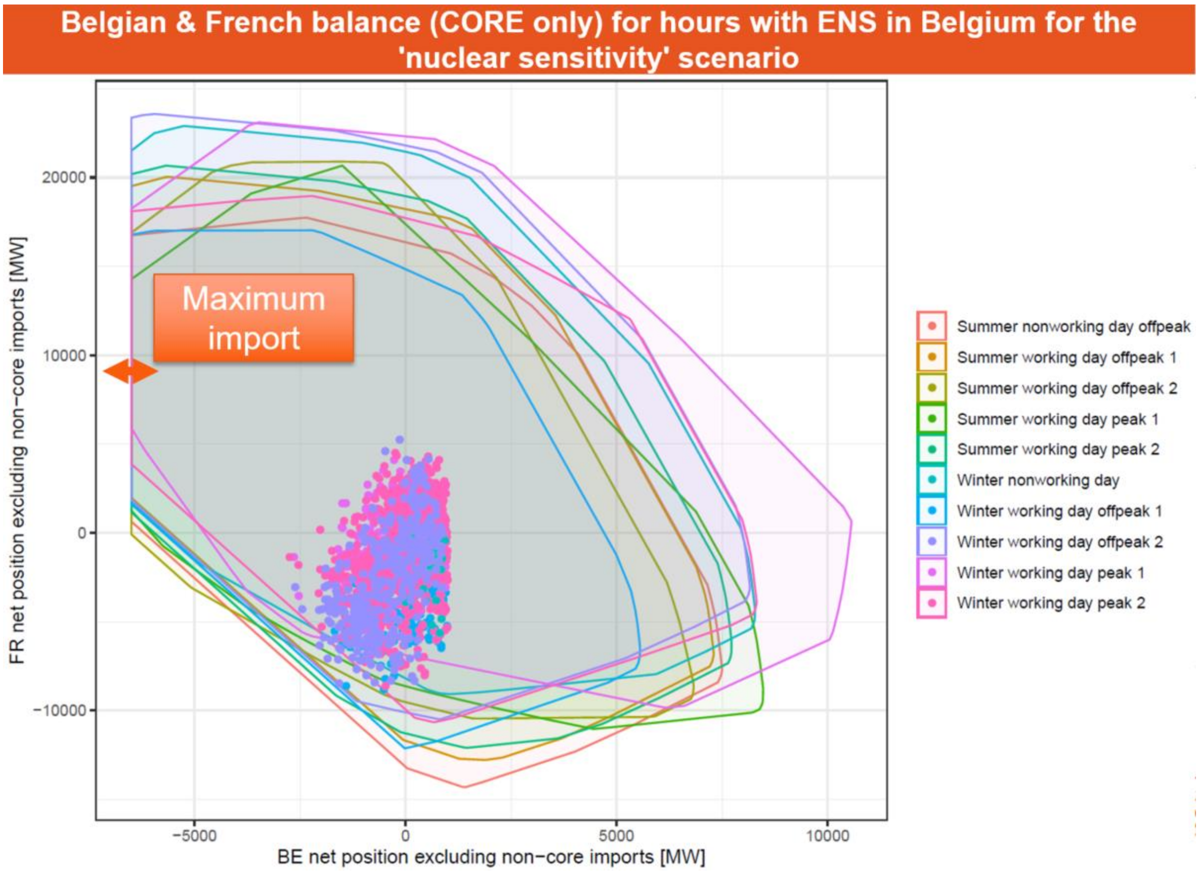


Figure 6.8

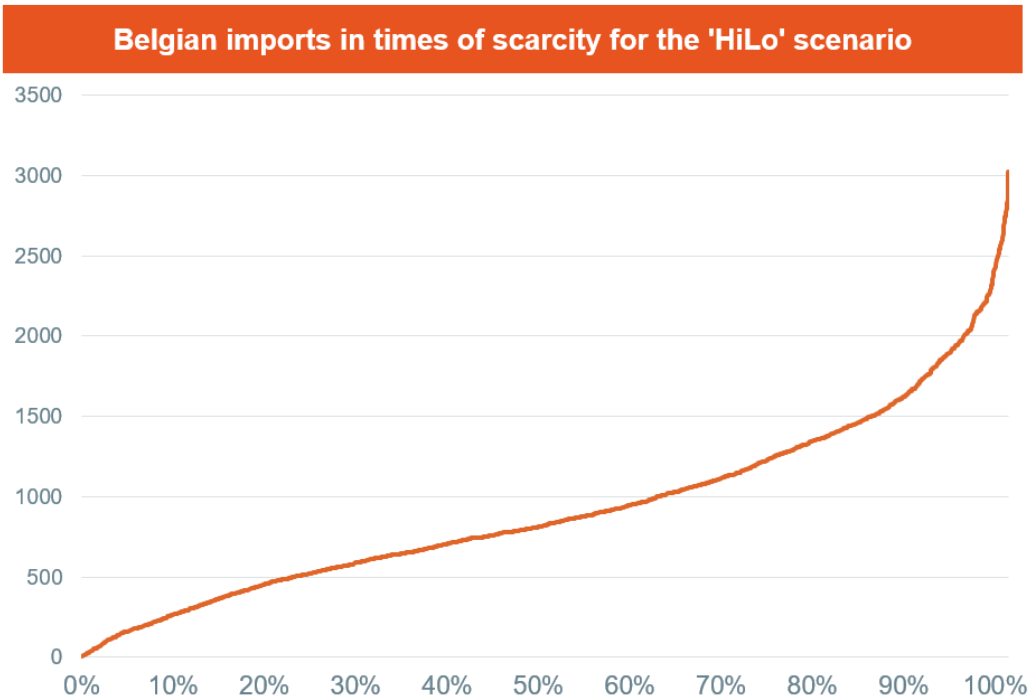


Figure 6.9

Figure 6.10 gives an idea of the countries that are in simultaneous scarcity with Belgium. If a neighbouring country is in simultaneous scarcity, their flag is shown. The percentage indicates how often the displayed combination is in simultaneous scarcity with Belgium. As can be seen in Figure 6.10, Belgium is rarely alone in scarcity and is almost always accopagnied by France. Additionally, Figure 6.10 shows that most of the times that Belgium is in scarcity, 3 or more other modelled countries are also in scarcity.

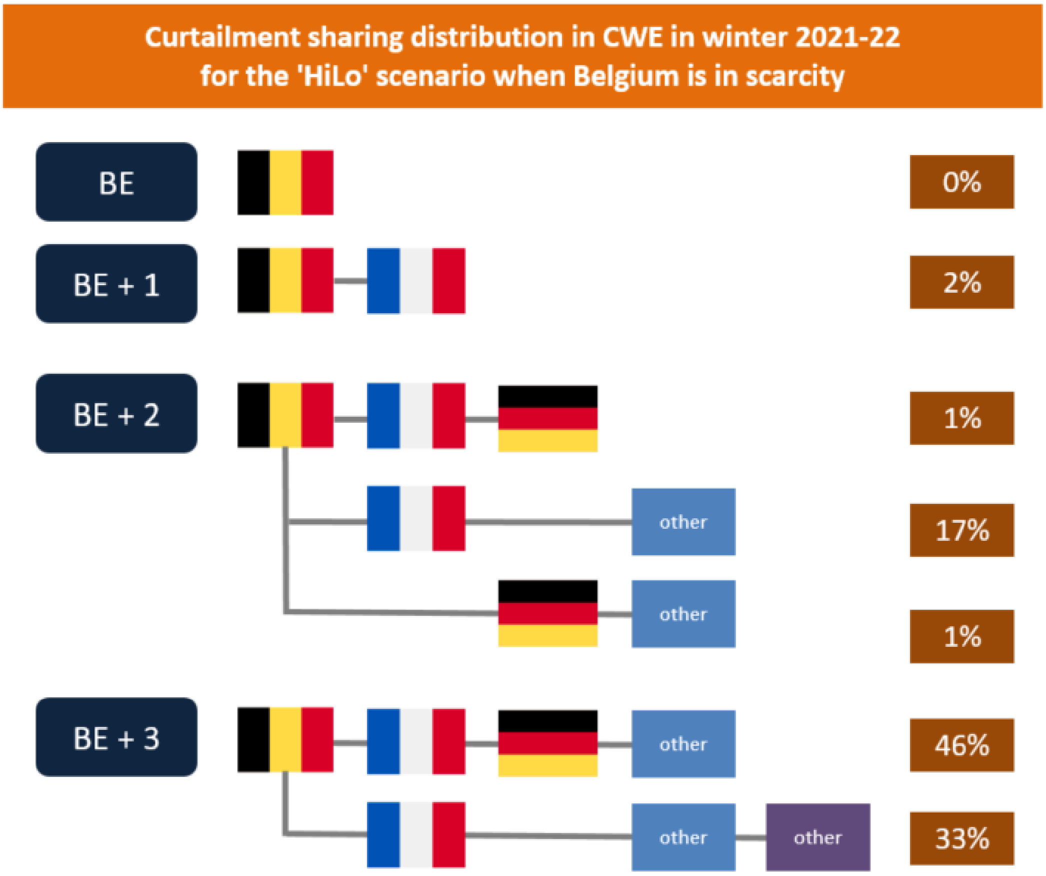


Figure 6.10

6.2.4 When is a structural shortage risk identified in the 'High Impact, Low Probability' scenario?

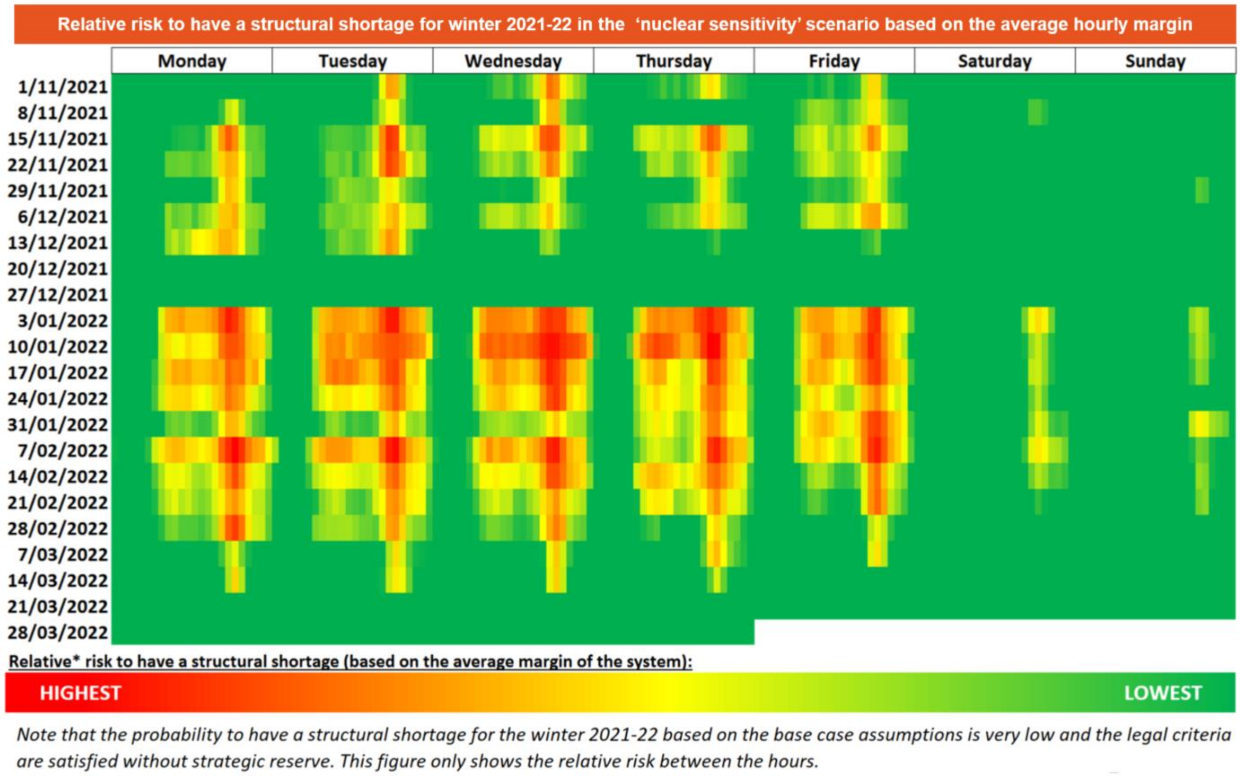


Figure 6.11

The risk of structural shortage for the 'high-impact low-probability' scenario has been calculated from the hourly remaining margin of the system, after taking into account all possible imports within CORE and via Nemo Link® (see Figure 6.11). This 'heat-map' chart is constructed for didactic purposes and makes it possible to clearly identify those times when the risk of structural shortage is the highest. The colour legend shows the relative risks (structural shortages are more likely to happen in hours that are coloured red than hours that are coloured green). In general, the risk follows the country's residual demand (demand minus non-dispatchable generation). Furthermore, effects such as weekdays, weekends, peak/off-peak hours and holidays can be derived from the figure.

From the hourly distribution of ENS depicted in Figure 6.12, it can be seen compared to the base case (Figure 6.3), there are more hours in which scarcity can occur. It can be seen that ENS is more distributed along the day and can also occur at hours other than the morning and evening peak-load hours. Nevertheless the two same main groups corresponding to the morning and evening peak can still be identified: a morning peak between 7 and 9 AM CET and an evening peak concentrating most of the observed ENS between 5 and 8 PM CET.

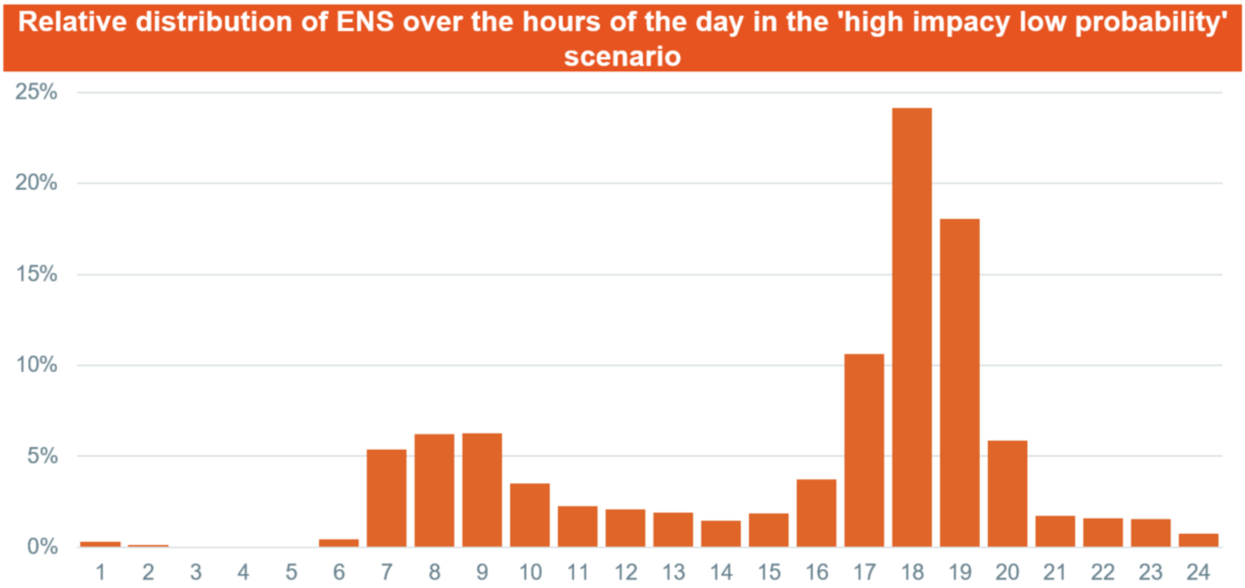


Figure 6.12

6.3 Results for winter 2022-23 'base case'

6.3.1 Changes in Belgian assumptions

The 'base case' for winter 2022-23 follows the assumptions presented in Chapter 3. The main changes for winter 2022-23 compared to winter 2021-22 are:

- Regarding the planned unavailabilities of the thermal park, the REMIT publication of planned outages during winter 22-23 is used as a reference. REMIT was monitored until 15 October 2020. For winter 2022-23, some planned unavailabilities are listed. Below, an exhaustive overview of those unavailabilities during the winter period, which have been taken into account for all the analysis performed, is provided:
  - ➢ DOEL 2: maintenance from 11/02/2023 until 25/03/2023 (inclusive)

The nuclear phase-out has been taken into account to the exact date of decommissioning of the individual units. For winter 2022-23 this means:
  - ➢ Decommissioning of DOEL 3 from 1 October 2022
  - ➢ Decommissioning of TIHANGE 2 from 1 February 2023
- Market response is taken into account in line with the results of the market response study and a progressive stance on growth rate (1275 MW for winter 2022-23);
- An increase in domestic renewable energy generation and storage facilities;
- A maximum simultaneous import capacity of 7500 MW is considered for Belgium in winter 2022-23. This simultaneous import capacity is imposed on the global Belgian import, i.e. import from CWE including the effect of ALEGrO and the flow through Nemo Link®.

6.3.2 Changes in the modelled region

- Following national policies, the net trend in terms of thermal generation capacity in Europe shows an overall decommissioning of approximately 16 GW, of which:
  - ○ -4 GW in DE constituting the last step of the nuclear phase-out;

  - -4 GW of coal and lignite in DE to reach the milestone of 30 GW by end 2022;
  - -4 GW in GB mainly due to the decommissioning of coal and nuclear power plants.
- On the other side the renewable capacity continues its progression along with the batteries and market response.
- The flow-based domain will be impacted by the progression towards the 70% minRAM target by 2025.

6.3.3 Calculation of LOLE, ENS

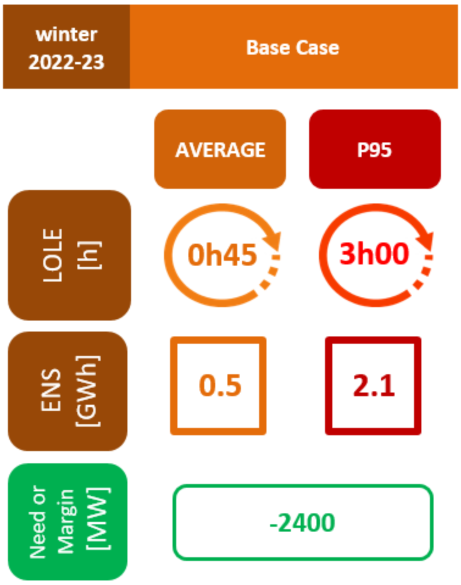


Figure 6.13

The resulting values are shown in Figure 6.13. The LOLE average for winter 2022-23 in the 'base case' is **45 minutes** and the percentile 95 is **3 hours**. These results are lower than the criteria defined by law, and the margin corresponding to the 2022-23 'base case' scenario is **2400 MW.** Furthermore, the amount of Energy Not Served (ENS) is **0.5 GWh** over the winter on average and **2.1 GWh** in P95.

6.4 Results for winter 2022-23 'High Impact, Low Probability' sensitivity

6.4.1 Description of the nuclear sensitivity

The sensitivity following the same logic as defined for winter 2021-22 (described in section 6.2.1) is analyzed in winter 2022-23. Therefore the 'High Impact, Low Probability' sensitivity will consist of 1.5 GW for the first part of the winter and 1 GW as of the decommissioning of Tihange 2 in Belgium and 3.6 GW for France.

6.4.2 Calculation of LOLE, ENS

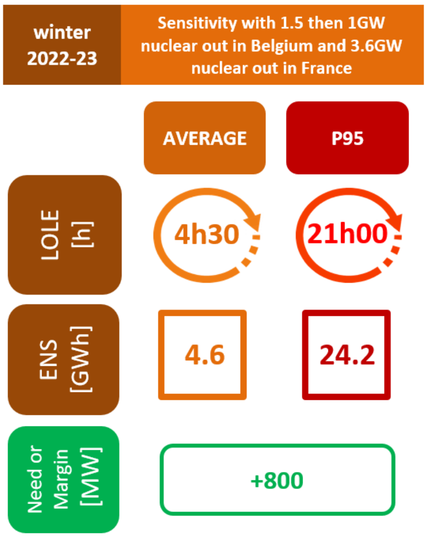


Figure 6.14

The resulting values for the 'High Impact Low Probability' scenario are shown in Figure 6.14. The LOLE average for winter 2022-23 in this sensitivity is **4 hours 30 minutes** and for the percentile 95 it is **21 hours**. These results are higher than the criteria defined by law and the resulting **need** corresponding to the 2022-23 'high-impact low-probability' scenario is **800 MW.** Furthermore, the amount of Energy Not Served (ENS) is calculated to be **4.6 GWh** over the winter on average and **24.2 GWh** in P95.

6.5 Results for winter 2023-24 'base case'

6.5.1 Changes in Belgian assumptions

The 'base case' for winter 2023-24 follows the assumptions presented in Chapter 3. The main changes of winter 2023-24 are:

- Regarding the planned unavailabilities of the thermal park, the REMIT publication of planned outages during winter 2023-24 is used as a reference. REMIT was monitored until 15 October 2020. Below, an exhaustive overview of those unavailabilities, which have been taken into account for this analysis, is provided: (as no planned outages were communicated yet for 2024, none are taken into account in this analysis)
  - TIHANGE 1N: maintenance from 21/10/2023 until 02/12/2023 (inclusive)
  - TIHANGE 1S: maintenance from 21/10/2023 until 02/12/2023 (inclusive)
- Market response is taken into account in line with the results of the market response study (1365 MW for winter 2023-24);
- An increase in domestic renewable energy generation and storage facilities;
- A maximum simultaneous import capacity of 7500 MW is considered for Belgium in winter 2023-24. This simultaneous import capacity is imposed on the global Belgian import, i.e. import from CWE including the effect of ALEGrO and the flow through Nemo Link®.

6.5.2 Other significant changes in the modelled region

- The next step in the evolution of the minRAM trajectory towards 70% will increase the size of the flow-based domains. On top of the increase of minRAM for both NL and DE, the grid model taken into account will only focus on cross-border CNECs starting in winter 2023-24.
- Net change in thermal capacity + 2 GW

  - The expected commissioning of new thermal generation (e.g. Flamanville in France, new gas capacity in GB + 3 GW…)
  - 2 GW coal decommissioning in DE
- The addition of renewable capacity and finally the expected increase of market response and batteries.
- The same unavailability as winter 2022-23 was considered for the French nuclear park as the information available on 15/10/2020 was not yet including the whole winter 2023-24.

6.5.3 Calculation of LOLE, ENS

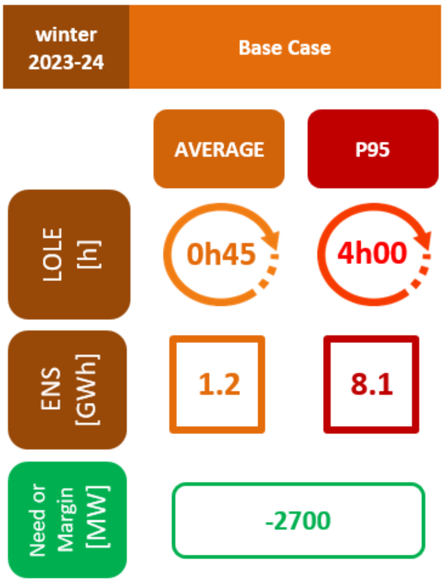


Figure 6.15

The resulting values are shown in Figure 6.15 . The LOLE average for winter 2023-24 in the 'base case' is about **45 minutes** and the percentile 95 is **4 hours**. These results are lower than the criteria defined by law, and the margin corresponding to the 2023-24 'base case' scenario is **2700 MW.** As in the previous winters, the margin ensures compliance for the average as well as for the percentile P95 LOLE indicator. Furthermore, the amount of Energy Not Served (ENS) is calculated to be **1.2 GWh** over the winter on average and **8.1 GWh** in P95.

6.6 Results for winter 2023-24 'High Impact, Low Probability' scenario

6.6.1 Description of the nuclear sensitivity

As explained in the 'High Impact, Low Probability' scenario defined in 6.4.1, a sensitivity of **1 GW** is applied in winter 2023-24 for Belgium and 3.6 GW for France.

6.6.2 Calculation of LOLE, ENS

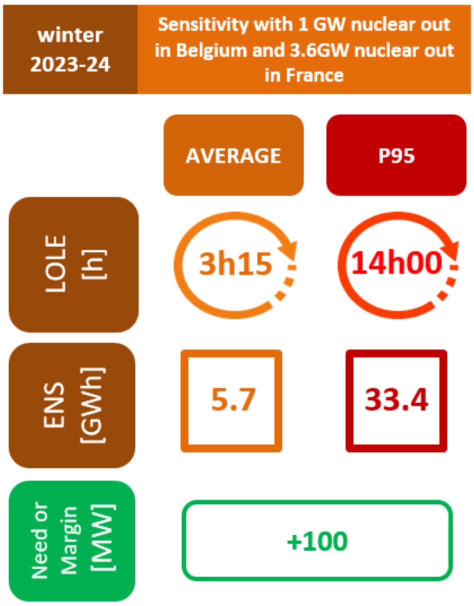


Figure 6.16

The results for the 'High Impact Low Probability' scenario are shown in Figure 6.16 for the sensitivity. The LOLE average for winter 2023-24 in this sensitivity is **3 hour and 15 minutes** and the percentile 95 is **14 hours**. The average LOLE results are higher than the criteria defined by law, and the **need** corresponding to the 2023-24 'high-impact low-probability' scenario is **100 MW.** Furthermore the amount of Energy Not Served (ENS) is on average **5.7 GWh** over the winter and **33.4 GWh** in P95.

7 Conclusions

This report gives an estimate of the required strategic reserve capacity in order to maintain Belgium's adequacy, in accordance with the criteria defined by law for winter 2021-22 and also provides an outlook for winter 2022-23 and winter 2023-24. In case no volume need is identified, the margin for each scenario is also calculated.
Elia performed a probabilistic analysis following the timetable set out in the legislation to allow the Federal Minister of Energy to make a decision on the volume needed by 15 January 2021.

The assumptions used in this report were defined in late October 2020, taking into account remarks received during the public consultation on the input data. The assumptions include the best available estimates for installed generation capacities in Belgium and neighbouring countries at the time of collecting the input.

Furthermore, according to Article 7quater of the Electricity Act, the Minister can review the volume for the strategic reserves no later than 1 September 2021 for winter 2021-22. Such a decision by the Minister will be based on an updated probabilistic analysis ('the Updated Analysis') by Elia with respect to the analysis performed and presented here. When preparing this Updated Analysis, Elia will exclusively take into account the following information, which is sufficiently relevant to the capacity and use of facilities for generation, storage, consumption or transmission of electricity, including planned or unplanned unavailability of these facilities, such as:

- any inside information duly published in accordance with Regulation 1227/2011 on wholesale energy market integrity and transparency;
- any concrete and relevant information which entails a formal commitment by a relevant entity and which is explicitly communicated by or on behalf of said entity to Elia;
- any information that the Minister explicitly requests Elia to take into account.

7.1 'Base case' scenario

The 'base case' scenario - as it is called in this study - describes the most likely situation regarding the Belgian generation facilities given the information that Elia collected. This scenario was discussed with the FPS Economy as required by law and was subject to a public consultation that ended on 21 September 2020.
The 'base case' scenario includes the following key assumptions:

- The economic projections of the Federal Planning Bureau from June 2020 were used to derive the total electricity consumption growth in Belgium. Such projections include a recovery of the consumption after the expected drop in 2020 following the Coronavirus disease (COVID-19) pandemic. The scenario results in a drop of -2.5% in electricity consumption for winter 2021-22 when compared to pre-COVID projections;

— In addition, in order to grasp the possible effect of the expected COVID-19 on the electricity consumption in the all the other modelled countries as well, the same reduction of -2.5% was applied for the winter 2021-22 on pre-COVID projections;
— Installed capacity forecasts for photovoltaic and onshore wind generation are based on the data from the regions, combined with a best estimate made by Elia and the FPS Economy about offshore wind generation are taken into account;
— With the expected go-live of the CORE flow-based (FB) market coupling mid-2021, commercial exchanges within the so-called CORE region will be allocated in the Day-ahead market using FB capacity allocation. In a first-of-its-kind improvement in adequacy assessments, Elia explicitly modelled these commercial exchanges (in the whole CORE region) using its flow-based methodology. In addition, non-CORE exchanges are also taken into account via their NTC;
— A maximum global simultaneous import capacity of 6500 MW for Belgium for winter 2021-22 is applied. This limit applies to the sum of imports from CORE and the flow on the Nemo Link® interconnector; this limit will increase to 7500 MW for the two subsequent winters thanks to the addition of voltage control elements;
— The latest public information (REMIT) regarding the planned outages of nuclear units (as set out on the transparency websites of the nuclear units' owners dated 15 October 2020) for Belgium and France is used. In addition to any planned outages, the 'base case' scenario takes into stochastically modelled Forced Outage rate. This rate is derived from the Forced Outages as witnessed over the last 10 years. 'Exceptional' outages are not covered by this normal Forced Outage rate, but are addressed separately in the 'High Impact, Low Probability' (HiLo) scenario described later;
— It is important to note that the COVID-19 has significantly impacted the maintenance and refuelling of France's nuclear power plants in 2020: the maintenance had to be rescheduled inducing a higher planned unavailability than historically observed for the upcoming winters.

For the 'base case' scenario in **winter 2021-22**, as defined in this report, the needed volume of strategic reserve is equal to 0 MW, as a **margin of 3300 MW** was obtained for Belgium.

For the 'base case' scenario in **winter 2022-23**, as defined in this report, the needed volume of strategic reserve is again 0 MW, as a **margin of 2400 MW** was obtained for Belgium.

For the 'base case' scenario in **winter 2023-24**, as defined in this report, the needed volume of strategic reserve is also 0 MW, as a **margin of 2700 MW** was obtained for Belgium.

7.2 'Sensitivity' to Belgian and French nuclear availability

To capture the consequences of 'high-impact, low-probability' events, an analysis of French and Belgian historical nuclear availability was conducted. From this analysis, it was observed that the modelled nuclear availability of the 'base case' scenario does not sufficiently take into account the unusual unavailability of Belgian and French nuclear units in recent winters. Therefore, the decision was made to perform a sensitivity analysis in which Belgian and French nuclear availability is aligned with the historical availability since 2012.
For Belgium, a sensitivity where 1.5 GW of nuclear production capacity is out of service for winter 2021-22 (on top of the normal forced outage rates and planned maintenance as mentioned above and simulated in the 'base case' model)

makes it possible to correctly align the modelled availability with the historical availability of the last seven winters. As this strategic reserve volume assessments coincides with the beginning of the nuclear phase-out in Belgium, the HiLo scenario for winter 2022-23 will be set at 1.5 GW for its first part and 1 GW as of the decommissioning of Tihange 2 on the first of February 2023, bringing the installed nuclear capacity close to 4 GW. For winter 2023-24, this rationale will be continued with a HiLo scenario of 1 GW for Belgium over the entire winter.
For France, the same analysis resulted in 3.6 GW of nuclear generation capacity considered unavailable for the entire winter (on top of the normal forced outage rates and planned maintenance as simulated in the 'base case' model for France), making it possible to correctly align the modelled availability with the historical availability of the last seven winters, as observed in France. For France the same volume of sensitivity has been used for all winters.

For this 'High Impact, Low Probability' scenario, as defined in this report:

- a **margin** of **0 MW** is obtained for Belgium in winter **2021-22**;
- the **need** for strategic reserve is **800 MW** for Belgium in winter **2022-23**;
- the **need** for strategic reserve is **100 MW** for Belgium in winter **2023-24**.

7.3 Overview of results

The results of the 'base case' scenario, as well as of the 'sensitivity' described above, are given in Figure 7.1 for the 3 analyzed winters.

It is important to note that the above results were obtained already assuming the development of additional RES, storage, market response, CHP or thermal generation in Belgium and abroad. For several countries, the additional amounts assumed in the study are significant and there is no guarantee that those would be realized in the future. Any changes in the assumptions can therefore have an impact on the calculated results.

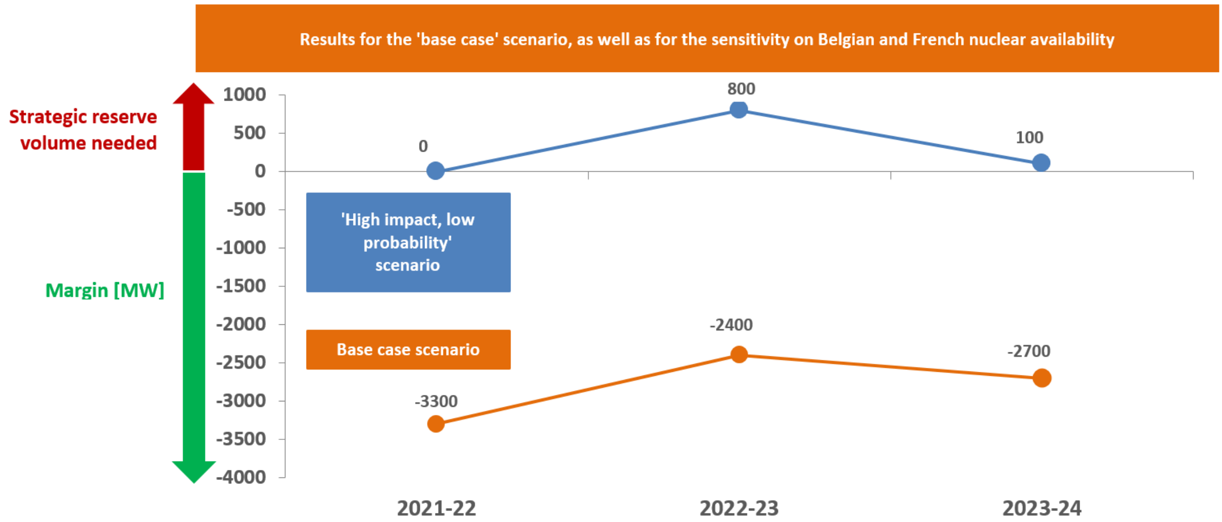


Figure 7.1

8 Appendices

8.1 Appendix 1: Simulation of the electricity market

This appendix provides a general overview of how the simulation of the electricity market was conducted for this analysis. In section 8.1.1, we elaborate on the construction of 'Monte Carlo' years, which serve as input for the actual simulation. Next, we describe in detail how the market simulation is conducted and we elaborate on the tool used in section 8.1.2.

8.1.1 Construction of the 'Monte Carlo' years

One way to perform a probabilistic risk analysis is through a so-called Monte Carlo analysis. The general idea of such a simulation is to sample in a statistically sound way a large number of possible future states. This combination of future states can then be analysed to determine adequacy indicators. We begin this section by indicating **which variables are sampled and how they are modelled** (section 8.1.1.1). Afterwards, section 8.1.1.2 elaborates on how the different variables are **combined into 'Monte Carlo' years**.

8.1.1.1 Variables taken into account for the simulation

There are two categories of sampled variables: climatic variables and the availability of the generation facilities.
There are **mutual correlations** between the following **climatic variables**:

- Time series for wind energy generation;
- Time series for PV generation;
- Time series for temperature (used to calculate the hourly time series for electricity consumption);
- Time series for hydroelectric power generation.

However, one variable is **not correlated** with the others, namely:

- The **availability of thermal generation facilities**.

The climatic variables in this study are modelled on the basis of 34 historical winters, namely those between 1982 and 2016. This data comes in the form of profiles for each of the 34 historical winters. As explained earlier, to capcture correctly the correlation between the climatic variables, these profiles are not mixed between years. The historical data for temperature, wind production, and solar production are procured in the context of ENTSO-E (the so-called PECD – Pan European Climate Database). These data are used *inter alia* in the ENTSO-E MAF (see section 1.7.3) and the ENTSO-E TYNDP market simulations. For the modelling of the hydroelectric power production, Elia based itself on the update to be used for the MAF 2020 study.

The climatic conditions are modelled using 34 (historical) climatic winters.

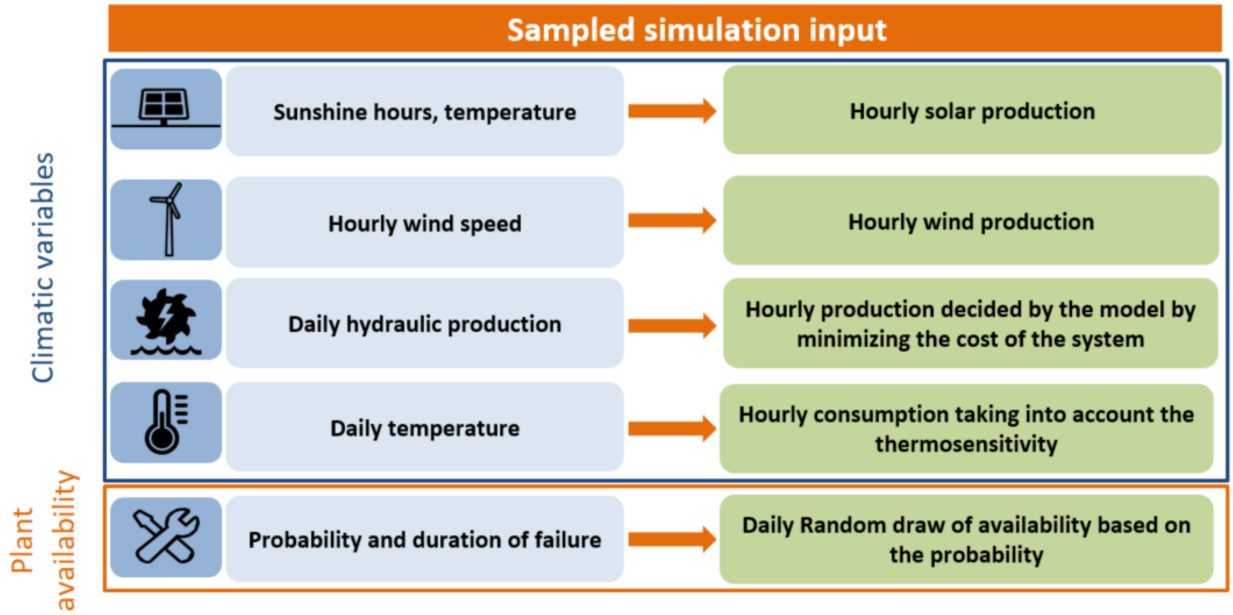


Figure 8.1

The availability data for Belgian **thermal generation** facilities comes from a historical analysis based on the years 2010 to 2019 (see section 3.1.3.2.2). For the other countries, the unavailability data come from the ENTSO-E studies [16], [22] and/or data from bilateral contacts with TSOs.

8.1.1.2 'Monte Carlo' sampling and composition of climatic years

The variables discussed in the previous section are combined so that the correlation between the various renewable energy sources (wind, solar, hydroelectric) and the temperature remains. Both **geographical** and **time correlations are present.**

Consequently, the climatic data relating to a given variable for a specific year will always be combined with data from the same climatic year for all other variables, with this applying to all countries involved.

In contrast, for **power plant availability, random samples** are taken by the model, by considering the parameters of probability and length of unavailability (in accordance with the 'Monte Carlo' method). This results in various time series for the availability of the thermal facilities for each country. Availability thus differs thus for each future state. Since each 'Monte Carlo' year carries the same weight in the assessment, the different availability samples have equal probability of occurrence.

What does the 'Monte Carlo' method do?

The '**Monte Carlo' method** is used in various domains, including **probabilistic risk assessments**. The name of this quantitative technique comes from the casino games in Monaco, where the outcomes for each game were plotted in order to forecast their possible results following a probability distribution translating the probability of winning.

In this same way, when a forecasting model is built, different assumptions are made by translating the **projections** of the future system states for which expected values have to be determined. In order to do this, the parameters linked to the system state, characterised by inherent **uncertainty**, are determined and for each of these an associated range of values through a specific distribution function is defined (see Figure 8.2).

The **deterministic approach** considers that a unique state is associated with each system input. This means that the same output will independently provide the number of times the simulation is performed since the same input is used.

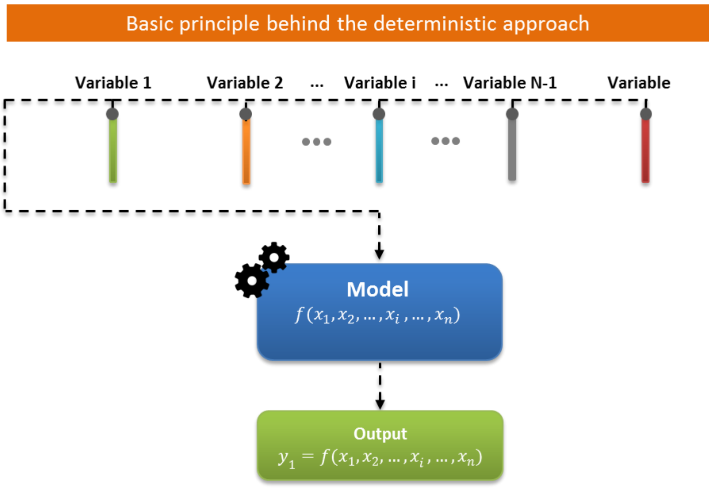


Figure 8.2

The '**Monte Carlo' method** extends the **deterministic method** in that it uses sets of random values as inputs, translating the uncertainty associated for these parameters thanks to a distribution function (or a large amount of samples of this distribution). This method is a class of computational algorithms and relies on repeated random sampling. This approach is used when analytical or numerical solutions do not exist or are too difficult to implement and can be described via four steps:

1. **Step 1:** Build a model characterised by parameters (inputs with inherent uncertainties) for the studied system

$$y = f(x_1, x_2, \dots, x_p)$$

2. **Step 2:** Generate a set of values for each input using a distribution function

$$Input = \{x_{1,i}, x_{2,i}, \dots, x_{p,i}\}$$

1) **Step 3:** Evaluate the model for a given set of values and store the output y_i
2) **Step 4:** Iterate steps 2 and 3 for i = 1 to N, where N represent the number of iterations

The **standard error** for the results arising from the 'Monte Carlo' method decreases with the square root of the sample size or $\mathbf{1/\sqrt{N}}$. In this assessment, random samples are taken for the unavailability of the thermal facilities of each country. Future states are determined by combining these samples with the time series for electricity consumption and for specific weather conditions. The simulations are conducted in relation to these future states (also referred to 'Monte Carlo' years). Figure 8.3 shows a random sample for p independent variables, yielding N different future states.

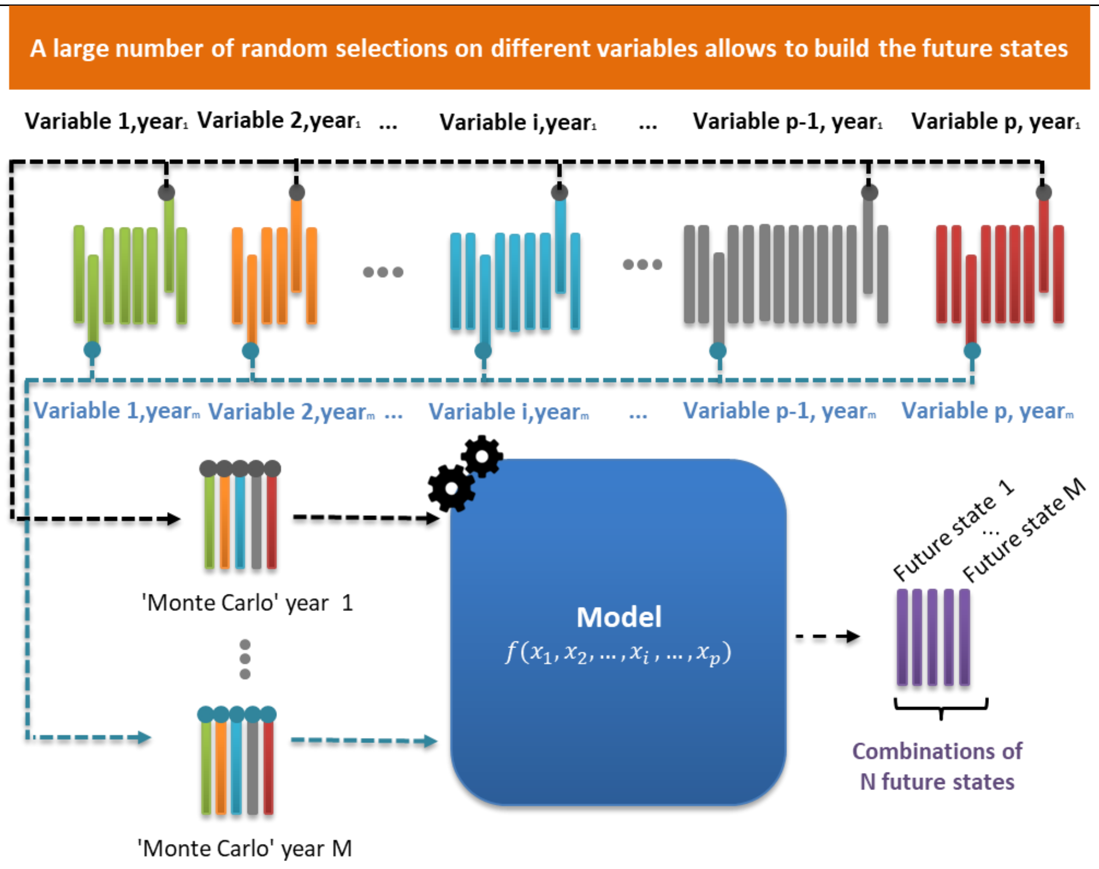


Figure 8.3

Number of future states

The number of future states that need to be calculated by the model to ensure the convergence of the results depends, among other things, on the variables, the simulated perimeter and the variability of the generation facilities. This study focuses on the two indicators determined by law, namely the average LOLE and the 95th percentile for the LOLE (LOLE95). These two parameters must converge enough to ensure reliable results. Depending on the scenario and level of adequacy, lower or higher amounts of 'Monte Carlo' years can be simulated.

Combining the results of all these future states yields the distribution of the number of hours of structural shortage.

8.1.2 Simulation of each 'Monte Carlo' year

To simulate the European electricity market, a number of assumptions and parameters must be established. These are detailed in Chapter 3 for Belgium and Chapter 4 for its neighbouring countries.

The **key input data** for each country are:

- the consumption profile and associated thermosensitivity;
- the installed capacity of the thermal generation facilities and the availability parameters;
- the installed PV, wind and hydroelectric capacity and associated production profiles based on the climate years;
- the **interconnections** (by using the flow-based methodology or fixed exchange capacity between countries (NTC method)).

These data are introduced by means of hourly or monthly time series or are established for a whole year.
A detailed modelling of the power plants' economic dispatch is performed. The assessment takes into account the power plants' marginal costs (see Figure 8.4) and also enables the pumped-storage power plants and hydroelectric reservoirs to be appropriately modelled.
Economic availability depends on the generation capacity available for the hour in question. The price in any given hour is determined by the intersection between the curve for supply (called the 'merit order') and demand. Demand is considered inelastic in this context. The market response to high prices is also taken into consideration, as explained in section 3.3 for Belgium.
Furthermore in the adequacy assessment, the model also correctly considers that in periods of structural shortage, all of the available generation facilities will be taken into account, operating at their maximum capacity in order to minimise the shortage.

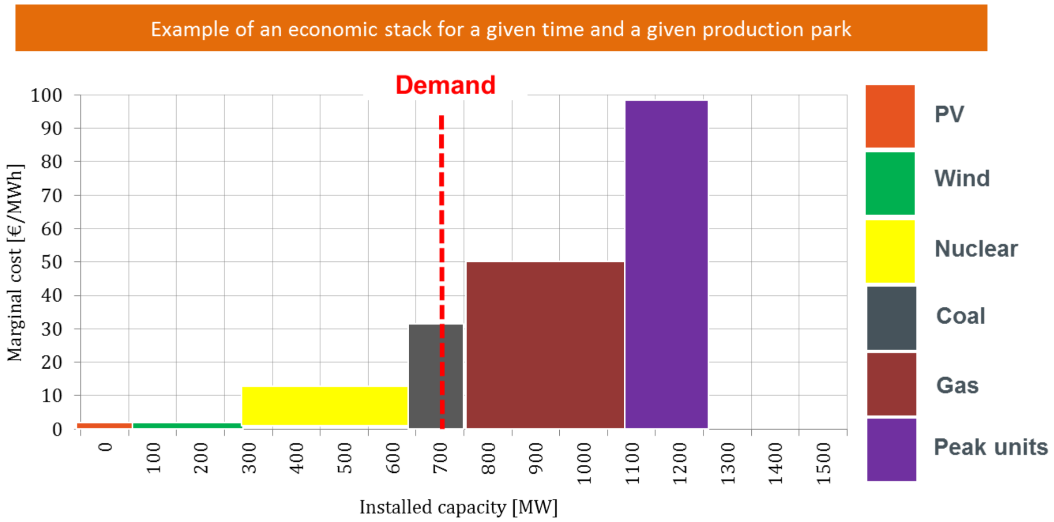


Figure 8.4

The **output of the model** that is assessed in this study consists of hourly time series showing the **energy shortage** for each country. These series can be used to deduce various indicators:
- the number of hours of structural shortage;
- the capacity surplus or shortage;
- the number of activations of the strategic reserve;
- Energy Not Served (ENS).

Other output data from the model are used to interpret the results:
- the level of generation for each type of power plant in each country;
- the commercial exchanges between countries;
- the availability of the power plants.

A host of other indicators can also be calculated, such as:
- the countries' energy balance (exports/imports);
- the use of commercial exchanges;
- the number of operating hours and revenues of the power plants;
- CO_2 emissions;

— the hourly marginal price for each country.

8.1.2.1 Model used to simulate the electricity market

The market simulator used within the scope of this study is ANTARES[22], a sequential 'Monte Carlo' multi-area simulator developed by RTE whose purpose is to assess generation adequacy problems and economic efficiency issues. This power system analysis software is characterised by these following specifications:

- representation of several interconnected power systems through simplified equivalent models. The European electrical network can be modelled with up to a few hundred of region-sized or country-sized nodes, tied together by edges whose characteristics summarise those of the underlying physical components.;
- sequential simulation with a time span of one year and a time resolution of one hour;
- 8760 hourly time series based on historical/forecast time series or on stochastic ANTARES generated times-series;
- for hydro power, a definition of local heuristic water management strategies at weekly, monthly and annual scales;
- a daily or weekly economic optimisation with hourly resolution

This tool has been designed to address:

1. generation/load balance studies (adequacy);
2. economic assessment of generation projects;
3. economic assessment of transmission projects.

A large number of possible future states can be extrapolated by working with historical or simulated time series, on which random samples are carried out in accordance with the 'Monte Carlo' method (see section 8.1.1.2). The main process behind ANTARES is summarised in Figure 8.5.

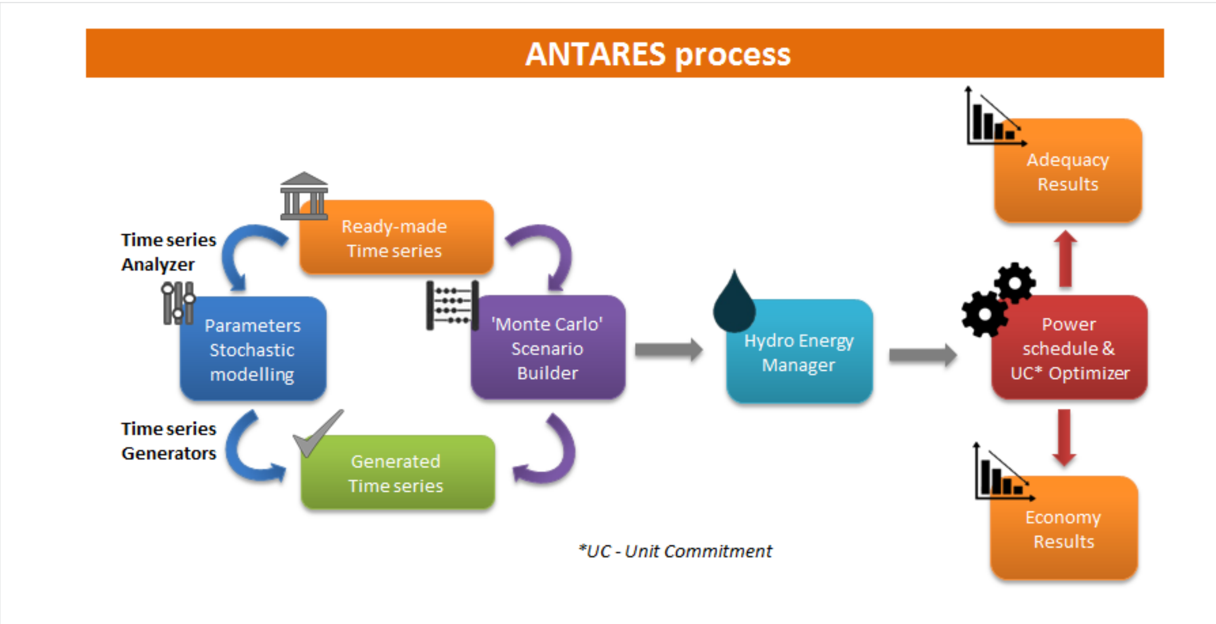


Figure 8.5

[22] ANTARES: A New Tool for Adequacy Reporting of Electric Systems

The simulation scheme behind this process can be described in 4 steps:

Step 1: Creation of annual time series for each parameter

For each parameter, **generation** or **retrieval** of **annual time series**, with an **hourly resolution** is needed (see Figure 8.6). The number of time series for each parameter is usually between 10 to 100 and can be increased if necessary.

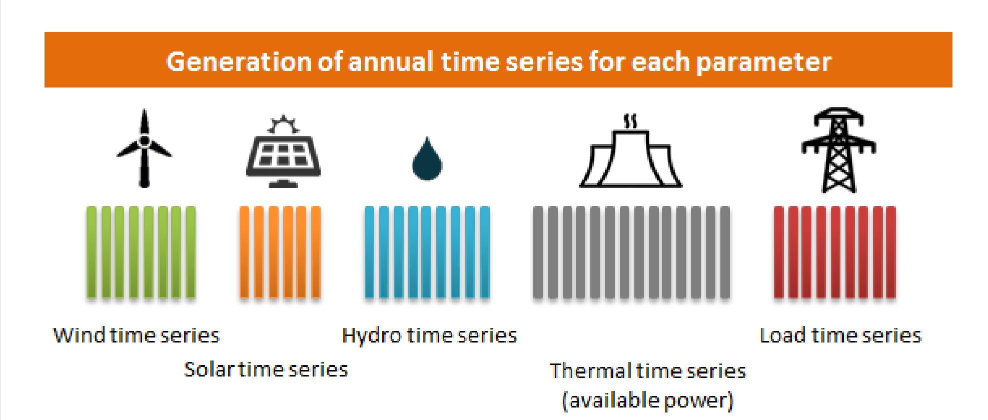


Figure 8.6

Step 2: Creation of a 'Monte Carlo' future state (year)

For each parameter, a **random selection** of the associated series is performed. This selection can also be made according to **user-defined** rules (**probabilistic/deterministic** mixes). The data selection process for each parameter provides an annual scenario called a 'Monte Carlo' year as shown in Figure 8.7.

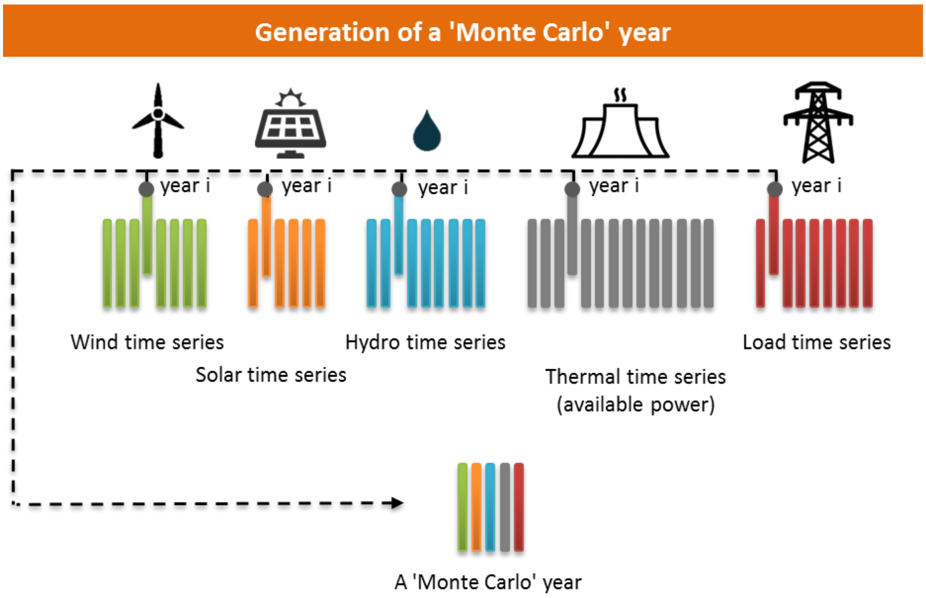


Figure 8.7

This process is repeated several times (several hundred times) in order to obtain a set of 'Monte Carlo' years representing a set of possible futures.

NB:

As described in section **8.1.1.2.**, the spatial correlations and the **correlation** between the various **renewable energy sources** (wind, solar, hydroelectric) and the **temperature** are modelled. In other words, this means a selection of wind, solar, hydroelectric production and thermo-sensitive consumption is performed for a **given year**, coming from one of the historical weather scenarios [12].

Step 3: Hydro storage energy management

The aim of this step is to assess and provide to the optimiser weekly hydraulic energy volumes to generate from the different reservoirs of the system, for each week of the current 'Monte Carlo' year. To perform this pre-allocation, the module breaks down annual and/or monthly hydro storage energy into weekly amounts, using a heuristic based on:

Net demand pattern (Load minus RES and must-run generation) calculated from scenario data;

Hydro management policy parameters: to define how net demand is weighted for energy dispatching from year to months and from month to weeks;

Reservoir rule curves: to define minimal and maximal curves in order to constrain the dispatching of hydro energy and to define the maximal power variation with the variation of the reservoir level.

Step 4: Power schedule and Unit Commitment (UC) optimiser

Two optimisation issues can be addressed in this process: adequacy or economy.
The **adequacy study** analyses whether there is enough **available generation power**, following the given state of the system, to meet **demand**, whatever the prices or costs involved. In other words**, no market modelling** is needed since the function that has to be minimised is the amount of load that has to be shed in the whole interconnected system. The **economy study** requires **market modelling** in order to determine which plants are delivering power at a given time. This process is carried out via the **economic dispatch** method, where the aim is to minimise the operating cost of the overall system by classically considering a 'perfect market' competition (market bids are based on short-term marginal costs) [10]. Because of the more refined analysis performed in the latter method, the **economy study** mode is the one used in this assessment.

ANTARES 'economy' mode aims to find the optimal economic dispatch of each hydro and thermal unit, in other words the one that minimises the total system costs taking into account generation constraints and possible energy exchanges. Because the 'value of lost load' (VOLL) in the study always exceeds the market clearing price the 'economy' mode will also minimise Energy Not Served, but it does this in a more realistic manner than what the 'adequacy' mode would generate.

The model is used in many European projects and national assessments:

- the PLEF adequacy study (see section 1.7.4);
- the e-Highway2050 study [48];
- ENTSO-E's TYNDP [23] [49] and MAF (see section 1.7.3);

[23] TYNDP: Ten Year Network Development Plan

— RTE French Generation Adequacy Reports [47].

Unit commitment (UC) and economic dispatch based on short run marginal costs

For each 'Monte Carlo' year, ANTARES calculates the most economical unit commitment and generation dispatch, i.e. the one that minimises generation costs while respecting the technical constraints of each generation unit. Dispatchable generation (including thermal and hydro generation) and interconnection flows constitute the decision variables of an optimisation problem whose objective function is to minimise the total operational costs of the system. The optimisation problems are solved with an hourly time step and a weekly time-frame, assuming perfect information at this horizon, but assuming that the change in load and RES is not known beyond that. Fifty-two weekly optimisation problems are therefore solved in a row for each 'Monte Carlo' year. The modelling adopted for the different assets of the system is briefly described below.

Grid topology

The topology of the network is described with areas and links. (In this study, one area represents a country). It is assumed that there is no network congestion inside an area and that the load of an area can be satisfied by any local power plant.

Each link represents a set of interconnections between two areas. The power flow on each link is bound between two Net Transmission Capacity (NTC) values, one for each direction.

Moreover, in ANTARES, some binding constraints on power flows can be introduced. They take form of equalities or inequalities on a linear combination of flows. For instance, they have been used to model flow-based domains in the CWE market-coupling area.

Wind and solar generation

Wind and solar generation are considered as non-dispatchable and comes first in the merit order. More precisely, as other non-dispatchable generation, they are subtracted from the load to obtain a net load. Then, ANTARES calculates which dispatchable units (thermal and hydraulic) can supply this net load at a minimal cost.

Thermal generation

For each node, thermal production can be divided into clusters. A cluster is a single power plant or a group of power plants with similar characteristics. For each cluster, in addition to the time series of available capacity, some parameters necessary for the unit commitment and dispatch calculation are taken into account by ANTARES:

- the number of units and the nominal capacities, defining the installed capacities;
- the cost, including marginal and start-up cost;
- the technical constraints for minimum stable power, must-run, minimum up and down durations.

Concerning the technical constraint for must-run, two values can be used: a value considered only if the plant is switched on (minimum stable power) and a value which, if higher than 0, forbids the plant from being switched off in the dispatch (must-run). The latter is given on an hourly step time base, whereas the former is a single value for the whole simulation.

Hydro generation

Three categories of hydro plants can be used:

- **Run-of-river** (**RoR**) plants which are non-dispatchable and whose power depends only on hydrological inflows;
- **Storage plants** which possesses a **reservoir** to defer the use of water and whose generation depends on inflows and economic data;
- **Pumped-storage station (PSP**) whose power depends only on economic data.

Run-of-river generation is considered as **non-dispatchable** and comes first in the merit order, alongside wind and solar generation.

For storage plants, the annual or monthly inflows are first split into weekly amounts of energy (see step 3 in section 8.1.2.1). The use of this energy is then optimised over the week alongside the other dispatchable units. Each hydro unit can generate up to its maximum capacity.

Pumped-storage plants can pump water which is stored and turbined later. It is operated on a daily or weekly basis, depending on the size of its reservoir. ANTARES optimises the operation of PSP alongside the other dispatchable units while making sure that the amount of energy stored (taking into account the efficiency ratio of the PSP) equals the amount of energy generated during the day/week.

Demand response

One way of modelling demand response in the tool is by using very expensive generation units. Those will only be activated when prices are very high (and therefore after all the available generation capacity is dispatched). This makes it possible to replicate the impact of market response as considered in this study. Activations per day and week can be set for this capacity as binding constraints.

8.2 Appendix 2: Adequacy parameters

Some parameters in the rules governing the functioning of the strategic reserve[24] are based on the results of the simulations conducted in this adequacy study. They are:

- **A.** Maximum activation limits of strategic reserve (SR) units
- **B.** Expected activation time of SR units
- **C.** Required availability criteria for strategic demand-side response (SDR)
- **D.** Equivalence factor for SDR

The parameters A, C and D are traditionally based on a scenario where there is a need for strategic reserves, with a substantial amount and duration of activations in order to cope with the inherent uncertainty in future real-time situations. For this reason, these parameters should not be too constrained ex ante in terms of the number of SR activations as the certification and selection of SDR (taking into account the availability rate and the equivalence factor) has to guarantee SDR availability when most needed. For this reason, it uses the 'Sensitivity with 1.5 GW nuclear out in Belgium and 3.6 GW out in France' scenario.

In contrast, parameter B is linked to the expected average number of activations to provide a realistic estimation of the expected activation costs of different providers and ensure a fair selection process. For this reason, it uses the most realistic scenario, i.e. 'base case'.

8.2.1 Parameter A: Maximum activation limit of SR units

The contract with strategic reserve providers specifies a maximum amount of activation, as well as a maximum cumulative duration of delivery requested by Elia during the winter period covered by the SR contract. These parameters are determined by the observed SR activations in the simulation of 'Sensitivity with 1.5 GW nuclear out in BE and 3.6 GW out in FR' scenario for which the results are depicted in Figure 8.8.

- The maximum amount of activations 'MAX' is used to determine the maximum number of activations during the winter period and is equal to **25**.
- The 'MAX' LOLE (h) is used for the cumulative maximum duration in hours of the annual delivery and is equal to **119 hours.**

[24] The functioning rules, subject to a public consultation and approval by the national regulatory authority, specify the rules for the procurement, reservation and activation of the strategic reserve.

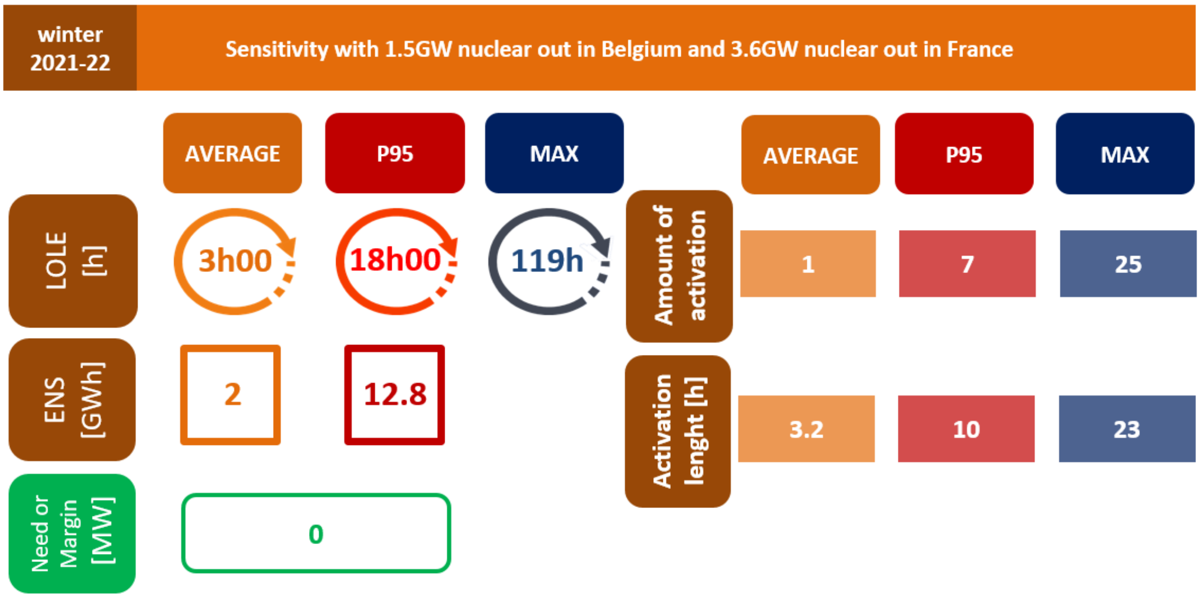


Figure 8.8

8.2.2 Parameter B: Expected activation time of SR units

The technical and economic criteria used to select the SR units to be contracted are based, amongst other things, on three parameters resulting from this adequacy study. These parameters are determined by the observed strategic reserve activations in the simulation of the 'base case' for which the results are depicted in Figure 8.9.

- #Actcold: the number of activations in the winter period that do not begin within 24 hours after the end of a previous activation. This number will be based on the average amount of activations (rounded up to the next integer) and is set at 1.
- #Acthot: the number of activations during the winter period that begin within 24 hours of the end of another activation. This number will be based on the average amount of activations (rounded up to the next integer) and is set at 1.
- Actduration: cumulative duration of activation during the winter period. This number will be based on the average LOLE(h) (rounded up to the next integer) and is set at 1.

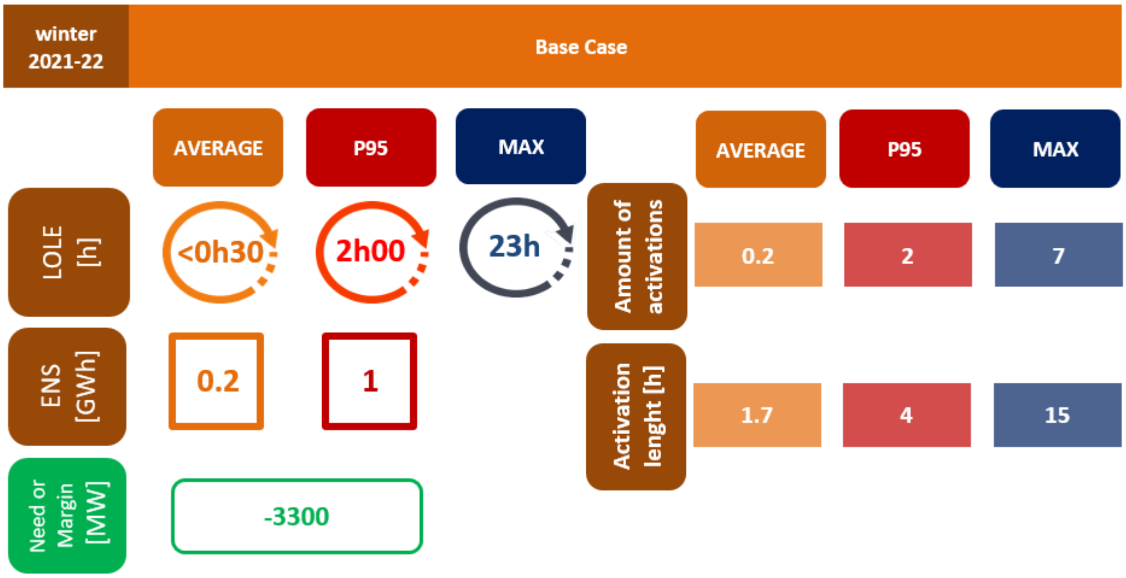


Figure 8.9

8.2.3 Parameter C: Required availability criteria for SDR

A certification procedure takes place to ensure that the contracted strategic reserve capacity provided by demand response is available during periods of system stress. This procedure will determine the minimum availability criteria that have to be met in order to be certified as capacity which can be offered as strategic demand response in the tender. These criteria are differentiated according to time of day, type of day and month. In its tendering procedure, Elia analyses the candidate supplier's historic consumption profile according to these criteria.

The criteria are set based on the risk of scarcity resulting from the average available margin (visualised by the heat map in Figure 8.10) in the 'Sensitivity with 1.5 GW nuclear out in BE and 3.6 GW out in FR' scenario (Figure 8.8).

The average available margin gives the MWs still available for each hour of the winter period after demand has been met, after averaging the results for all of the simulated 'Monte Carlo' years.

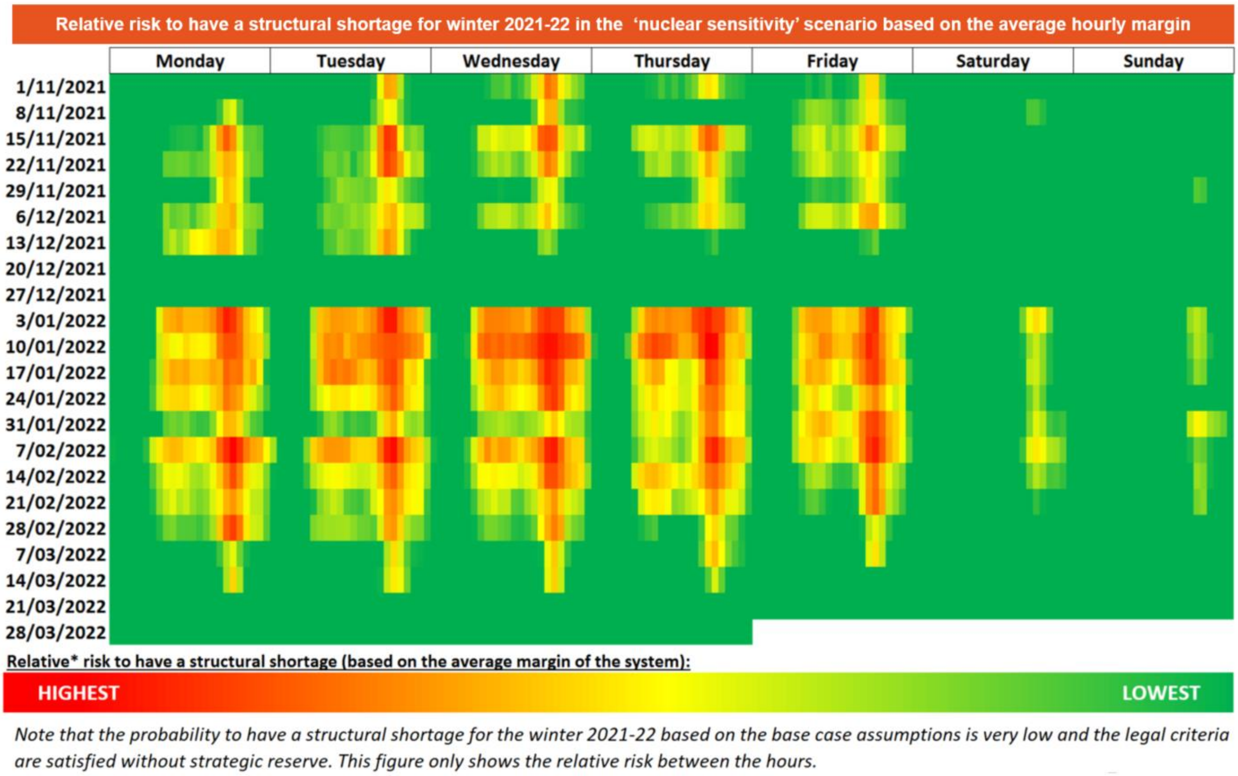


Figure 8.10

To ensure representative datasets, the heat map is translated into a certification table of categories each with a minimum availability criterion expressed as a percentage. This is based on a linear interpolation in which the lowest generation margin corresponds to an availability of 100% and the highest to an availability of 0%. These availability levels are then grouped into categories, each containing periods with similar availability levels. The certification will then determine the maximum capacity that a given candidate supplier can offer based on its consumption profile (e.g. ensuring 85% availability over all hours marked with an 85% criterion). Note that the functioning rules may also set out additional criteria not related to the adequacy study, such as availability during high-price periods.

8.2.4 Parameter D: Equivalence factor for SDR

The equivalence factor (EF) is used to take account of the limitations in SDR activation time (constrained by an activation length of 4 or 12 hours, compared to no limitations for SGR[25]) and to calculate an 'equivalent volume' for each SDR bid so that SDR bids can be placed in competition with SGR bids on the same basis of comparison. 1 MW SDR is therefore considered equivalent to 1MW*EF of strategic reserve.

The EF is calculated as

$$LOLE_{SGR/SDR} \ / \ LOLE_{SGR} = 100\% - (LOLE_{SGR} - LOLE_{SGR/SDR}) \ / \ LOLE_{SGR}$$

[25] SGR: strategic generation reserve

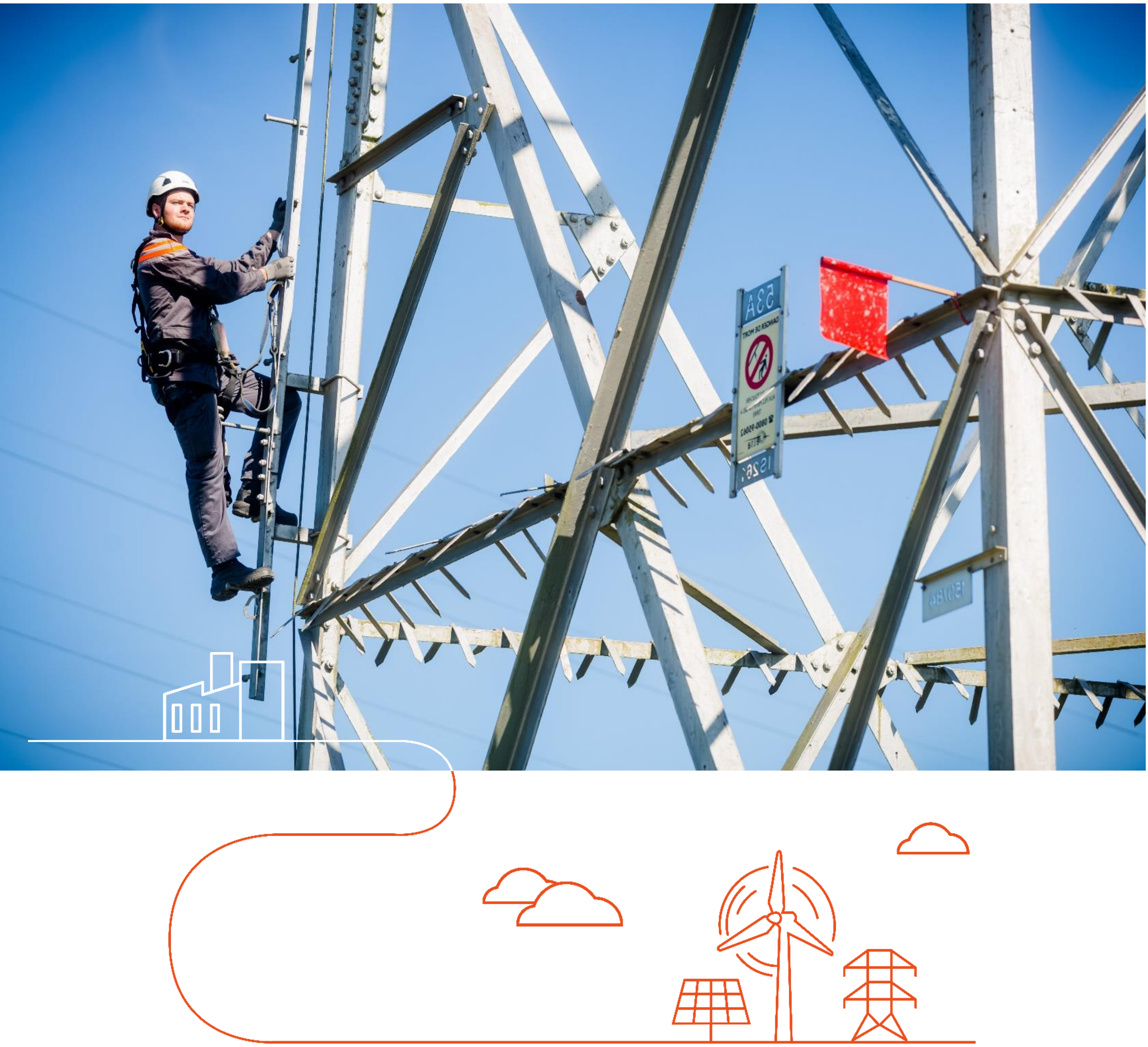
The equivalence factor is therefore equal to the ratio between the reduction in the average LOLE hours (= LOLE gain) that a given volume X generates from SDR and the LOLE that would have ensued if volume X had been met by SGR. In this context, X is varied between 0 and the total necessary volume of strategic reserve.

For this calculation, the 'Sensitivity with 1.5 GW nuclear out in BE and 3.6 GW out in FR' scenario (Figure 8.10), should be used. Since no need for strategic reserve is identified in this scenario, the calculation of the equivalence factor is considered as non-applicable here.

Position of the offer (Poffer) with respect to the total SDR volume offered, ranked by increasing price	**Equivalence factor[26]**
Poffer ≤ 200 MW	N.A.
200 MW < Poffer ≤ 400 MW	N.A.
400 MW < Poffer ≤ 600 MW	N.A.
600 MW < Poffer	N.A.

[26] A calculation of the equivalence factor will be performed, should the volume of SR be revised by the Minister before 1 September 2021, and should the revised volume in this case be higher than 'zero' MW.

9 Abbreviations



ACER: agency for the cooperation of energy regulators

aFRR: automatic frequency-restoration reserve

ANTARES: a new tool for adequacy reporting of electric systems

ARP: access responsible party

BP: Bilan Prévisionnel

BRP: balance responsible party

CACM: capacity allocation and congestion management

CC: capacity calculation

CCGT: combined-cycle gas turbine

CEER: council of European energy regulators

CEP: clean anergy for all Europeans package

CfD: contracts for difference

CHP: combined heat and power

CIPU: contract for the injection of production units

CM: capacity Market

CNEC: critical network element and contingency

COVID-19: Name for the disease caused by the SARS-CoV-2 (2019-nCoV) coronavirus.

CPF: carbon price floor

CRE: commission de regulation de l'énergie – the French energy regulator

CREG: Commission for Electricity and Gas Regulation

CWE: Central West Europe

DA: day-ahead

DG: Directorate-General

DSO: distribution system operator

EEAG: European Economic Advisory Group

EF: equivalence factor

EMR: electricity market reform

ENS: energy not served

ENS95: energy not served for a statistically abnormal year (95th percentile)

ENTSO-E: European Network of Transmission System Operators for Electricity

EPR: European pressurised-water reactor

ERAA: European Resource Adequacy Assessment

FB: flow-based

FBMC: flow-based market coupling

FCR: frequency containment reserve

FES: future energy scenario

FOR: forced outage rate

FPB: Federal planning bureau

FPS: Federal Public Service

FRR: frequency restoration reserve

GT: gas turbine

GU: grid user

HTLS: high-temperature low sag – a type of electrical conductor

HVDC: high-voltage direct current

IA: impact assessment

LOLE: loss-of-load expectation

LOLE95: loss-of-load expectation for a statistically abnormal year (95th percentile)

LOLP: loss-of-load probability

LWR: least worst regret

MAF: mid-term adequacy forecast

mFRR: manual frequency restoration reserve

minRAM: minimum remaining available margin

NEP: Netzentwicklungsplan – the german grid development plan

NTC: net transfer capacity

PLEF: pentalateral energy forum

PST: phase-shifting transformer

PTDF: power transfer distribution factor

PV: photovoltaic

RAM: remaining available margin

REMIT: Regulation on Wholesale Energy Market Integrity and Transparency

RES: renewable energy sources

RoR: run-of-river

RSS: really simple syndication

RTE: Réseau de Transport d'Electricité (French transmission system operator)

SDR: strategic demand reserve

SGR: strategic generation reserve

SPAIC: standardised procedure for assessing the impact of changes

SR: strategic reserve

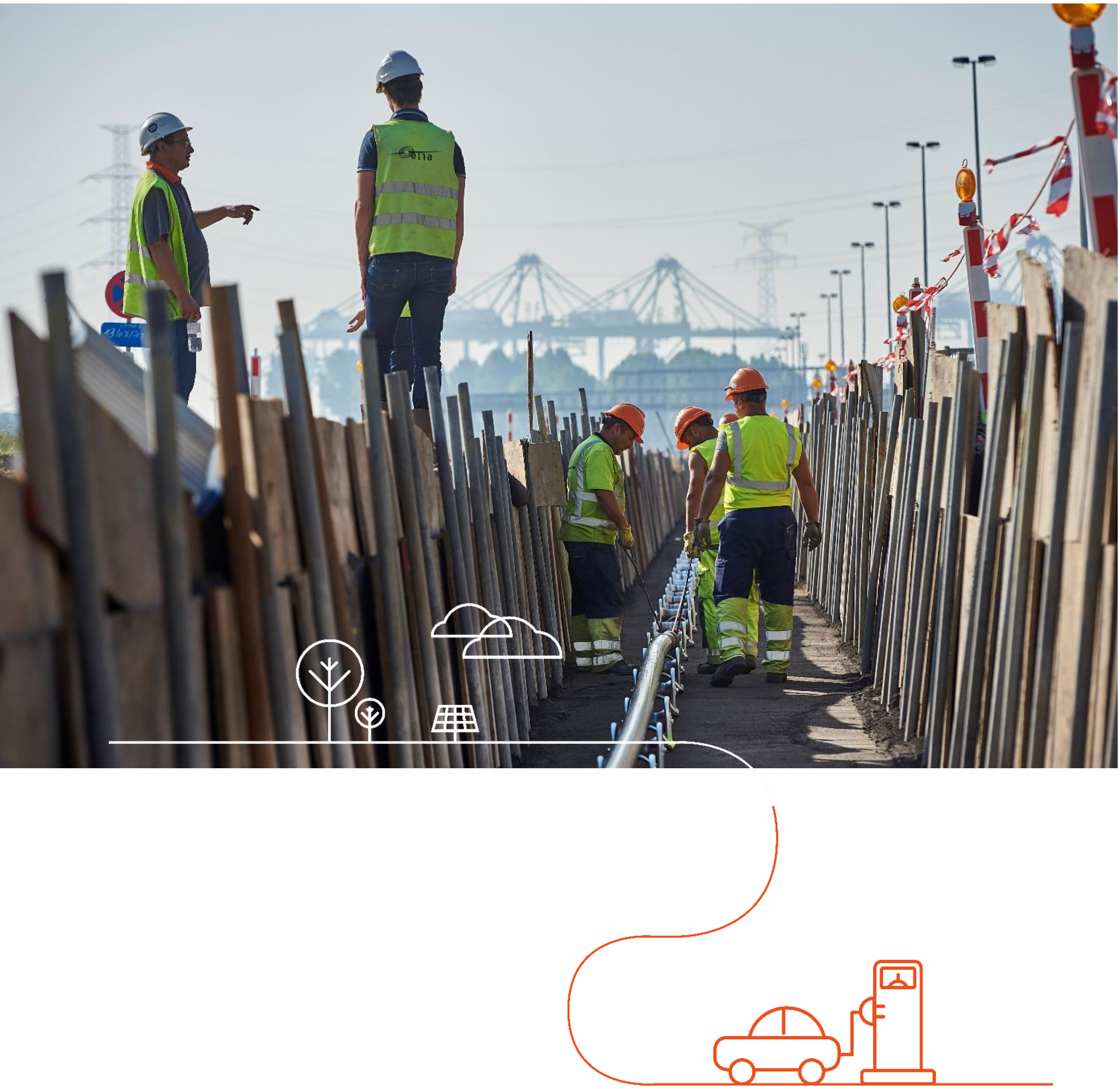
TSO: transmission system operator

TYNDP: ten-year network development plan

UC: unit commitment

UK: United Kingdom

10 Sources



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