The need for a **strategic reserve** for **winter 2020-21**

and winter outlook for 2021-22 and 2022-23

November 2019

Contents

Executive Summary

In accordance with the Belgian Electricity Act, 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 (2020-21) must be taken by 15 January 2020 at the latest.

This report provides a probabilistic assessment of Belgium's security of supply for next winter (2020-21) 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. This approach was approved by the European Commission's DG Energy within the context of a state aid review of the strategic reserve mechanism. This report also gives a preliminary outlook on the need for a strategic reserve for subsequent winters in 2021-22 and 2022-23.

'Base case' scenario

Assumptions

The 'base case' scenario includes the following assumptions (only the main drivers for Belgium are listed below):

— a growth of 0.4% per year in Belgium's total electricity demand;

— 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 2019) for Belgium and France. In addition to any planned outages, the 'base case' scenario takes into account a normal 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 below;

— installed capacity forecasts for photovoltaic and onshore wind generation based on the latest data from the regions, combined with a best estimate made by Elia and FPS Economy about offshore wind generation;

— commercial exchanges between Belgium and the other CWE countries are modelled using available flow-based domains, modified to take into account full grid availability in Belgium, the HTLS upgrades, the ALEGrO interconnector and incorporating the effects of the German-Austria (DE-AT) split, in effect since 1 October 2018;

— the availability of the new interconnectors with Great Britain (Nemo Link®) and Germany (ALEGrO), each having a capacity of 1000 MW;

— a maximum global simultaneous import capacity of 6500 MW for Belgium for winter 2020-21. This limit applies to the sum of imports from CWE and the flow on the Nemo Link® interconnector;

- a stable trend in installed thermal generation facilities in Belgium with the most significant changes being the return of the Vilvoorde power plant to the market as OCGT and the closure of the AWIRS biomass power plant.

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 – has a potential 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.

Conclusion

The 'base case' scenario in this probabilistic assessment for next winter (2020-21) leads to a margin of 3200 MW, with an average LOLE 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 2020-21 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 our calculations are based on historical unplanned unavailability over the last 10 years. Unusual, long-lasting outages that occurred between 2012 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 regard to assessing Belgian adequacy. A sensitivity analysis of nuclear availability, both in Belgium and France, proves a more robust approach for assessing a volume need for the strategic reserve. This approach has been approved by the European Commission's DG Energy within the context of a state aid review of the strategic reserve mechanism.

Additional sensitivity

However, 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' to the real 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 already considered in the 'base case' and the simulated Forced Outages.

Situation in France

Likewise, the unavailability of the French nuclear generation fleet has an important impact on the adequacy situation in Belgium, as seen 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, the same analysis applied to Belgium was conducted for the French nuclear availability.

Similar to Belgian nuclear generation capacity, studies have compared the modelled French nuclear availability in the 'base case' scenario with the real French nuclear availability showing that in a 'High Impact, Low Probability' scenario a capacity reduction 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 and the Forced Outages already considered in the 'base case' for France.

Conclusion

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 2020-21 in order to meet the legal criteria. The 'High Impact, Low Probability' scenario in the study leads to a margin of 100 MW.

This conclusion reflects a worsening of the situation for Belgium compared to the preliminary outlook in the November 2018 strategic reserve volume report for winter 2020-21, which is mainly due to the accelerated decommissioning of conventional generation in neighbouring countries. This acceleration was already highlighted in the context of the 'Adequacy and Flexibility Study' that Elia published in June 2019.

However, this result is inseparable from the hypotheses considered, for Belgium as well as for neighbouring countries. Specifically regarding Belgian nuclear generation units, it is important to note that:

- the assumptions made regarding the planned unavailability of the Belgian generation fleet are based on the latest information on the relevant market transparency channels (REMIT);
- regarding the specific long-lasting outages of certain nuclear generation units over the last years, Elia adopted a sensitivity approach. For Belgium this leads to an additional 1.5 GW reduction in Belgian nuclear generation capacity.

The chosen scenario results in a nuclear generation fleet for Belgium for which:

- 1 GW is unavailable due to planned maintenance on Tihange 2 from 7 November 2020 to 18 December 2020;
- 0.5 GW is unavailable due to planned maintenance on Doel 2 from 27 February 2020 to 9 April 2020;
- 1.5 GW is taken out of service for the entirety of winter 2020-21;
- Additionally, Forced Outages of the remaining nuclear units are statistically simulated at a rate of 3.4%, which is based on historical unplanned unavailability during the last 10 years, excluding long-lasting outages which are covered in the previous bullet point.

There is a two-month buffer between planned outage end dates for Doel 3 and Tihange 1 and the start of winter 2020-21. However, an extensive planned outage of Tihange 3 is scheduled to take place from 7 June 2020 to 24 October 2020, meaning no buffer exists between the end of the last maintenance period before winter, as planned today by the generation units' owners, and the start of winter 2020-21. The risk of a delay in the planned outage strengthens Elia's recommendation to make a decision based on the 'High Impact, Low Probability' scenario.

Needless to say, given the small margin, 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.

Recommendation to the Minister

To decide on the volume need for the strategic reserve for next winter (2020-21), 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 Energy within the context of a state aid review 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.

Elia's recommended scenario leads to a margin of 100 MW for Belgium for next winter (2020-21). Therefore, this scenario does not induce a need for constituting a strategic reserve for winter 2020-21.

Looking ahead

Concerning the outlook for **winter 2021-22** and under the current assumptions, the calculations show that the **margin** on the Belgian system for the 'High Impact, Low Probability' scenario will increase to around **200 MW.**

For **winter 2022-23** the **nuclear phase-out** has been taken into account. According to Article 4 of the Nuclear Phase-Out law, Doel 3 is to be decommissioned by 1 October 2022 and Tihange 2 by 1 February 2023. Consequently, for winter 2022-23 and under the current assumptions, Elia has calculated that the **need** on the Belgian system for the 'High Impact, Low Probability' scenario has risen to **500 MW.**

Additionally, and given Belgium's dependence on imports, the future exporting capabilities of our neighbouring countries will continue to have a key impact on the expected adequacy situation and the need for domestic generation in Belgium. Hence, if a further acceleration of conventional power plant decommissioning by 2022-23 takes place, this will result in an even higher strategic reserve need.

For the above-mentioned reasons, and given its goal of providing a sustainable and adequate electricity system with prices that are competitive compared to our neighbouring countries, Elia continues to stress the importance of the ongoing activities related to the introduction of a Capacity Remuneration Mechanism for Belgium in order to ensure the adequacy of the Belgian electricity system once the nuclear phase-out takes effect.

Elia wishes to emphasise that the conclusions of this report are inseparable from the assumptions mentioned in the report. Elia cannot guarantee that these assumptions will actually materialise. 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 2020-21 is 15 januari 2020.

Dit rapport bevat een probabilistische evaluatie van de Belgische bevoorradingszekerheid voor de komende winter (2020-21) 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 EC DG energie, in het kader van het staatssteunonderzoek van het strategisch reserve mechanisme. Dit rapport biedt ook een vooruitblik op de nood van het aanleggen van een strategische reserve voor de winters 2021-22 en 2022-23.

'Base case' scenario

Hypothesen

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

- een groei van 0,4% van de totale jaarlijkse vraag naar elektriciteit in België;
- 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 2019). 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 het gemiddelde gedwongen uitvalratio maar worden apart behandeld in een 'hoge impact, lage waarschijnlijkheid sensitiviteit, die hieronder wordt beschreven;
- geïnstalleerde capaciteit voor fotovoltaïsche en onshore windproductie 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;
- commerciële uitwisselingen tussen België en andere CWE landen worden gemodelleerd door gebruik te maken van historische flow-based domeinen, aangepast om de '*full-grid*' beschikbaarheid in België, de

geplande HTLS upgrades, de ALEGrO interconnector en de effecten van de Duitsland-Oostenrijk (DE-AT) split, in voege sinds 1 oktober 2018, in rekening te brengen
- de beschikbaarheid van de nieuwe interconnectoren met Groot-Brittannië (Nemo Link®) en met Duitsland (ALEGrO), beiden met een capaciteit van 1000 MW;
- een maximum simultane importcapaciteit van 6500 MW voor België voor de winter 2020-21 wordt beschouwd. Deze limiet bestaat uit zowel de import in de CWE regio als de flux op de Nemo Link® interconnector
- een stabiele trend in de resterende geïnstalleerde thermische productiecapaciteit in België met de meest markante wijzigingen de terugkeer van Vilvoorde (GT) naar de markt en de sluiting van de AWIRS biomassa centrale.

België blijft afhankelijk van import voor zijn elektriciteitsvoorziening. Daarom heeft elke verandering in de aangenomen hypothesen voor de naburige landen een mogelijke impact op de situatie in België en op de nood aan een strategisch reserve volume.

De maximum beschikbaarheid van de binnenlandse productie gedurende de winterperiode is cruciaal voor België om zijn bevoorradingszekerheid te garanderen. Daarom zet Elia de eigenaars van productiecentrales er toe aan om maximaal de geplande onderhouden in de winterperiodes te vermijden.

Conclusie

Het 'base case' scenario in deze probabilistische studie voor winter 2020-21 geeft aanleiding tot een marge van 3200 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 contracteren voor winter 2020-21 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 2012 en 2019 zijn niet opgenomen in deze ratio's in het 'base case' scenario gezien hun uitzonderlijk 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 een volumenood strategische reserve te bepalen. Deze aanpak is goedgekeurd door de EC DG energie in het kader van het staatssteunonderzoek van het strategisch reserve mechanisme.

Extra sensitiviteit

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 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. Bijgevolg werd dezelfde analyse, die uitgevoerd was voor België, uitgevoerd voor de Franse nucleaire beschikbaarheid.

Deze analyse van de reële nucleaire beschikbaarheid in Frankrijk over de voorbije zeven winters maakte duidelijk dat een sensitiviteit waarin 3,6 GW nucleaire productiecapaciteit extra in Frankrijk buiten dienst werd gesteld dient aangenomen te worden. Deze capaciteit is verondersteld de hele winter buiten dienst te zijn bovenop de reeds geplande onderhoudswerken en de gesimuleerde gedwongen uitval reeds voorzien in de 'base case' voor Frankrijk.

Conclusie

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 2020-21 om aan de wettelijke bevoorradingszekerheidscriteria te voldoen. De 'grote impact, lage waarschijnlijkheid' sensitiviteit in deze studie leidt tot een marge van 100 MW.

Deze conclusie reflecteert achteruitgang van de situatie voor België vergeleken met de vooruitblik voor winter 2020-21 in het volumerapport van November 2018. Dit is hoofdzakelijk het gevolg van een versnelde uitdienstname van conventionele productie-eenheden in de buurlanden. Deze versnelling werd reeds geïdentificeerd in de Adequacy & Flexibility studie die Elia in juni 2019 publiceerde.

Het resultaat is onafscheidbaar van de genomen hypothesen voor België en de buurlanden. Meer bepaald is het belangrijk aan te stippen dat voor de Belgische nucleaire eenheden:

- de assumpties genomen met betrekking tot de geplande onbeschikbaarheden gebaseerd zijn op de meest recente informatie op de relevante markttransparantie kanalen (REMIT);
- betreffende de specifieke stilstanden van lange duur van enkele nucleaire eenheden in de afgelopen jaren, Elia de sensitiviteitsmethode heeft toegepast. Voor België leidt dit tot een reductie van 1,5 GW aan Belgische nucleaire productiecapaciteit.

Het weerhouden scenario resulteert in een nucleair productiepark voor België waarin:

- 1 GW onbeschikbaar is ten gevolge van het geplande onderhoud op Tihange 2 van 7 november 2020 tot 18 december 2020;
- 0.5 GW onbeschikbaar is ten gevolge van het geplande onderhoud op Doel 2 van 27 februari 2020 tot 9 April 2020;
- 1.5 GW is extra uit dienst beschouwd voor de volledige winter winter 2020-21;
- de onvoorziene uitval ratio's van de resterende nucleaire eenheden, werden in de simulatie bepaald op 3,7%. Dit cijfer is gebaseerd op de historische ongeplande onbeschikbaarheden in de afgelopen 10 jaar, zonder de uitzonderlijke lange stilstanden in rekening te brengen die vermeld werden in vorige paragraaf.

Er is een buffer van 2 maanden tussen het einde van de geplande onderhoudsperiode voor Doel 3 en Tihange 1 voor de start van de winter 2020-21. Echter, een langdurige geplande interventie op Tihange 3 staat gepland van 7 juni 2020 tot 24 oktober 2020, waardoor er geen buffer bestaat tussen het einde van het laatste geplande nucleaire onderhoud en de start van de komende winter 2020-21. Het risico op een vertraagde terugkeer van Tihange 3 sterkt Elia's aanbeveling om een beslissing te maken op basis van het 'grote impact, lage waarschijnlijkheid' scenario.

Wanneer een meer problematische situatie zich voordoet, die verder gaat dan de beschouwde hypothesen, kan dit aanleiding geven tot bevoorradingszekerheidsproblemen in België en aanleiding geven tot een nood aan strategische reserve.

Aanbeveling aan de Minister

Bij het bepalen van een volumenood aan strategische reserve voor komende winter 2020-21 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 EC DG energie, in het kader van het staatssteunonderzoek van het strategisch reserve mechanisme.

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

Elia's aanbevolen scenario leidt tot een marge van 100 MW voor België voor de volgende winter (2020-21). Daarom is er in dit scenario geen nood tot het samenstellen van een strategische reserve voor winter 2020-21.

Een vooruitblik

Betreffende de vooruitblik voor de **winter 2021-22** tonen Elia's berekeningen aan dat onder de huidige hypothesen de **marge** op het Belgische elektrische energiesysteem voor het 'grote impact, lage waarschijnlijkheid' scenario zal stijgen tot **200 MW**.

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. Bijgevolg tonen Elia's berekeningen aan dat voor winter 2022-23, onder de huidige hypothesen de **nood** op het Belgische elektrische energiesysteem voor het 'grote impact, lage waarschijnlijkheid' scenario zal stijgen tot **500 MW.**

Daarenboven, gegeven de Belgische afhankelijkheid van import, zullen ook de toekomstige exportmogelijkheden van onze buurlanden een cruciale impact hebben op de bevoorradingszekerheidssituatie en de noodzaak aan binnenlandse productiecapaciteit in België.

Om bovenvermelde redenen, en gegeven de doelstelling om een duurzaam en betrouwbaar elektriciteitssysteem aan te bieden, met competitieve prijzen met onze buurlanden, blijft Elia het belang benadrukken van de lopende activiteiten met betrekking tot het capaciteitsremuneratiemechanisme voor België, om als dusdanig de bevoorradingszekerheid van het Belgische elektriciteitssysteem op de middellange termijn te garanderen.

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 2020-21 est fixée à la date du 15 janvier 2020.

Ce rapport fournit une évaluation probabiliste de la sécurité d'approvisionnement de la Belgique pour le prochain hiver (2020-21) 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 l'énergie 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 : 2021-22 et 2022-23.

Scenario 'base case'

Hypothèses

Le scénario 'base case' comprend les hypothèses listées ci-dessous (seuls les facteurs déterminants pour la Belgique sont énumérés ci-dessous):

- une croissance de 0,4% par an pour la consommation totale d'électricité en Belgique;
- 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') ;
- 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;
- les échanges commerciaux entre la Belgique et les autres pays de la zone CWE sont modélisés à l'aide des domaines flow-based historiques, modifiés afin de prendre en compte une disponibilité complète du réseau en Belgique, l'installation des HTLS, la mise en service de l'interconnexion avec l'Allemagne (ALEGrO) et en

incorporant les effets de la séparation des bidding zones Allemagne-Autriche (DE-AT), cette dernière est en vigueur depuis le 1er octobre 2018;
- la disponibilité des interconnexion avec la Grande-Bretagne (Nemo Link®) et avec l'Allemagne (ALEGrO), chacune avec une capacité de 1000 MW;
- une capacité d'importation maximale simultanée de 6500 MW pour la Belgique pendant l'hiver 2020-21 est considérée. Cette limite est appliquée à la somme des importations depuis la zone CWE et sur le flux sur Nemo Link®;
- une tendance stable au niveau de la capacité de production thermique installée en Belgique avec comme changements les plus notables, le retour de la centrale de Vilvoorde sur le marché en tant qu'OCGT ainsi que la fermeture de la centrale à biomasse d'AWIRS.

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 (2020-21) indique une marge de 3200 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 2020-21 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 afin d'évaluer 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 l'énergie de la Commission Européenne dans le contexte de l'examen des aides d'Etat pour le mécanisme de réserves stratégiques.

Sensitivité additionnelle

Compte tenu de leur impact significatif sur l'adéquation, il est toutefois important d'analyser un scénario 'High Impact, Low Probability'. De précédentes études 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 étaient temporairement hors service à la demande de l'Autorité de Sûreté Nucléaire française. Par conséquent, une analyse similaire à celle effectuée pour la Belgique a été menée pour la disponibilité de la capacité nucléaire française.
De la même façon que pour la génération nucléaire belge, les études comparant la disponibilité du parc nucléaire français modélisé 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 3,6 GW de capacité de production nucléaire serait comme hors-service en France. 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 pour la France.

Conclusion

La prise en compte de cette analyse de sensitivité afin de prendre en compte les événements ayant un grand impact, à faible probabilité, l'analyse n'identifie pas la nécessité de contracter une réserve stratégique pour l'hiver 2020-21 afin de respecter les critères légaux. Le scénario 'High Impact, Low Probability' de cette étude conduit à une marge de 100 MW.

Cette conclusion reflète une dégradation de la situation en Belgique comparativement à la prévision précédente pour l'hiver 2020-21, cette dernière datant du rapport sur les réserves stratégiques de novembre 2018. Ceci s'explique principalement par l'accélération du démantèlement des unités de générations conventionnelles dans les pays voisins. Ce phénomène a déjà été souligné dans le contexte de l'étude 'Adequacy & Flexibility' publiée en juin 2019.
Cependant, ce résultat est indissociable des hypothèses considérées, tant pour la Belgique que pour les pays voisins. En ce qui concerne plus particulièrement les unités de production nucléaire belges, il est important de noter que:

- 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);
- en ce qui concerne les pannes de longue durée spécifiques de certaines centrales nucléaires au cours des dernières années, Elia a adopté une approche de sensitivité. Pour la Belgique, cela entraîne une réduction supplémentaire de 1,5 GW de la capacité de production nucléaire belge.

Le scénario retenu donne lieu à un parc de production nucléaire en Belgique pour lequel:

- 1 GW est indisponible suite à la maintenance planifiée de Tihange 2 prévue du 7 novembre 2020 au 18 décembre 2020;
- 0.5 GW est indisponible suite à la maintenance planifiée de Doel 2 prévue du 27 février 2020 au 9 avril 2020 ;
- 1,5 GW est en outre mis hors service pour l'ensemble de l'hiver 2020-21;
- De plus, les arrêts fortuits des unités nucléaires restantes sont simulés statistiquement à un taux de 3,7%, basé sur les indisponibilités historiques non planifiées des 10 dernières années, à l'exclusion des pannes de longue durée qui sont décrites dans le point précédent.

En considérant les périodes de maintenance prévues à ce jour, une marge de sécurité de deux mois est observée entre la fin de la dernière période de maintenance pour Doel 3 et Tihange 1 et le début de l'hiver 2020-21. Par ailleurs, une révision complète de Tihange 3 est planifiée entre le 7 juin 2020 et le 24 octobre 2020, ce qui ne laisse aucune marge de sécurité entre la fin de la dernière période de maintenance (comme planifiée à ce jour par le propriétaire de l'unité de production) et le début de l'hiver prochain, 2020-21. Le risque de retards pour les maintenances mentionnées ci-dessus renforce Elia dans sa recommandation de prendre une décision basée sur le scénario 'High Impact, Low Probability'.
Inutile de mentionner que des situations allant au-delà des hypothèses considérées pourraient à nouveau poser un problème d'adéquation pour la Belgique et un besoin correspondant de réserve stratégique.

Recommandation au Ministre

Afin de prendre une décision sur le volume à constituer pour la réserve stratégique pour l'hiver prochain (2020-21), 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 l'énergie 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 100 MW pour la Belgique pour l'hiver prochain (2020-21). Par conséquent, ce scénario n'induit pas la nécessité de constituer une réserve stratégique pour l'hiver 2020-21.

Un regard vers l'avenir

En ce qui concerne les perspectives pour **l'hiver 2021-22** et selon les hypothèses actuelles, Elia estime que la **marge** du système belge pour le scénario 'High Impact, Low Probability' augmentera à hauteur d'environ **200 MW**.
En ce qui concerne **l'hiver 2022-23**, le début du démantèlement des unités nucléaires a été pris en compte. D'après la loi sur la sortie des centrales nucléaires, article 4, Doel 3 devrait être arrêtée le 1er octobre 2022 et Tihange 2, le 1er févier 2023. Dès lors, pour l'hiver 2022-23 et selon les hypothèses actuelles, Elia estime qu'il y aura un **besoin** à hauteur de **500 MW** pour le scénario 'High Impact, Low Probability'.

En outre, et compte tenu de la dépendance de la Belgique à l'égard des importations, les futures capacités d'exportation de nos pays voisins auront également un impact déterminant sur la situation d'adéquation prévue et sur la nécessité de capacité de production en Belgique. Dans le cas où une accélération (en plus de ce qui a été prévu dans les scénarios) de l'arrêt de centrales conventionnelles serait observée à l'horizon 2022-23, un besoin en réserve stratégique d'autant plus grand serait nécessaire pour satisfaire le critère d'adéquation.
Pour les raisons susmentionnées et compte tenu de son objectif de fournir un système électrique durable et adéquat à des prix compétitifs par rapport aux pays voisins, Elia continue de souligner l'importance des activités en cours liées à la mise en place d'un mécanisme de rémunération de la capacité pour la Belgique, et ce, afin de garantir l'adéquation du système électrique belge à moyen terme.

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[1] 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 2020-21 winter period that Elia is required to conduct by 15 November 2019. Elia previously carried out assessments for the winters 2014-15 up to and including 2019-20. 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 0 sets out the results of the assessment for winter 2020-21, 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.

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[1] 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.

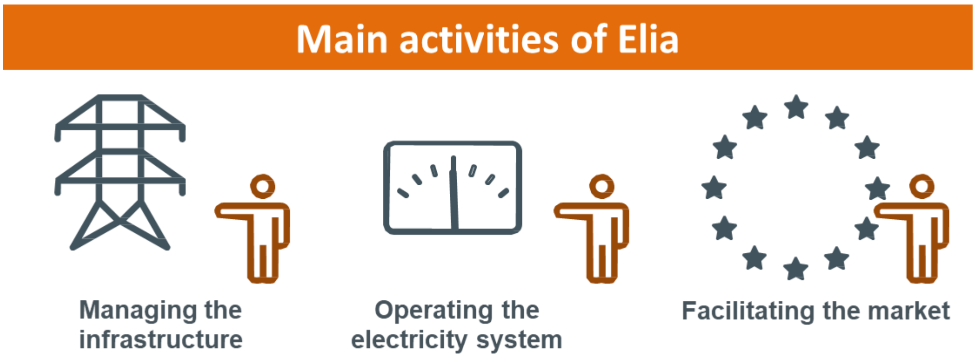


Figure 1.2

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[2]) 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.

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

— The **federal regulator CREG**[3] 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[4]

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):

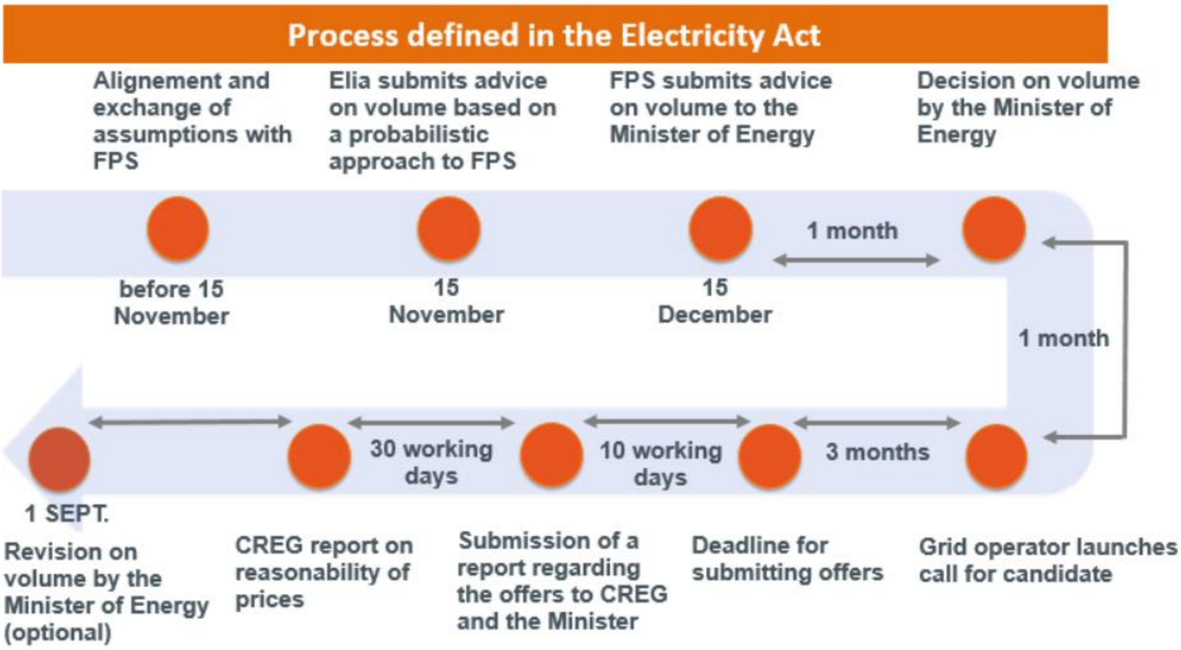


Figure 1.4

Art.7bis – 7sexies

— ***Prior to 15 November****: DG Energy*[5] *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*

[3] CREG = Commission for Electricity and Gas Regulation
[4] 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.
[5] 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 §3 - §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.

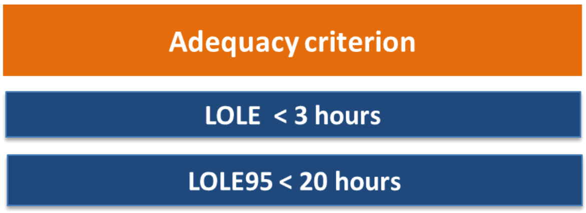


Figure 1.5

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[6] 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.*[7]

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[8]. 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.

[6] Load = demand for electricity

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

[8] 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.

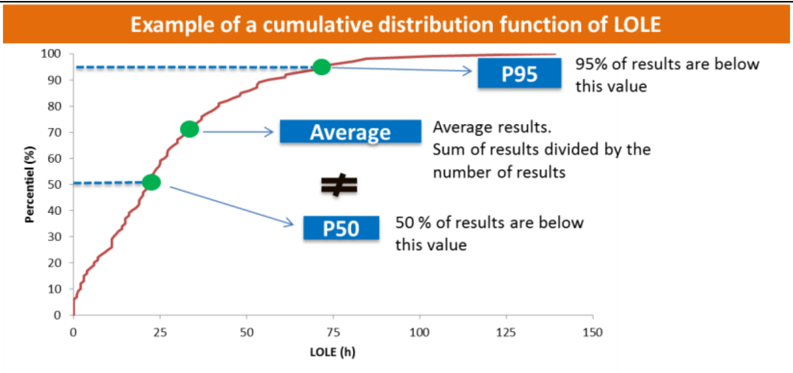


Figure 1.6

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.

The lack of harmonised European or regional standards defining security of supply

In 2014, the Council of European Energy Regulators (CEER) published a report providing an overview of the adequacy assessments in various European countries [2]. That report highlighted the lack of harmonisation in the methodology and adequacy criteria used in these countries and its conclusions still apply to the present analysis. In seven countries, Great Britain, France, the Netherlands, Finland, Hungary, Belgium and the Republic of Ireland, indicators are based on a probabilistic adequacy assessment. However, the criteria used differ (an LOLE of three hours per year in Belgium, France and Great Britain, of four hours per year in the Netherlands, and of eight hours per year in the Republic of Ireland). By contrast, Sweden and Spain apply a quantitative methodology based on the power balance (i.e. capacity margin).

The future framework for determining the security of supply standard

As part of the Clean Energy Package for all Europeans (CEP), Regulation (EU) 2019/943 of 5 June 2019 on the internal market for electricity provides an additional and future framework for determining reliability standards. Articles 23 and 25 stipulate that a methodology for calculating the reliability standard will be adopted (proposal by ENTSO-E to be adopted by ACER) and used for determining national reliability standards.
The methodologies and resulting reliability standards are not yet known and therefore the current legal standards, as formulated in the Belgian Electricity Act apply and are used for this analysis.

Regulation (EU) 2019/943 specifies the following:

Article 23(6) - European resource adequacy assessment):
6.By 5 January 2020, the ENTSO for Electricity shall submit to ACER a draft methodology for calculating:
(a) the value of lost load;
(b) the cost of new entry for generation, or demand response; and
(c) the reliability standard referred to in Article 25.
The methodology shall be based on transparent, objective and verifiable criteria.

Article 25 Reliability standard
1. When applying capacity mechanisms Member States shall have a reliability standard in place. A reliability standard shall indicate the necessary level of security of supply of the Member State in a transparent manner. In the case of cross-border bidding zones, such reliability standards shall be established jointly by the relevant authorities.
2. The reliability standard shall be set by the Member State or by a competent authority designated by the Member State, following a proposal by the regulatory authority. The reliability standard shall be based on the methodology set out in Article 23(6).
3. The reliability standard shall be calculated using at least the value of lost load and the cost of new entry over a given timeframe and shall be expressed as 'expected energy not served' and 'loss of load expectation'.
4. When applying capacity mechanisms, the parameters determining the amount of capacity procured in the capacity mechanism shall be approved by the Member State or by a competent authority designated by the Member State, on the basis of a proposal of the regulatory authority.

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[9]) and generation capacity (SGR[10]):

- 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

[9] SDR = strategic demand reserve
[10] 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 [7].

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).

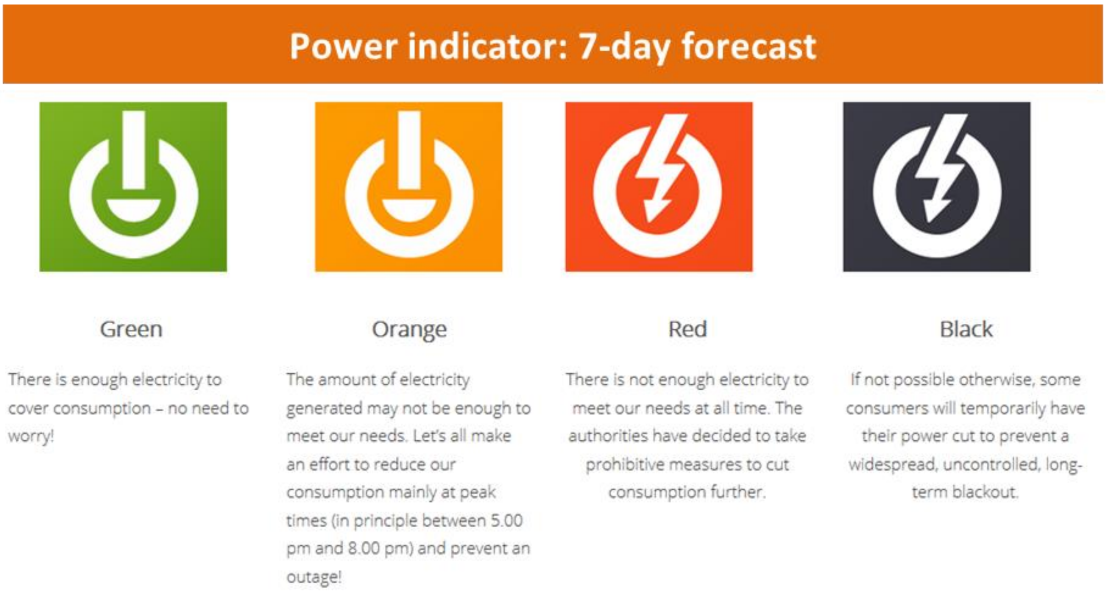


Figure 1.8

At the same time, when a structural shortage[11] 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 [7].
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[12] 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[13] 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[14], 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.).

[11] 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.
[12] RSS = really simple syndication
[13] CWE: Central West Europe
[14] An aggregator is a demand service provider that combines multiple short-duration consumer loads for sale or auction in organised energy markets.

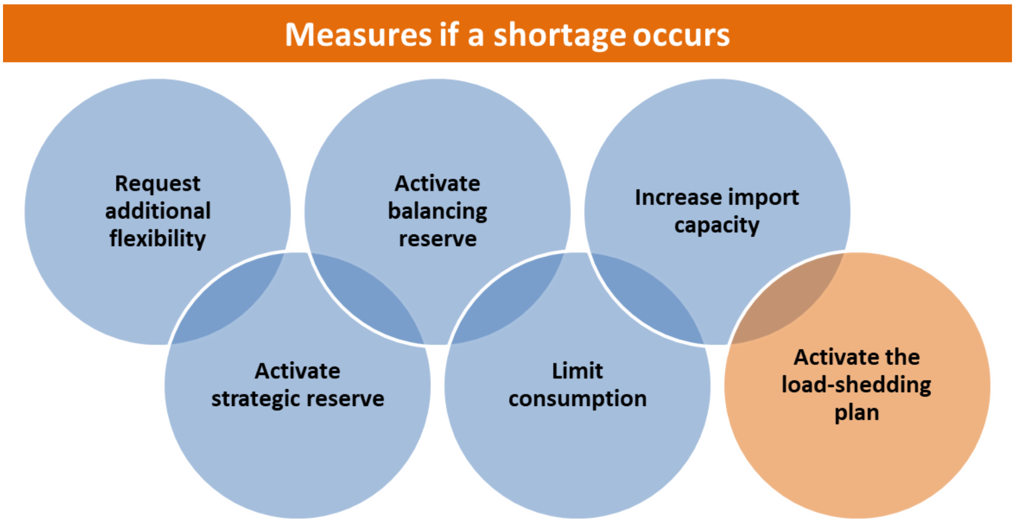


Figure 1.9

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.

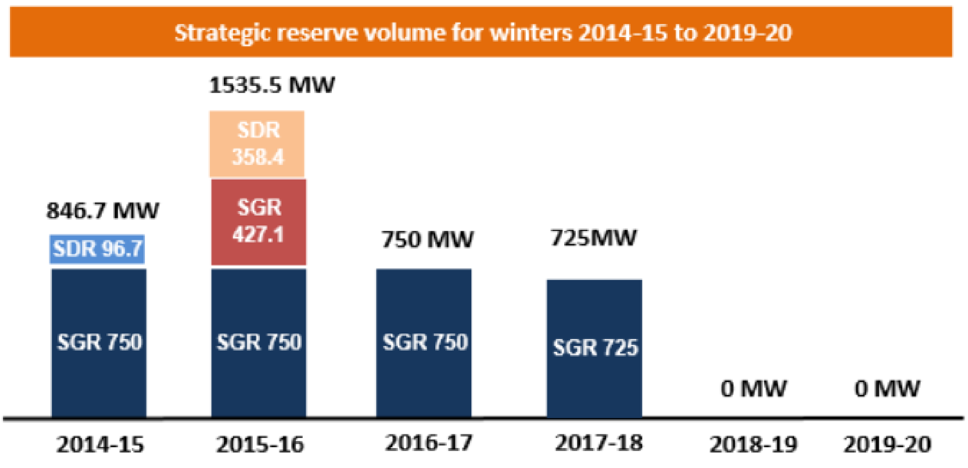


Figure 1.10

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 2019: 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.

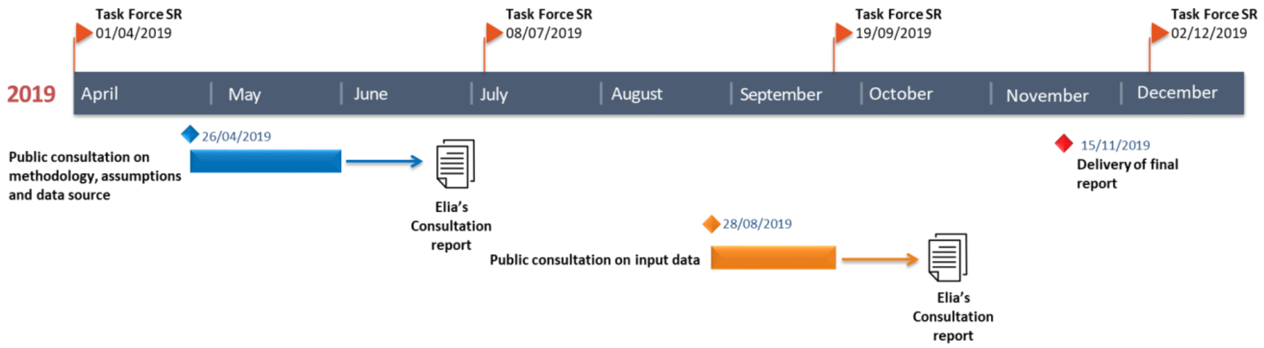


Figure 1.11

The consultations were announced at meetings of the Strategic Reserve Implementation Task Force, more specifically on 1 April 2019 for the first consultation and on 8 July 2019 for the second consultation.

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.

As this is the seventh iteration of the strategic volume need determination, the methodology has been refined and is stable. Therefore, this year's methodology consultation document was restructured, moving more general descriptions to the appendices whilst focussing on changes and improvements in the main text in order to make the document more user-friendly.

1.6.1. Feedback from stakeholders

For each consultation, Elia received four responses from stakeholders during the consultation period. These responses 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' [7] meeting on 8 July 2019 for the first consultation, and on 2 December 2019 an overview of the received responses will be provided for the second consultation.

PUBLIC CONSULTATION 1

Content: methodology, assumptions, data sources

Consultation Period: 26 April to 24 May 2019 at 18:00

Responses received: 4

Amount of questions: 33

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

Consulted document and Consultation Report: [8]

PUBLIC CONSULTATION 2

Content: Input data

Consultation Period: 28 August to 25 September 2019 at 18:00

Responses received: 4

Amount of questions: 17

Subjects: Data, Assumptions, List of Power Plants, Demand Growth, Market Response, Flow-based

Consulted Document and Consultation Report: [9]

Figure 1.12

1.7. Improvements in methodology and modelling compared to the previous assessment

Following the public consultation on methodology, hypotheses and data sources, several improvements in the modelling were implemented for this assessment. Below, an overview is provided of the new methodological improvements that were incorporated in the assessment for winter 2020-21, compared to the assessment performed for winter 2019-20.

Flow-based modelling

Before the go-live of the German-Austria bidding zone split (DE-AT split) the CWE flow-based domains were described using the net positions of Belgium, France, the Netherlands and Germany (+ Austria). Since the DE-AT split, Austria has been treated as a separate bidding zone. The net position of Austria is an additional variable for which the domains need to be described. This year's analysis marks the first time that historical flow-based data incorporating the DE-AT split is available.

The integration of ALEGrO in the CWE flow-based market area has a similar effect. As ALEGrO will be an HVDC interconnector, the flow is controllable. This means that the flow-based domains need to be described in terms of flow setpoints on ALEGrO.

The addition of extra variables (Austrian net position, Alegro setpoint) introduces new challenges in the numerical modelling of flow-based market exchanges.

In the first step of flow-based modelling, historical domains need to be clustered. In this step domains are chosen that represent the clusters. Domains are clustered based on their geometrical shape. While one has an intuitive feeling of the similarity of shapes up to three dimensions (e.g. a ball resembles an egg), this is much harder in higher dimensions. Given that the new flow-based domains are six-dimensional, a new definition for 'geometrical shape likeness' was tried and tested, resulting in the successful clustering of historical days 1/10/2018 to 15/3/2019 into four winter days.

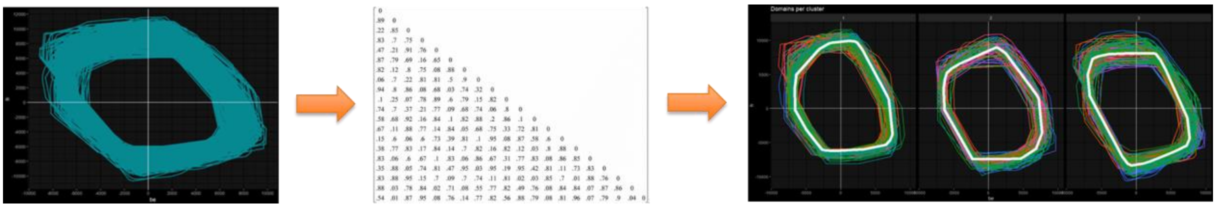


Figure 1.13 The flow-based typical day clustering process

A systematic approach for correlating the flow-based domains with climatic data is taken into account, following the same approach used last year. This approach enables, for example, specific combinations of climatic factors, like wind, and demand to be linked with the representative flow-based domains to be considered in the simulations.

Elia then corrected these domains for historical grid outages and updated the grid conditions, notably introducing the effect of NEMO, ALEGrO & HTLS upgrades of existing lines (High Temperature Low Sag lines use a different alloy for the conductor which allows for a higher temperature and thus higher transmission capacity).

A new way of representing six-dimensional flow-based domains in the Antares solver had to be developed in order to deal with the increased computational complexity due to the more complex shape of the new domains.

Finally, a 20% minimum remaining available margin (minRAM20%) for day-ahead flow-based market coupling (FBMC) domains used in the assessment was taken into account. The effect of minRAM20% is taken into account as a baseline assumption in this volume assessment for strategic reserves, since this feature is currently operational in the capacity calculation of the FBMC framework. Notwithstanding the daily verification of the minRAM20% feasibility by the TSOs, it is assumed – in particular if any country suffers severe adequacy issues – that every effort will be made to ensure the application of the minRAM20% principle.

Improved demand modelling for all European countries

At ENTSO-E, a new tool for creating load profiles for the various climatic years for all European countries has been developed. In order to keep consistency with the European adequacy assessments, Elia has incorporated it into this analysis.

Improved hydro modelling

Via an ENTSO-e data collection, a more detailed database of hydro generation is available to all TSOs. This database distinguishes four hydro generation categories:

- Pumped storage closed loop;
- Pumped storage open loop (with inflows);
- Reservoir storage with inflows;
- Run-of-river (or very small reservoirs).

In the context of MAF [16] a more detailed implementation of these four categories was devised in order to respect a plethora of constraints involving hydro generation (pump cycle efficiencies, reservoir capacities, seasonal inflow patterns, run-of-river generation patterns, spatial correlation, etc.). This improved approach to hydro modelling was implemented in this year's strategic reserve volume assessment model.

Market response

The methodology for evaluating the available market response was developed in close cooperation with the stakeholders in the context of determining the strategic volume for winter 2017-2018. This year the quantitative part of the process, i.e. the analysis of aggregated power-exchange data, was again carried out in order to update the figures on the available market response (see section 3.3).

1.8. 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 1.14 affords a general overview. Each study is then presented in further detail below.

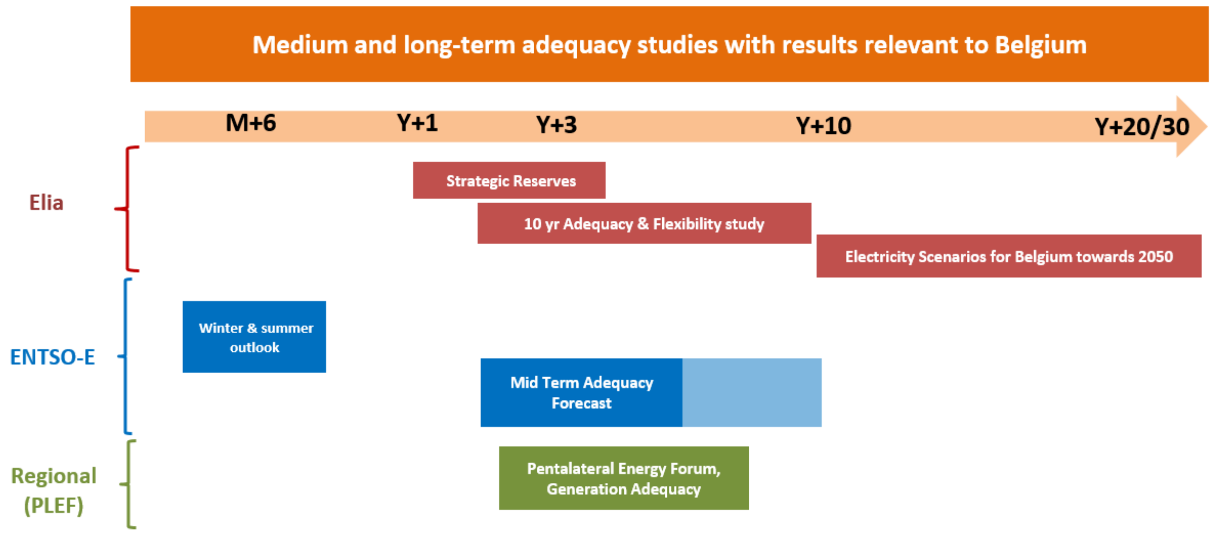


Figure 1.14

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.

1.8.1. 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 (FBP) 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 [10]. 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.

1.8.2. Electricity Scenarios for Belgium towards 2050

Electricity Scenarios for Belgium towards 2050

METHOD:	Probabilistic
TIME-FRAME:	2030-2040-2050
Latest publication:	11/2017
Scope	22 countries
Country results:	Belgium
Frequency of publication:	ad hoc Elia publication

This study (Elia initiative) [11] analysed both short-term and long-term policy options regarding the future energy mix for Belgium between now and 2050, bearing in mind the planned nuclear phase-out in 2025, and striving to establish a sustainable, adequate electricity system.
In addition to quantifying the various future scenarios for 2030 and 2040, the study also focused on a few options for sustainability and ensuring short-term security of supply. These options are needed to cope with the planned 2025 nuclear phase-out and provide sufficient replacement capacity to guarantee security of supply.

1.8.3. 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[15] publishes a report entitled *Winter Outlook and Summer Review'[12].* 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.

1.8.4. ENTSO-E: Mid-Term Adequacy Forecast

ENTSO-E Mid Term Adequacy Forecast

METHOD:	Probabilistic
TIME-FRAME:	2021 - 2025
Latest publication:	11/2019
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 edition of this report, MAF 2019, is expected to be published and submitted for public consultation on 18 November [16], giving stakeholders in the European energy market an overview of the national and European adequacy situation. The assessment uses best-estimate scenarios based on

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

bottom-up data collection from TSOs, and focuses on the LOLE and ENS as adequacy indicators. The 2019 report includes an assessment for 2021 and 2025 covering all European countries. The MAF study as pan-European adequacy assessment, uses several probabilistic models but follow the same methodology.

Elia is an active contributor, as one of the MAF modelling parties and by helping to improve the methodology and modelling for subsequent editions, since the planned improvements are entirely consistent with Elia's adequacy assessment approach. The MAF report is also expected to evolve into the so-called European Resource Adequacy Assessment (ERAA) within the requirements laid down by the CEP Regulation.

1.8.5. Pentalateral Energy Forum (PLEF): Regional Generation Adequacy Assessment

Penta Lateral Energy Forum Adequacy study

METHOD:	Probabilistic
TIME-FRAME:	2021-2025
Estimated publication:	Q1 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. Elia is actively contributing as one of the modelling parties within PLEF [13].

The third PLEF study will be carried out by late 2019 and early 2020 and is expected to be published in early 2020. The study will cover years 2021 and 2025 and will focus on regional sensitivities, complementary to the MAF2019 Base Case scenarios.

1.9. Disclaimer

This report provides a probabilistic assessment of Belgium's security of supply and the need for strategic reserves for the winter 2020-21, with an outlook for winters 2021-22 and 2022-23. 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.

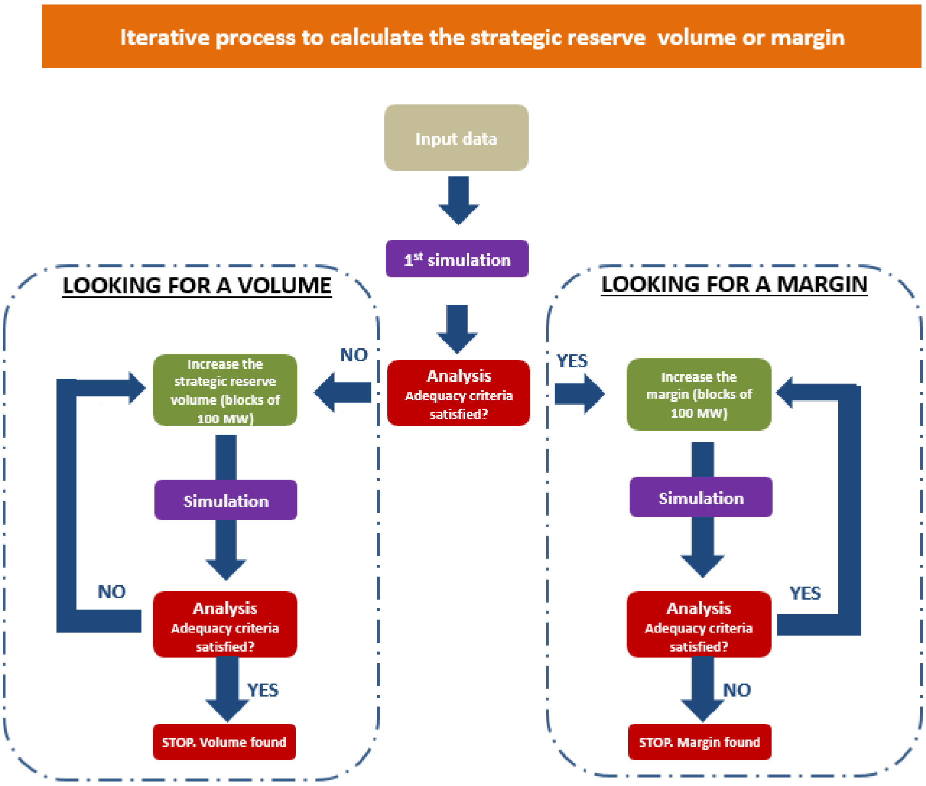


Figure 2.1

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 20 neighbouring 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)

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, 20 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 2.23 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.

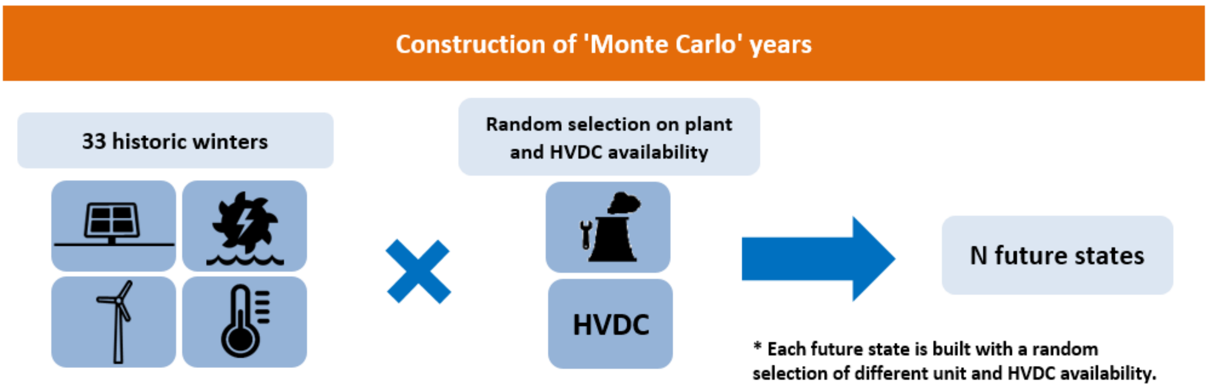


Figure 2.3

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[14], 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.

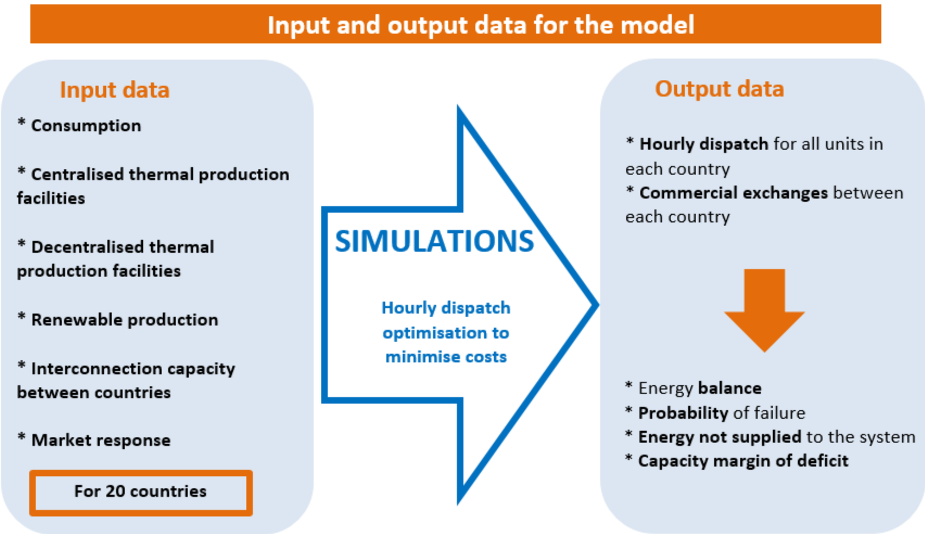


Figure 2.4

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.

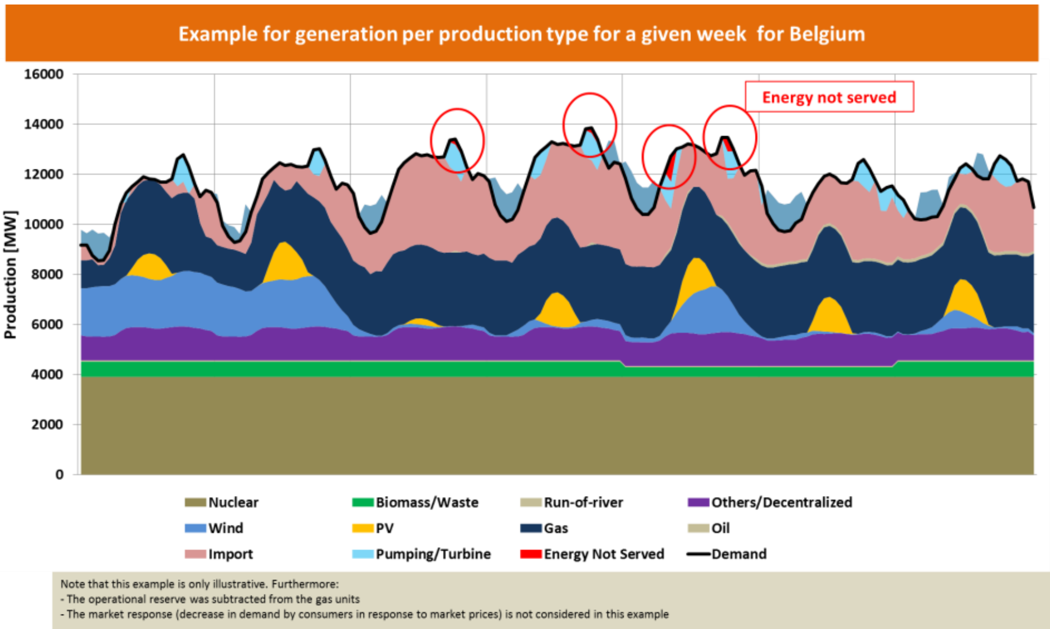


Figure 2.5

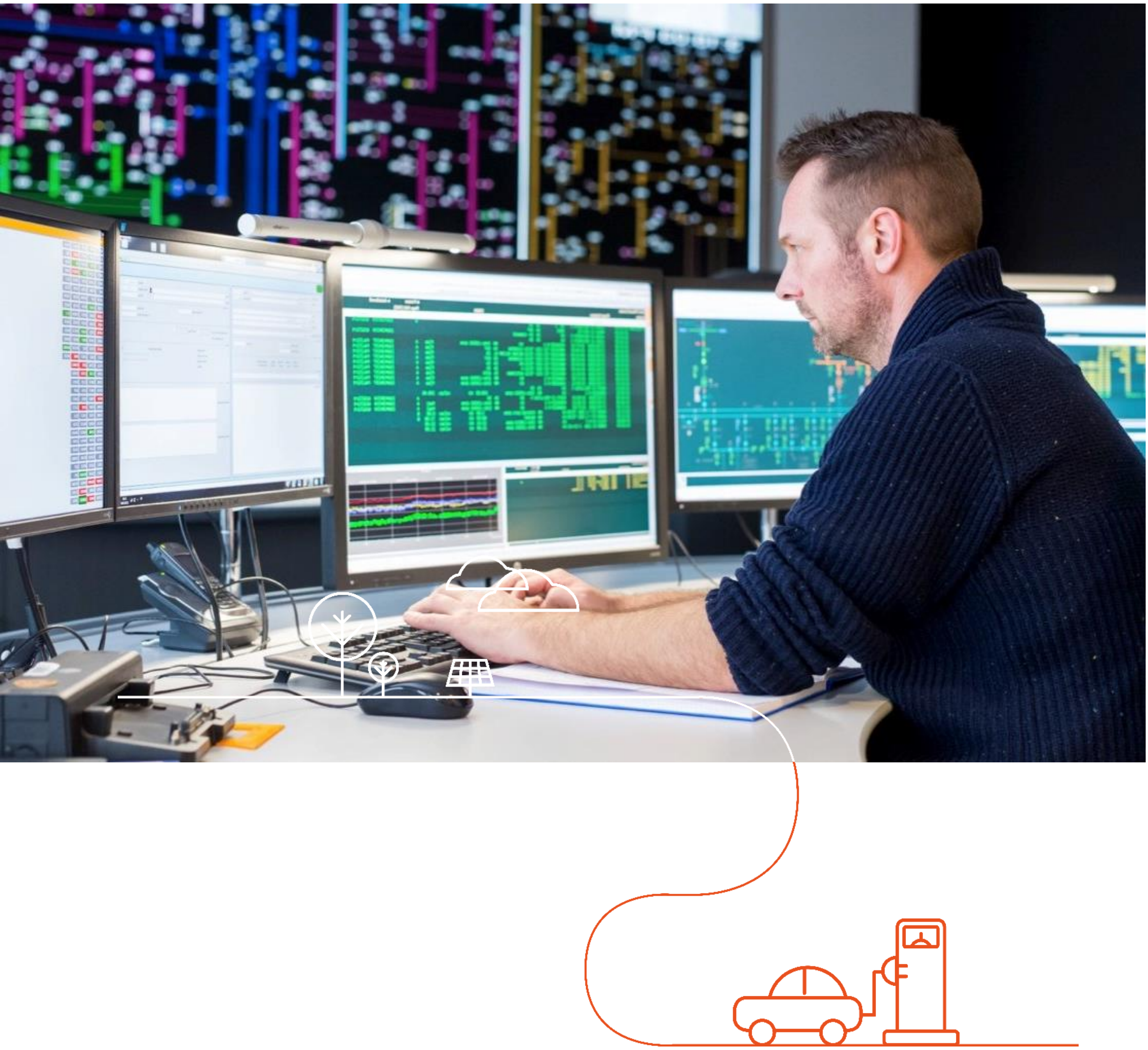
2.4 Iterative process for calculating the additional capacity need

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 statistica [illegible] 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 details the Belgian market response. Finally, section 3.4 summarises 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 2020 for winter 2020-21. 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 or natural gas or related to the capacity and use of LNG facilities, 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 organised 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 [23] 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 [24] 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 was 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. The modelling details are provided in section 8.1 (Appendix).

3.1.1 Wind and solar forecasts

The FPS Economy consults Belgium's three regional authorities to obtain forecasts for the installed capacity of onshore wind and photovoltaic production. Further details of these forecasts are provided in sections 3.1.1.1 and 0. Elia takes as its basis the latest information available to consolidate a forecast of the installed capacity of offshore wind. This is further elaborated in section 3.1.1.2.

3.1.1.1 Wind onshore

Figure 3.1 shows the actual increase over time in the installed capacity from onshore wind generation and the forecast consolidated by the FPS Economy. The average forecast development amounts to a yearly increase of approximately 140 MW.

+140 MW/year on average

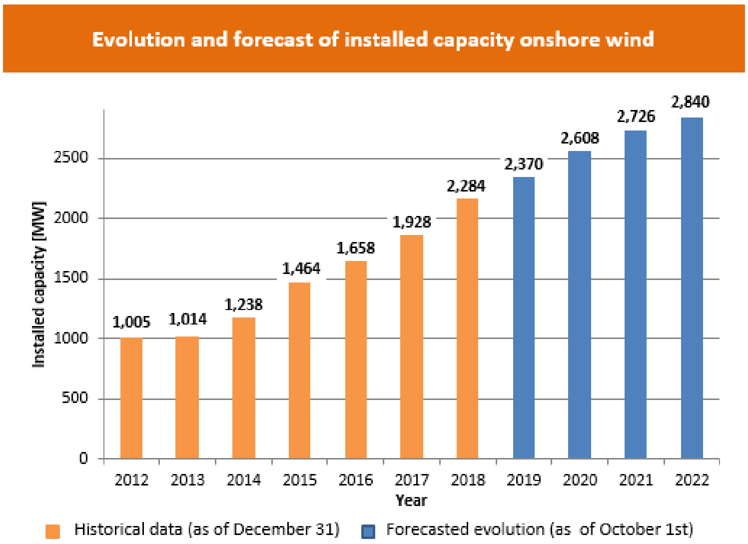


Figure 3.1

3.1.1.2 Wind offshore

The Belgian government awarded domain concessions for the construction and operation of offshore wind generation facilities to nine wind farms (see Figure 3.2). Once the Norther and Northwester 2, Seastar and Mermaid wind farms come on-stream, the total installed capacity from offshore wind generation will increase to 2253 MW in the first analysed winter (2020-21). Figure 3.3 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 for 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 3 winters.

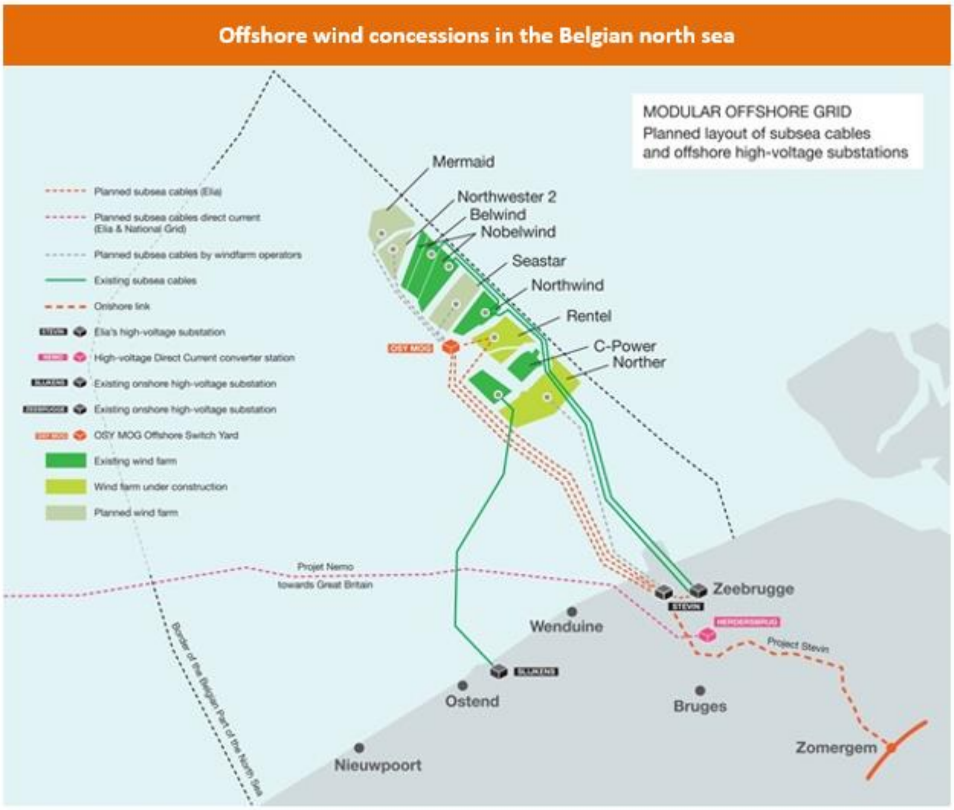


Figure 3.2

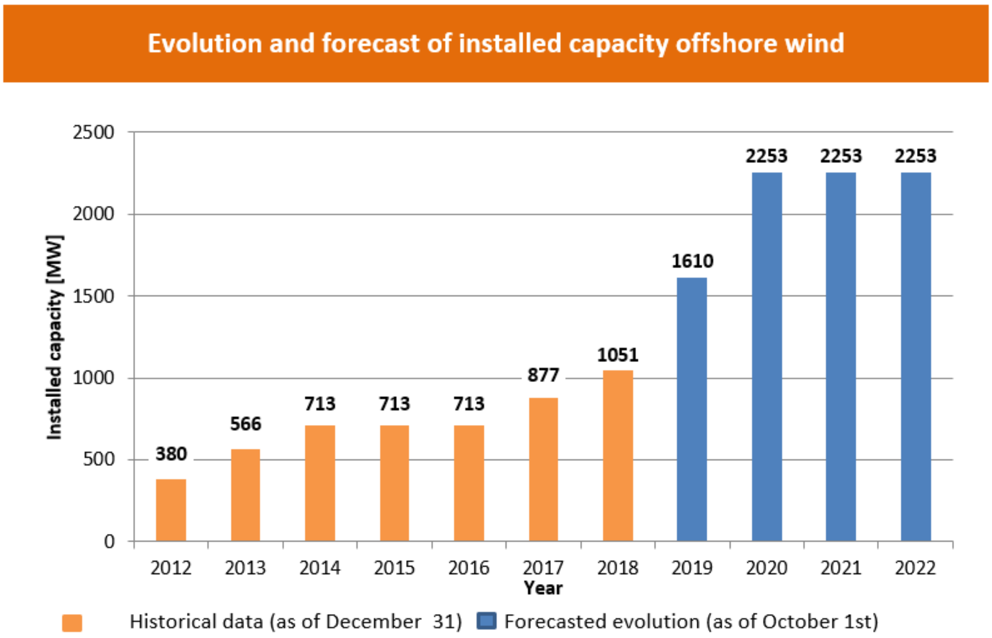


Figure 3.3

3.1.1.3 Solar

Figure 3.4 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 is approximately 425 MW.

+ 425 MW/year on average

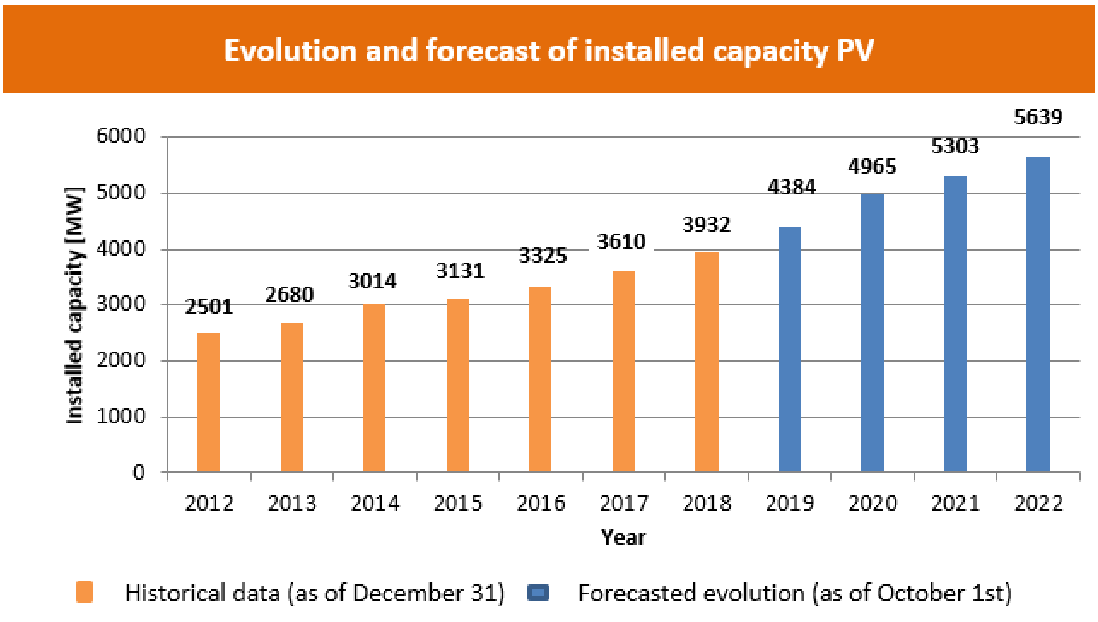


Figure 3.4

3.1.2 Biomass, waste and CHP facilities

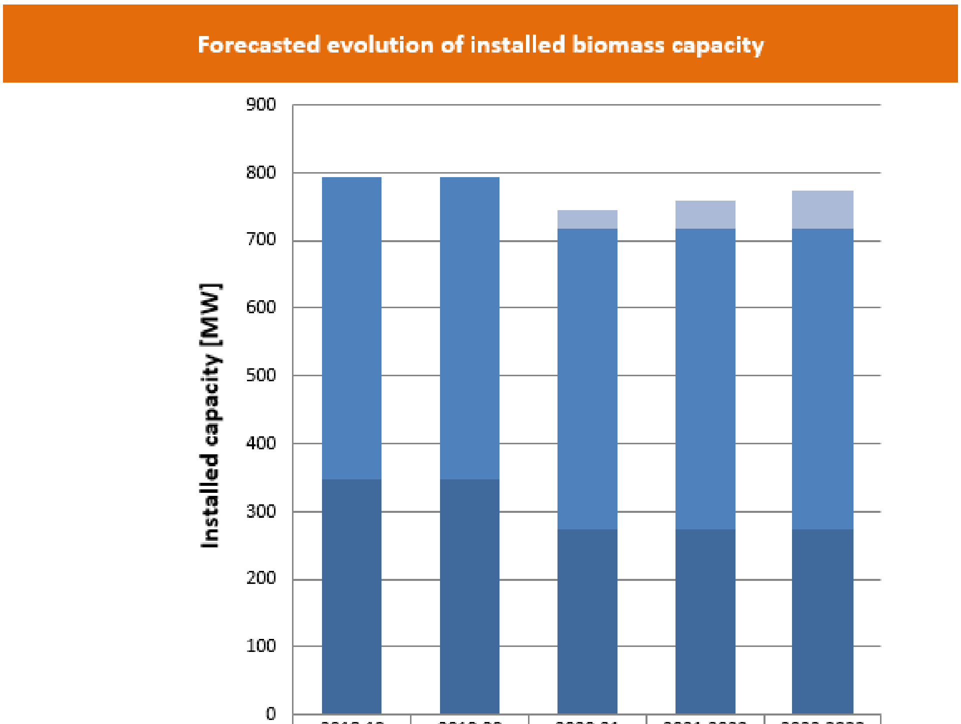
This section elaborates on the installed capacity of biomass, waste and combined heat and power (CHP) production facilities in Belgium. Elia maintains a database of centralised and decentralised generation units, which is updated on a monthly basis following exchanges with DSOs and direct clients of Elia. The database includes units covered by a CIPU[16] 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.**

Following a discussion with FPS Economy, it was decided to determine installed **biomass** generation capacity based on the information in the Elia generation unit database. Subsequently, a capacity growth rate determined by FPS

[16] 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.

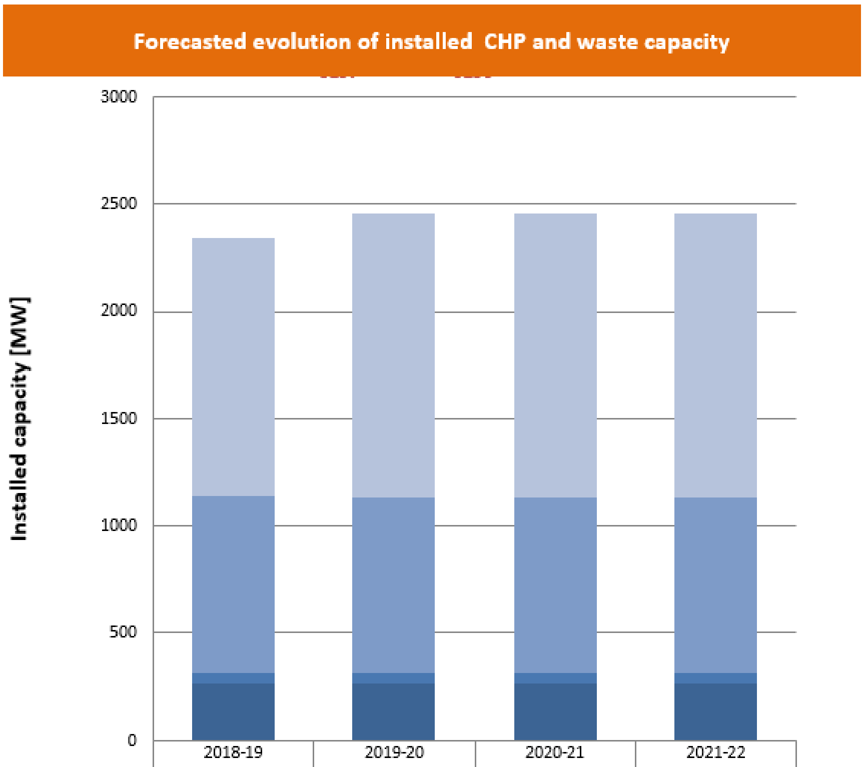
Economy after consultation with the Regions was added in order to predict installed generation capacity for the next three winters. This forecast is generally in line with the information in the Elia database. Figure 3.5 shows the forecast increase in installed capacity from biomass generation in Belgium. Awirs 4 is expected to be decommissioned by 1 September 2020, resulting in a 75 MW decrease as of the first winter considered in this strategic reserve volume assessment. The figure differentiates between units covered by a CIPU contract and units not covered by such contracts. Furthermore, 'additional biomass units' are included in keeping with the forecast provided by FPS Economy. These additional biomass units are not deemed to be subject to a CIPU contract.



	2018-19	2019-20	2020-21	2021-2022	2022-2023
Additional biomass (non-CIPU)	0	-	27	40	57
Biomass non-CIPU	445	445	445	445	445
Biomass CIPU	348	348	273	273	273

Figure 3.5

Similarly, it was decided to determine installed **CHP and waste generation** 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 3.6 shows the forecast increase in installed capacity from CHP and waste generation. Again, the figure differentiates between units covered by a CIPU contract and those not covered by such contracts. Based on Elia's generation database, no notable change is predicted regarding the installed capacity of waste-powered units, and an increase of approximately 120 MW is anticipated for CHP units not covered by a CIPU contract.



	2018-19	2019-20	2020-21	2021-22
CHP non-CIPU	1206	1324	1324	1324
CHP CIPU	821	821	821	821
Waste non-CIPU	51	46	46	46
Waste CIPU	267	267	267	267

Figure 3.6

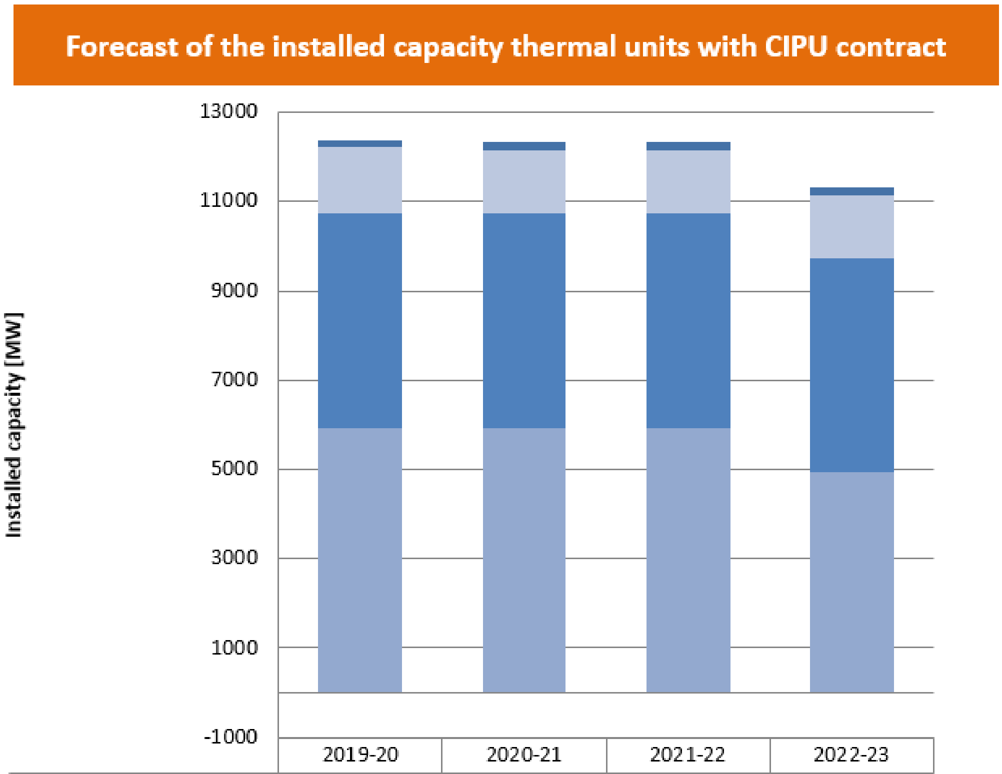
3.1.3 Thermal generation under a CIPU contract

This section details Belgian thermal generation units covered by a CIPU contract. Biomass, waste, and CHP generation units covered by such contracts were discussed in section 3.1.2 above. Section 3.1.3 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. This is described in greater detail in section 3.1.3.2.

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 realising the hypothetical volumes, as this is the producers' responsibility. Figure 3.7 shows the forecast output from thermal generation units covered by a CIPU contract at the start of each winter.

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



	2019-20	2020-21	2021-22	2022-23
Turbojet	158	176	176	176
Biomass, CHP, and Waste	1487	1412	1412	1412
Gas CCGT/GT/CL	4807	4807	4807	4807
Nuclear	5919	5943	5943	4937

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 two time horizons considered: winter 2020-21 and winter 2021-22. For the last 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.

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. This is explained in detail in section 3.1.3.2.

Compared to the last strategic reserve study, the installed capacity of CCGT and OCGT is higher than in the previous years. Vilvoorde OCGT, HAM GT and Izegem have revoked their closure and will therefore still be in the market.

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 [53].

3.1.3.2 Availability of thermal generation covered by a CIPU contract

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 maximally avoid all planned maintenance of their units during the winter period (for details, see *Method and hypotheses used for the calculation of the maximal maintenance curve* below).

Nevertheless, 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 2020-21 analysis. Note that no non-nuclear revisions are scheduled during wintertime.

— TIHANGE 2 undergoing maintenance from 07/11/2020 until 18/12/2020 (inclusive);
— DOEL 2 undergoing maintenance from 27/02/2021 until 09/04/2021 (inclusive).

Furthermore, in 2020 and 2021, yet outside of the analysed windows of November until March, the following additional nuclear outages are scheduled:

— TIHANGE 3 undergoing maintenance from 07/06/2020 until 24/10/2020 (inclusive);
— DOEL 1 undergoing maintenance from 24/04/2021 until 04/06/2021 (inclusive).

Planned outages 2020-2021					
Unit	Fuel	Pmax Available (MW)	Pmax Available after outage(MW)	Start outage	End outage
DOEL 1	NU	445	0	24/04/2021	04/06/2021
DOEL 2	NU	433	0	27/02/2021	09/04/2021
DOEL 3	NU	1006	0	28/08/2021	05/10/2021
DOEL 4	NU	1039	0	23/10/2021	30/11/2021
TIHANGE 2	NU	1008	0	07/11/2020	18/12/2020
TIHANGE 3	NU	1038	0	07/06/2020	24/10/2020
based on REMIT consulted on 15/10/2019					

The announced revision on REMIT that will be taken into account for winter 2021-22 are the following:

- TIHANGE 1N undergoing maintenance from 05/02/2022 until 08/03/2022 (inclusive);
- TIHANGE 1S undergoing maintenance from 05/02/2022 until 08/03/2022 (inclusive);
- TIHANGE 3 undergoing maintenance from 21/02/2022 until 31/03/2022 (inclusive);
- DOEL 2 undergoing maintenance from 19/02/2022 until 01/04/2022 (inclusive) and from 07/05/2022 until 13/05/2022;
- DOEL 4 undergoing maintenance from 23/10/202 until 30/11/2021 (inclusive).

In 2022, outside of the winter period, the following nuclear revision is scheduled:

- DOEL 1 undergoing maintenance from 30/04/2022 until 10/06/2022 (inclusive).

Today, no nuclear maintenance has been announced for winter 2022-23.

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 2007-2018 and using the availability for generation units nominated in the day-ahead market. The available public data from ENTSO-E Transparency [24] were used for historical years when available (i.e. only for 2015-2018 period). The results are shown in Figure 3.8.

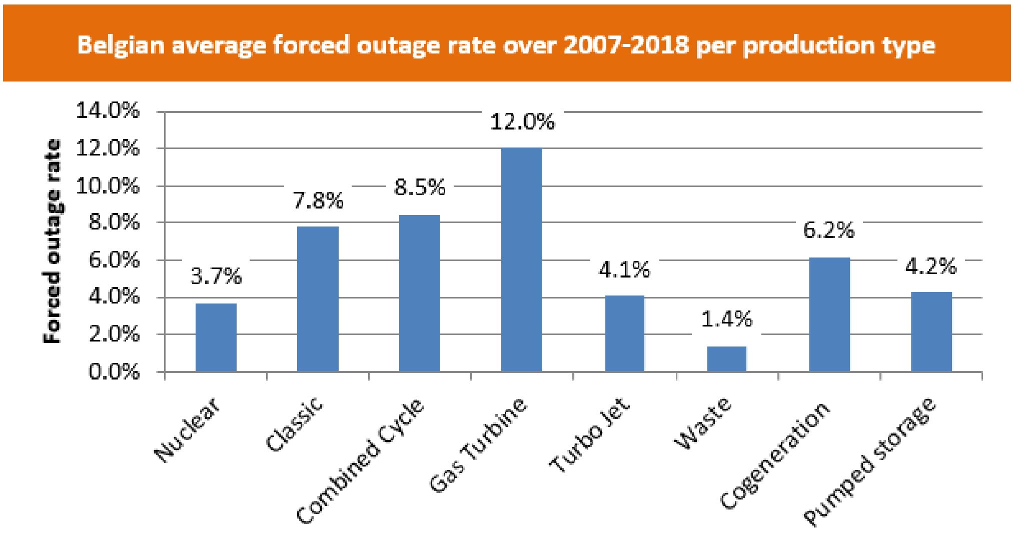


Figure 3.8

An analysis of the forced outage rates of Belgian generation units showed that they can differ greatly from one year to the next. In Figure 3.9 and Figure 3.10, this variability is illustrated for CCGT and nuclear units respectively. It can be observed that the forced outage rate for Belgian CCGT units has been dropping in recent years. One possible explanation for this is that older CCGT units have been taken out of operation.

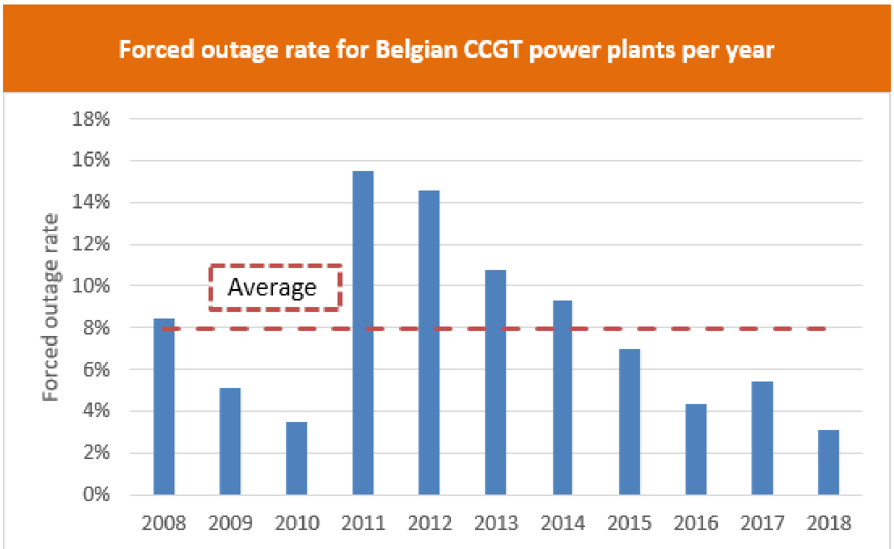


Figure 3.9

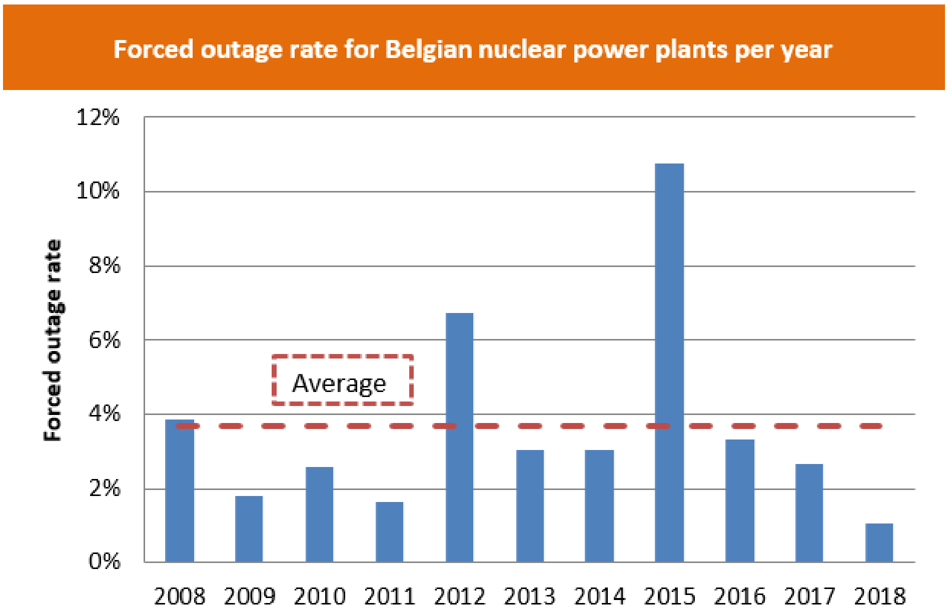


Figure 3.10

In addition to analysing the frequency at which unplanned outages affecting Belgian generation units occur, the outage duration was also modelled. For unavailability of a very short duration (i.e. intra-day outages), balancing reserves can be used (see section 3.1.5). Consequently, such outages do not need to be taken into account when calculating the required strategic reserve volume.

For each type of generation unit, the probability associated with the duration of an unplanned unavailability was modelled separately. An analysis of the historical durations of forced outages showed that unavailabilities usually lasting a limited number of days.

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 3.11 shows the result of the aforementioned exercise for 2019. 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.

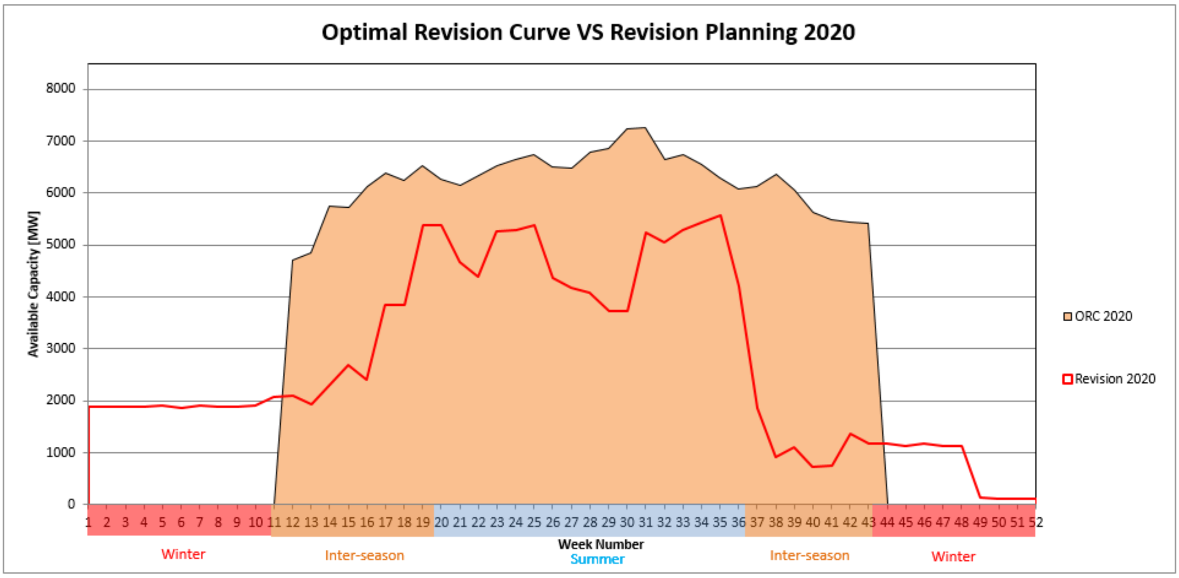


Figure 3.11

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 1,308 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 reduced by 500 MWh, lowering the available storage capacity available for economic dispatching to 5,300 MWh. Note that a 400 MWh increase in the Coo reservoir is expected by 2021. This will mean an available storage capacity of 5,700 MWh as of the second modelled winter.

In the ANTARES model, the 10 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). The power required by pumped-storage units to pump water into the reservoir can be considered additional consumption. Likewise, the turbining of water boosts Belgium's electricity generation. The historical use of pumped-storage power plants in Belgium is in line with the modelled results.

When the model encounters periods of structural supply shortage (i.e. when energy prices approach their price cap), the pumped-storage units are used at maximum capacity. If the supply shortage lasts longer, the model will dispatch the pumped-storage units in a bid to flatten peaks in electricity consumption.

Belgium's **run-of-river** power stations have a combined installed capacity of 151MW. According to the information available to Elia, an increase in this capacity is expected, resulting in an installed capacity of 180 MW by the end of 2023. As described in greater detail in section 8.1.1.2.4, run-of-river power stations are taken into account in the model based on monthly profiles for the past 33 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 about renewables.

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. 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. Elia will contract 78 MW of FCR in 2020. Nevertheless, starting from winter 2020-21, 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 2020-21, it is assumed that 150 MW will be provided by Belgian generation units. Given the specific requirements of this type of reserve, it is currently provided by Belgian thermal generation units, but there are plans to open up the aFRR market to all technologies in 2020.

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 395 MW for winter 2020-21.

For information purposes, Figure 3.12 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 [21].

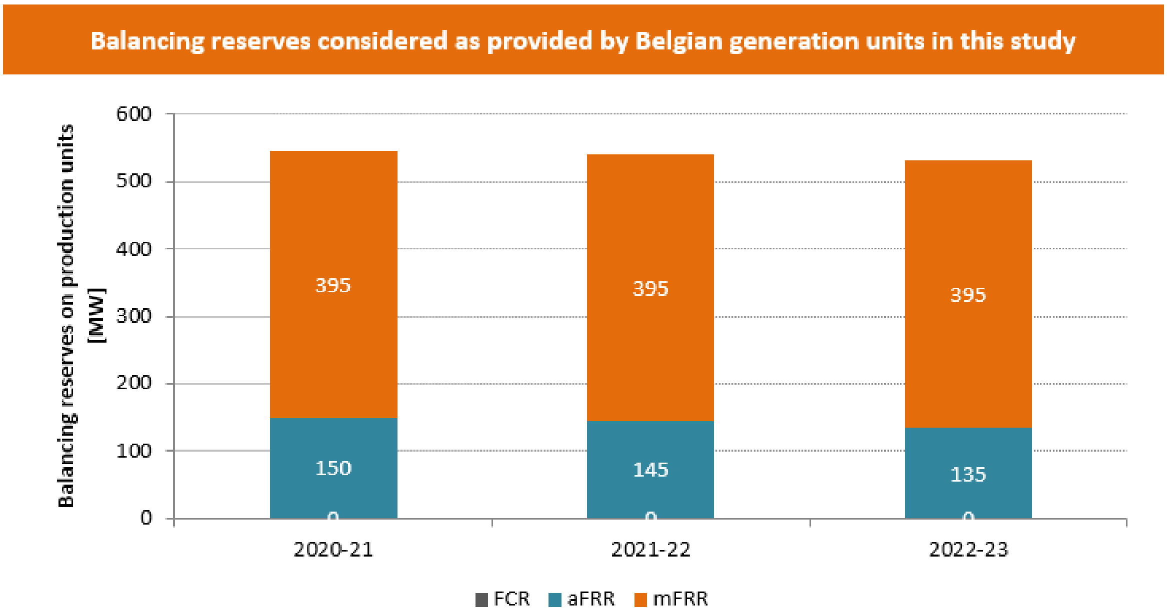


Figure 3.12

3.2 Electricity consumption in Belgium

As discussed in greater detail in the appendix (section 8.1.1.3), modelling electricity consumption consists of three steps (see Figure 3.13). This section outlines the assumptions taken for Belgium during each of these steps.

1. Growth of the total demand
2. Growth applied to an hourly profile normalised for temperature
3. Addition of the temperature sensitivity effect to the normalized load

Figure 3.13

This section provides an overview of the assumptions made with regard to Belgian electricity consumption. The modelling details are provided in the appendix in section 8.1.1.3.

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 dearth 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.

Decentralised 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 30kV 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 4.5.

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>do</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 [23].

3.2.1 Growth of Belgium's total load

For Belgium, the most recent forecast by IHS Markit, an internationally renowned consultancy agency, is taken as the reference for total demand for electricity in Belgium in this study. This forecast takes account of IHS Markit research on the underlying economic and policy drivers that affected the European power markets up to February 2019. The IHS Markit forecast was based on a multi-sector model in which the industrial and commercial sectors are by far the biggest drivers of incremental power demand in Belgium the years to come. This study considers relatively modest average growth of 0.42%/year.
Figure 3.14 gives an overview of annual total demand since 2011 and its value normalised for temperature. The table includes the 'base case' forecasts used both for this analysis and in the previous study from November 2018.

		Historical values			Base case normalized total demand		Forecast Nov. 2018
		Total demand [TWh]	Normalised total demand [TWh]	Growth rate	Growth rate	Forecast [TWh]	Forecast [TWh]
historical	**2011**	87.02	88.17	-1.00%			
historical	**2012**	84.86	84.66	-3.97%			
historical	**2013**	86.24	85.81	1.36%			
historical	**2014**	83.73	85.14	-0.78%			
historical	**2015**	85.01	85.64	0.58%			
historical	**2016**	85.02	84.86	-0.91%			
forecast	**2017**	84.826	85.38	0.61%			
forecast	**2018**				0.08%	85.45	85.88
forecast	**2019**				0.43%	85.82	86.45
forecast	**2020**				0.52%	86.26	87.08
forecast	**2021**				0.40%	86.60	87.62
forecast	**2022**				0.53%	87.07	88.05
forecast	**2023**				0.57%	87.56	

Figure 3.14

The values presented in table form in Figure 3.14 are also plotted as a graph in Figure 3.15, which clearly shows the relationship between measured and normalised historical demand.

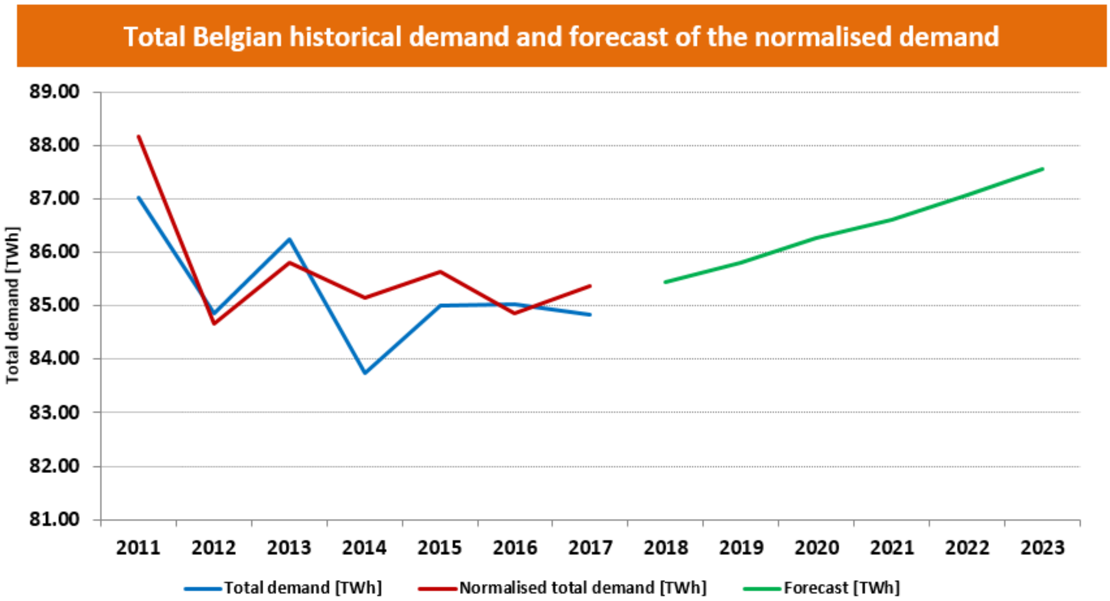


Figure 3.15

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. The hourly normalised profile for Belgium used in this study is shown in Figure 3.16.

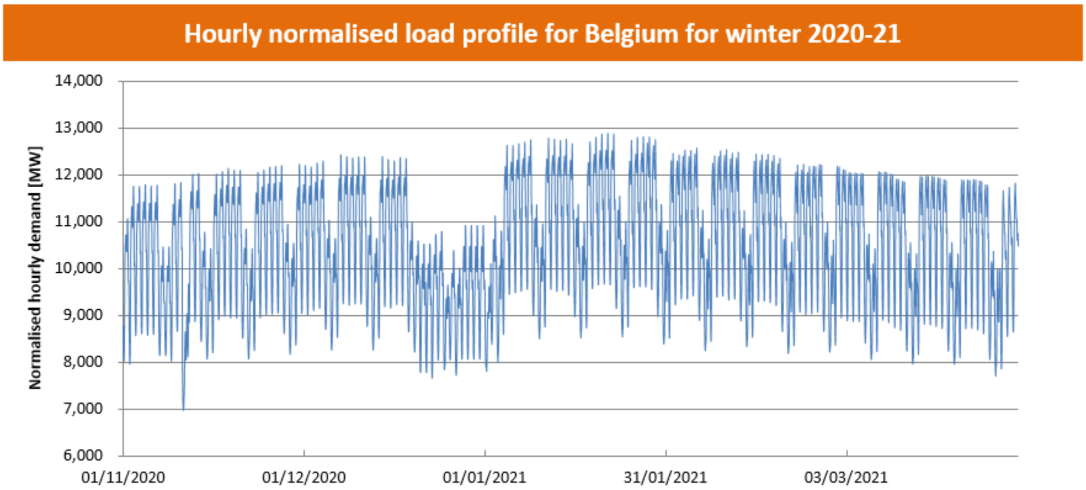


Figure 3.16

Figure 3.16 clearly shows the weekday/weekend and holiday effects on Belgian consumption.

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 3.17 shows the impact of temperature on the total hourly profile for Belgium for one of the 33 past winters used in this study.

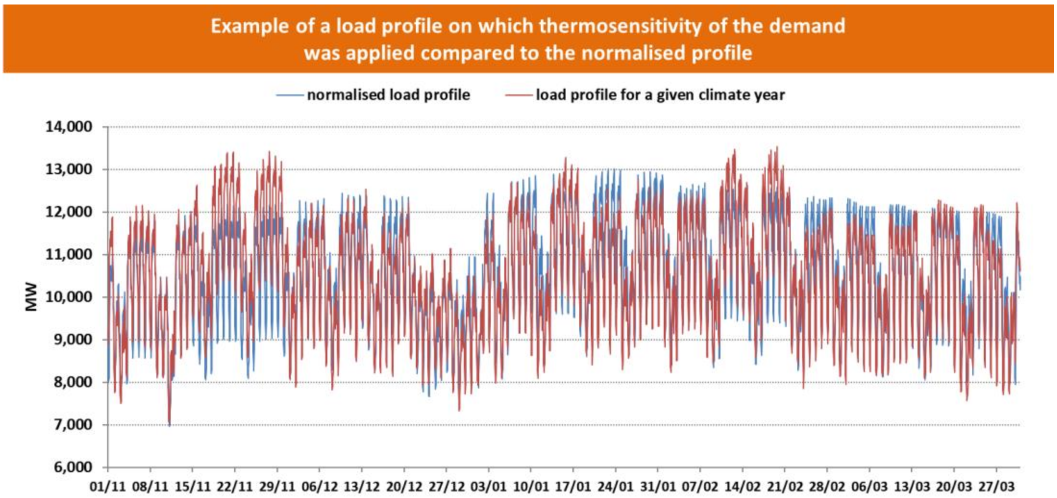


Figure 3.17

The method for taking account of load thermosensitivity was developed in the context of the ENTSO-E MAF study (see section 1.8.4) 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. More details of this method are given in section 8.1.1.3.3.

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 2020-21. 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 2020-21

Figure 3.18 gives an overview of peak demand after applying the thermosensitivity effect for the 33 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 3.18 shows a peak demand of 13.6 GW for the 50th percentile for the winter covered in this study (2020-21) – a probability of 'once every two years'. In extreme cases, peak demand could be even higher, 14.4 GW, as indicated by the 1 in 20 probability (95th percentile, probability of 'once every 20 years').

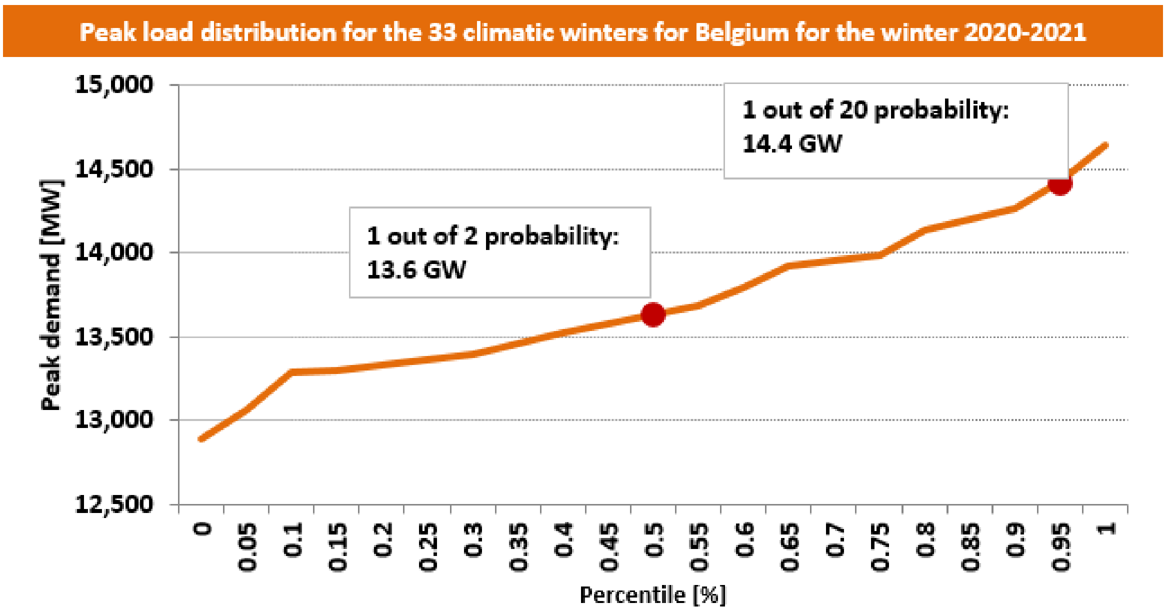


Figure 3.18

Figure 3.19 shows historical peak demand[17] between 2002 and 2017, 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 2020-21 as used in this analysis, whose range covers the observed historical peak demands.

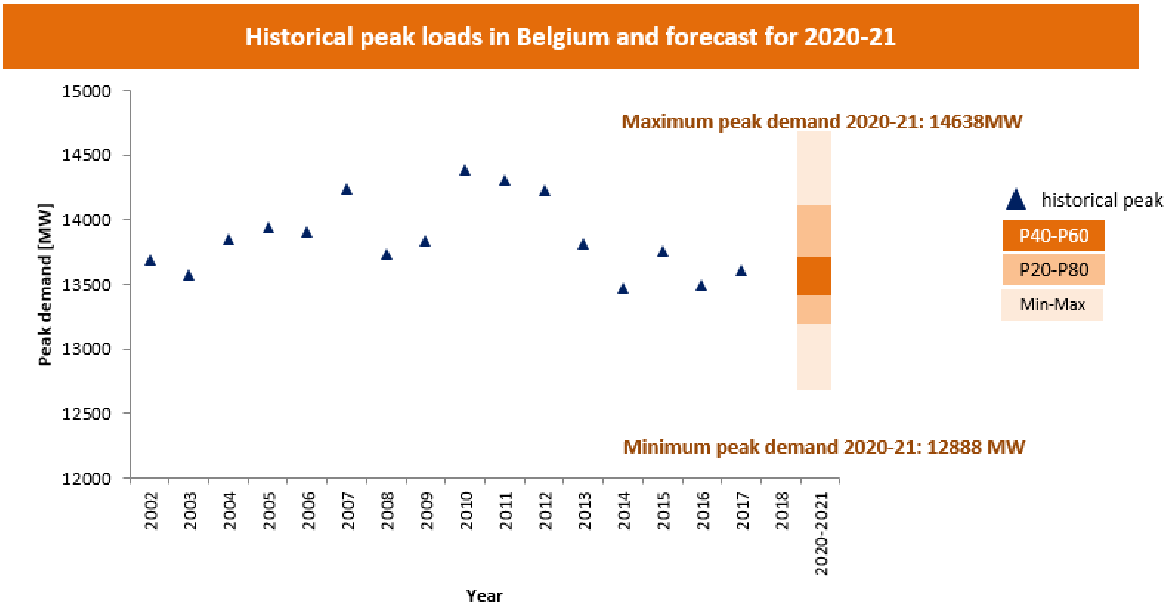


Figure 3.19

Peak demand in winter 2020-21 is forecast at between 12.9 GW and 14.7 GW, depending on climatic conditions.

3.3 Market Response in Belgium

This section discusses how this adequacy study takes account of the available market response in Belgium. As consumers may react when electricity is in scant supply by lowering their net consumption, it is important to take this response into account to avoid overestimating the strategic reserve needed. Section 3.3.1 provides a brief overview of how market response has been integrated in the past and of the procedure resulting in the development of the new method for correctly integrating market response into the process of determining strategic reserve volume. Section 3.3.2 then gives a detailed description of the newly developed method, together with the results obtained.

3.3.1 Introduction

Market response is a crucial dynamic parameter when difficult situations arise on the electricity grid, especially under demanding conditions when adequacy problems arise. European policymakers (2009/72/EC and 2012/27/EC), national politicians and regulators are all pushing for the further development of market response (MR). Their urging is echoed by the market stakeholders' call (flexibility-requesting parties (FRPs), BRPs, producers, suppliers, third-party

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

aggregators and customers) to fine-tune the methodology used to identify the volume of market response[18] in Belgium when determining the strategic reserve volume.

In 2015, Elia sent a questionnaire to BRPs, Elia grid users and/or aggregators to estimate market response at times of system stress. The survey investigated three types of flexibility through load reduction in the market: based on contracts, on prices and on a voluntary mechanism. The results focused on the flexibility available to market participants, not on the volumes that Elia can contract and activate when balancing reserves or drawing on the strategic reserve.

In 2017, a broad range of market players expressed their willingness to participate in developing a new method for determining market response in Belgium as part of the process for determining the strategic reserve volume. In January 2017, in the context of the Task Force 'Implementation Strategic Reserve', a Demand Response Study subgroup was set up to design the most appropriate methodology for determining these market response volumes. Its work was conducted together with E-CUBE Strategy Consultants. The method they designed was based on interactions with stakeholders over four workshops and bilateral interviews.

3.3.2 Development of a new method for determining market response volume

The market response used in the context of determining the strategic reserve volume, encompasses the full, energy-only market response when prices are exceptionally high. The market response under normal price conditions (i.e. prices < €150/MWh) is already taken into account in the normalised load profile constructed by Elia for its adequacy study. The newly developed methodology makes it possible to determine the market response volume available when prices are exceptionally high (> €150/MWh). The conclusion reached was that the method can estimate the market response across all different consumer segments.

Based on the workshops and input from consultants, it was concluded that the entire available market response can be taken into account by following the threefold approach set out below (see Figure 3.20). Global market response volumes can be estimated by analysing the aggregated demand and supply curve[19] of the EPEX Spot Belgium day-ahead market (section 3.3.2.1). This analysis was supplemented with a qualitative questionnaire to assess the activation details and lastly verified by performing a sanity check (section 3.3.2.2).

[18] DSR generally takes the form of lower consumption (not including distributed generation or storage technologies), whereas market response should be understood in a broader sense, leaving out the technology (including distributed generation or storage technologies). This adequacy study was based on a market response of the latter, broader type.

[19] An aggregated curve is a curve representing all demand offers, expressed in capacity, ranked from lower to higher price.

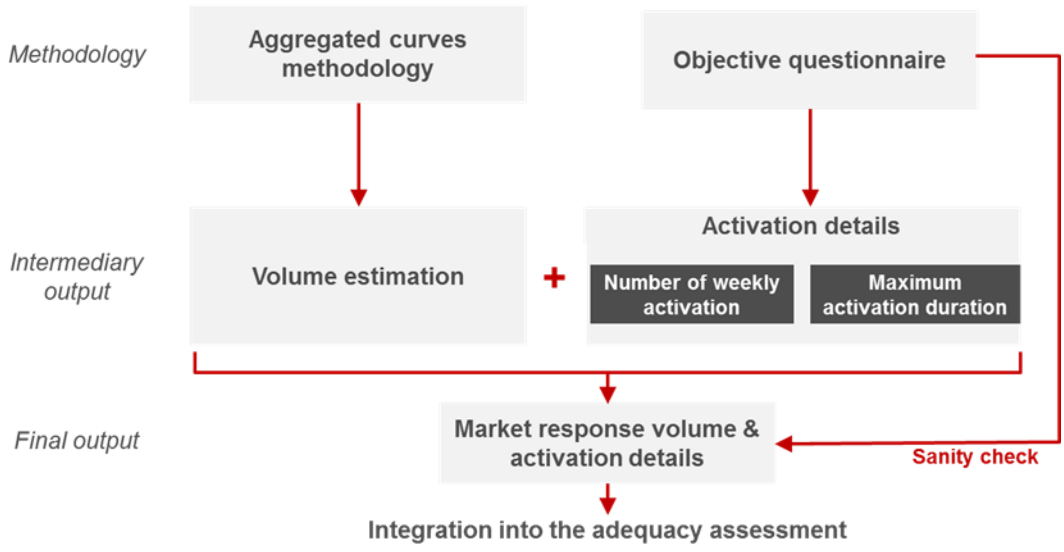


Figure 3.20

Section 3.3.3 summarises the results of the analysis and how they are to be integrated into the adequacy assessment. The methodological framework is considered robust for the coming years, though it could be regularly updated by repeating some analyses, as reflected in section 3.3.4. The final report based on this study can be consulted on Elia's website [43].

3.3.2.1 Aggregated curves- analysis: estimating global volume

Aggregated curves methodology enables the total market volume to be estimated for contract-based, price-based and voluntary market responses. In these aggregated curves, market response volumes can take the form of a drop in demand or an increase in supply.

The **drop in demand** due to a price increase is directly incorporated in the aggregated curves by studying the decreasing volume associated with the price increase from €150/MWh (the lower limit for market response volumes) to €3,000/MWh (the maximum day-ahead price), as is evident in Figure 3.21. Since aggregated curves are provided every hour, this volume comparison is also computed hourly.

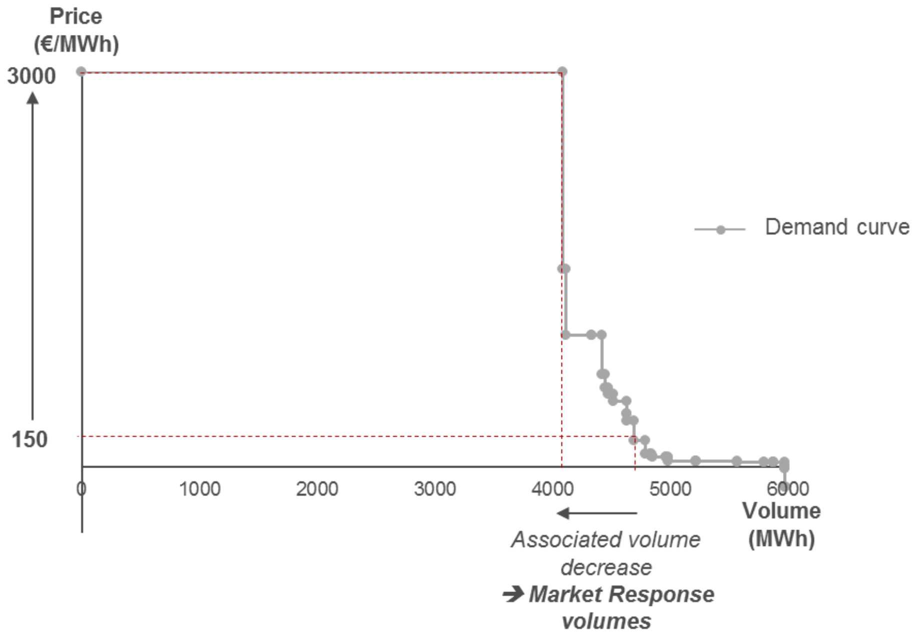


Figure 3.21

On the demand side, the output is the market response volume every hour.

For example, if 400 MW are above the €150/MWh limit, the estimated market response volume for that particular hour is estimated to be 400 MW.

Instead of a drop in demand, suppliers can value market response in terms of **increased supply** to the market. The market response cannot be directly deducted from these curves as they aggregate this capacity with generation. Contrary to demand curves, where the presence of bids representing reduced generation is considered very limited above €150/MWh, supply curves can contain generation bids in this price range. Generation bids higher than €150/MWh can be justified by extraordinary variable costs, such as foreign sourcing.

To refine the analysis of the supply curve, two price thresholds are considered (see Figure 3.22):

— **€150/MWh**: generally regarded as the limit bid for generation assets, even if some generation assets can justify higher bids in specific cases;
— **€500/MWh:** above this value, it is deemed very difficult to justify the price, and it can be assumed that only demand response bids will appear in the curves.

The analysis of supply-aggregated curves provides a range including:

— **a low estimate** for the supply side that does not take account of the potential value under €500/MWh, but definitely excludes generation;
— **a high estimate** that integrates the adequate scope of market response but may also take account of additional volumes of generation assets.

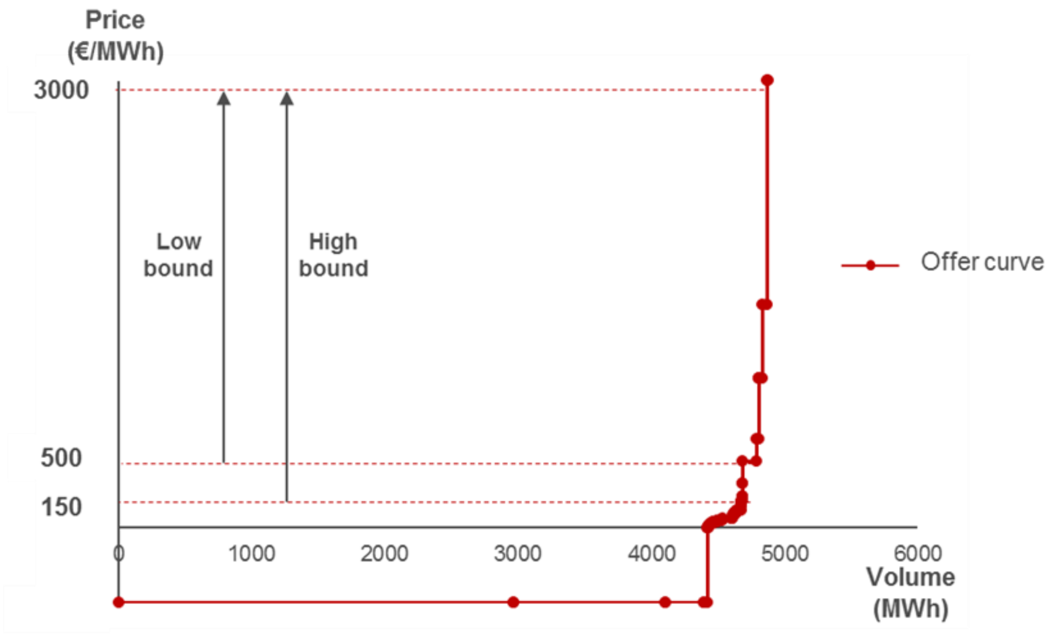


Figure 3.22

The aggregated curves do not take account of smart orders[20]. This could reduce the total estimated market response volume. However, the volume of market response smart orders is very limited, since most such orders are linked to generation assets. The impact on the assessment of market response volumes is very limited.

The curves do implicitly take account of over-the-counter (OTC) bids. If this volume would not be in the curves, it would correspond to irrational behaviour by the stakeholders, which was not taken into account in the study.

As an example, if the volume above €150/MWh is 150 MW and the volume above €500/MWh is 100 MW, the market response volumes presented as values in the supply curve can be considered to fall within the 100-150 MW range.

The volume obtained by following this method corresponds to the adapted scope for contract-based and price-based market responses, as well as the voluntary market response forecast by market players. If some volumes are in the voluntary market response category, the market players will anticipate such events. Theoretically, their anticipation should be reflected in bidding behaviour, if the BRPs deem the changes to be definite, with the voluntary market response then implicitly taken into account in this methodology. In general, this approach makes the methodology robust with an eye to future changes (e.g. new technologies facilitating market response), since any change that the market players deem or will deem to be firm will appear in the aggregated curves, and will therefore be considered in the analysis.

3.3.2.2 Global sanity check

To conduct a sanity check, the questionnaire also provided an estimate of current volumes. This effectively avoided the main limitation of the questionnaire raised by stakeholders: the description of hypothetical situations.

An international benchmarking exercise was conducted, putting market response volumes in proportion to maximum peak loads in the electrical system. These volumes were then compared to those previously established, to assess their global consistency.

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[20] Smart orders are either linked block orders (one block is executed if the other is) or exclusive block orders.

3.3.3 Results of the analysis and integration in the adequacy assessment

The **aggregated curves analysis** made it possible to estimate market response volumes. These volumes had first to be extracted from EPEX Spot Belgium day-ahead market aggregated curves to obtain a processable dataset of hourly market response values from 01/01/2014 to 05/04/2019. 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.

The refined dataset was then analysed to assess the impact on market response volumes of various parameters, including temperature, price and Elia's grid load. Although regressions did not reveal any statistical correlations between market response volumes and these parameters, another analysis showed that Elia's grid load has the greatest impact on market response volumes. Indeed, during high-load periods, the dataset's standard deviation is reduced and its average volume increases. Consequently, volumes for winter peak hours were extracted, so that high-load hours could be examined separately. For the refined dataset, the average volume during winter peak hours totals 699 MW.

Finally, the extrapolated output was applied to the three next winters (i.e. 2020-21, 2021-22 and 2022-23).

In line with the progressive approach towards MR evolution in last year's assessment, Elia will proceed with a 7% growth rate, which is exceeding any of the 3 proposed growth rates by E-cube. By applying a growth rate, no lower than last year's growth rate, to which most stakeholders positively responded, Elia anticipates that the historical data from winter 2018-19 could have been an outlier.

Market Response volume [MW]	Measured	Extrapolation			
			Winters under consideration		
	2018-19	**2019-20**	**2020-21**	**2021-22**	**2022-23**
7% growth	699	764	845	924	1010

Figure 3.23

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 [10] published in June. 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 3.24 An activation price between 300 and 2000 €/MWh was used.

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 3.24

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 detailed analysis of how the market's response is used in the simulations is provided in section 6.2.3.

3.3.4 Methodological updates

Elia is actively analysing the method in order to evaluate the effect of recent evolutions in the electricity market, such as a multiple NEMO context, or a growing importance of block bids. In case of significant impact on the MR results, changes to the methodology will be proposed with the aim of obtaining even more representative results. However, the methodological framework itself, defined together with market parties, may be considered robust for the years to come. The quantitative method facilitates an annual recalculation based on updating the data and parameters, without necessitating an annual redesign of the methodology. The EPEX Spot Belgium day-ahead market's aggregated curves should be updated by adding recent data every year, along with price thresholds, the extrapolation factor and ancillary service changes. Note that new market changes impacting the aggregated curves will automatically be incorporated in the analysis.
However, the qualitative methodology is less sensitive to annual changes and is also more resource-intensive for Elia and market parties. An update of the qualitative aspects could be planned after a few years or whenever the need becomes apparent.
In any event, Elia chose to only update the quantitative aspect of this method to analyse the market response available for determining the strategic reserve for winter 2020-21.

3.4 Summary of electricity supply and demand in Belgium

Figure 3.25 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 generation capacity in the market (excluding units in strategic reserve)		Production capacity in winter available in the market [MW]				
		2018-19	*2019-20*	2020-21	2021-22	2022-23
Non RES	Nuclear	5,919	5,943	5,943	5,943	4,957
	CCGT/GT/CL	4,893	4,807	4,807	4,807	4,807
	CHP	1,933	1,984	2,145	2,145	2,145
	Turbojets	176	176	176	176	176
Storage	Pumped-storage	*1,308*	*1,308*	1,308	1,308	1,308
RES	Waste	318	313	313	313	313
	Biomass	794	793	745	758	775
	Run of river hydro	114	151	171	176	180
	Wind onshore	2,284	2,370	2,608	2,726	2,840
	Wind offshore	1,051	1,610	2,253	2,253	2,253
	PV	3,932	4,384	4,965	5,303	5,639
	TOTAL	*22,722*	*23,839*	*25,434*	*25,907*	*25,393*

Figure 3.25

Figure 3.26 was put together by combining the installed generation capacity with the P90 peak demand forecast in Belgium for winter 2020-21. 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). Moreover, it should be noted that comparing the shown P90 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.

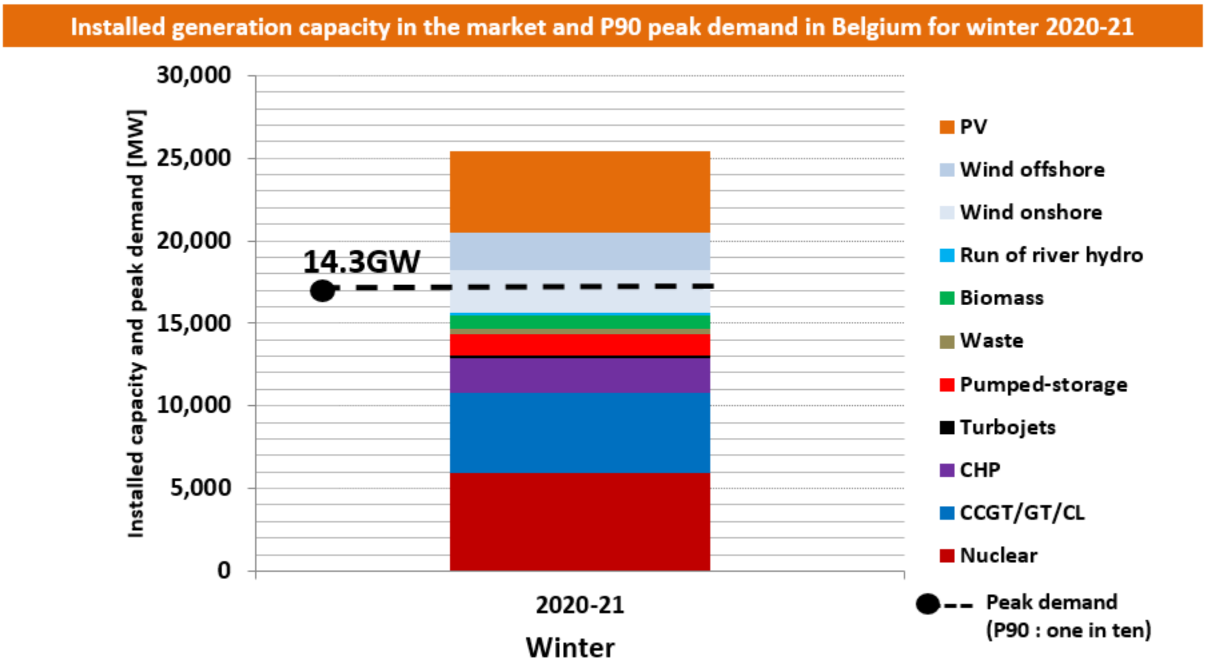
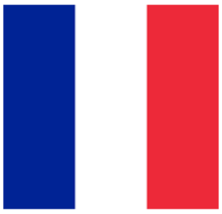

Installed generation capacity in the market and P90 peak demand in Belgium for winter 2020-21
Installed capacity and peak demand [MW]
30,000
25,000
20,000
15,000
10,000
5,000
0
14.3GW
2020-21
Winter
PV
Wind offshore
Wind onshore
Run of river hydro
Biomass
Waste
Pumped-storage
Turbojets
CHP
CCGT/GT/CL
Nuclear
Peak demand
(P90 : one in ten)

Figure 3.26

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 1.8 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 France



The nuclear capacity is excpected to be below the level of winter 2019-2020 for the first two winters (2020-21 and 2021-22) with the decommissionning of Fessenheim and the delay in the Flamanville EPR commissioning that is expected for winter 2022-23.

An analysis of the observed nuclear availability of the last five winters in France was performed in order to define a sensitivity scenario considered in this assessment.

Over the past several years, stabilisation of demand in France is observed mainly due to energy efficiency measures and moderate economic growth. It is expected that demand will slightly decrease for the next coming winters.

The assumptions for France are based on the data collected for the MAF2019, complemented with recent developments or announcements on existing and new capacity. The latest adequacy report (*Bilan Prévisionnel*) issued by the French transmission system operator (RTE) takes also those recent developments into account and provides a very detailed view on French adequacy.
Figure 4.1 provides a 'base case' overview of installed capacity in France for winter 2020-21. P90 peak demand is also indicated.

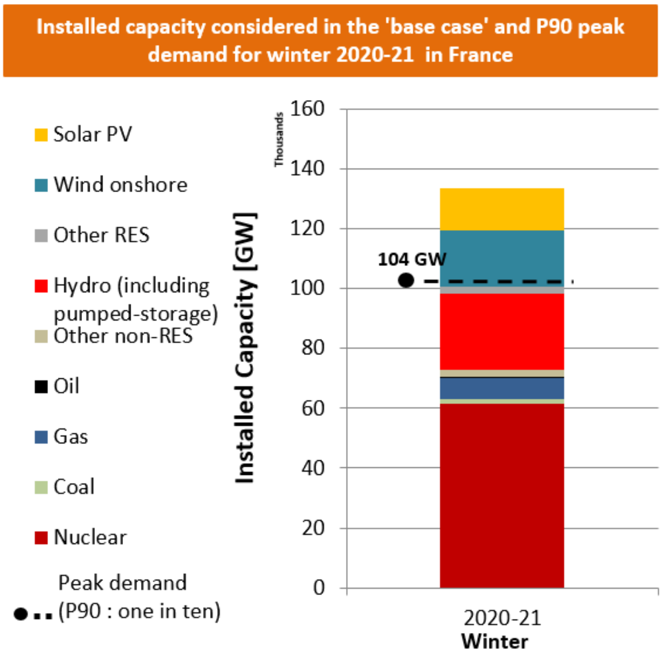


Figure 4.1

4.1.1 Electricity supply in France

4.1.1.1 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 winters included in the assessment;

— coal-fired units are continually decreasing and will be completely decommissioned by winter 2022-23 given coal phase-out announcements;

— decentralised thermal generation is expected to remain in the market

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

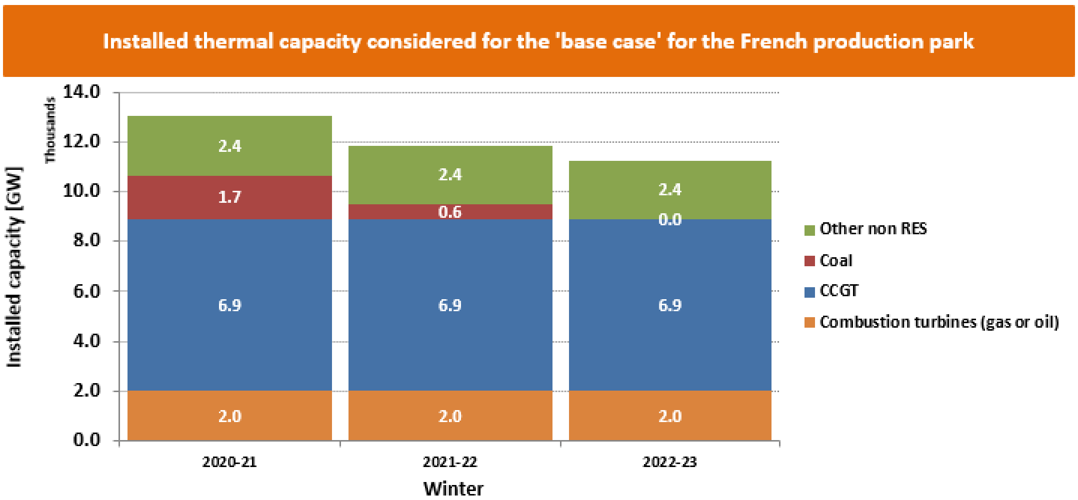


Figure 4.2

4.1.1.2 Nuclear capacity

The French generation fleet is mainly composed of nuclear capacity which accounts for around 63 GW (including Fessenheim). With the exception of Fessenheim, which will close in 2020, the French government has decided to maintain the current nuclear fleet until 2025. The oldest units are going to reach 40 years of operation in the coming months. Each nuclear unit has to follow a major inspection called the *visite décennale* (VD). Given the large number of units in France (58), multiple units undergo this inspections every year. In June 2019, the Tricastin 1 reactor was the first one to start the fourth VD. There are always uncertainties around 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 several months. Such uncertainties are tackled in the 'High Impact, Low Probability' scenario. Note that, in parallel, a new EPR unit is being built in Flamanville. While previous studies assumed it would be available for winter 2020-21, recent announcements of additional delays due to welding problems mean this assumption is no longer valid. This study therefore assumes that Flamanville will be commissioned before winter 2022-23 in this study. This will increase the total nuclear generation capacity by 1.6 GW for the last winter studied. Figure 4.3 summarises France's installed nuclear capacity.

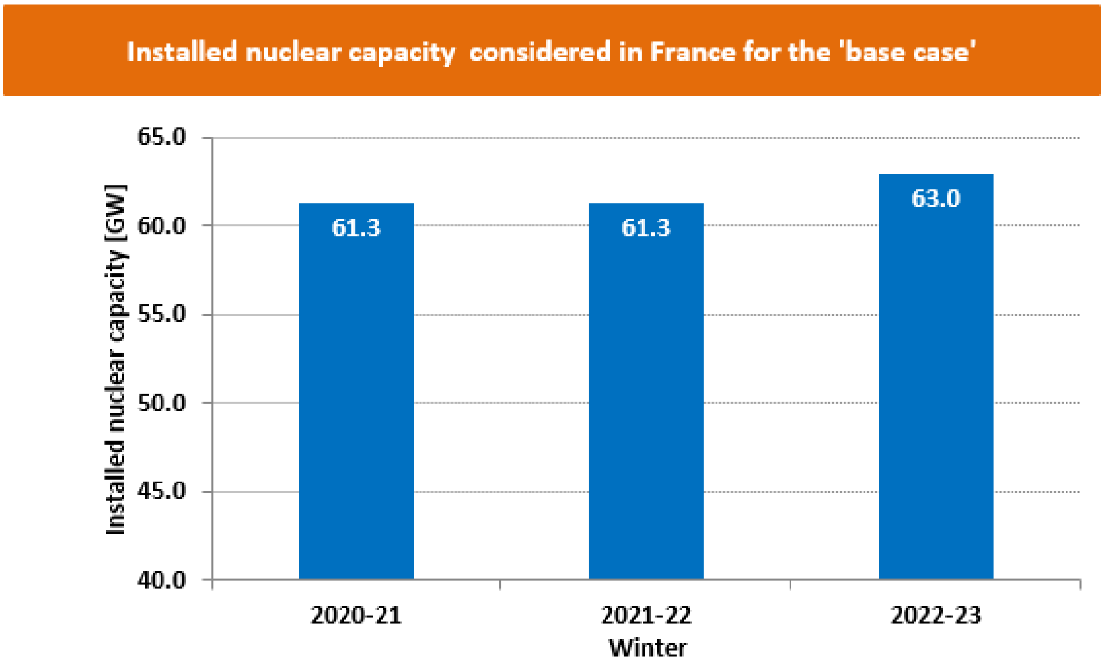


Figure 4.3

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 followed 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 2019, providing 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. Furthermore, an analysis of historical availability in France over the past seven winters was performed to determine unavailability in France corresponding to 'high-impact, low-probability' sensitivity analysed in the study (see section 6.3.1 for details).

4.1.1.3 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 counted 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 2022.

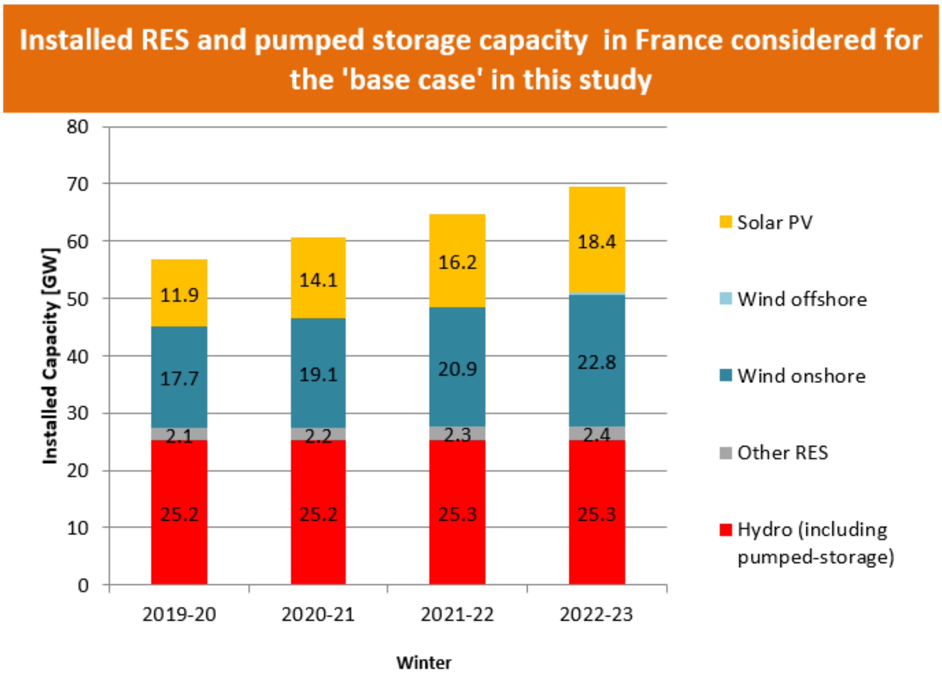


Figure 4.4

4.1.2 Electricity demand in France

Over the past few years, RTE has noted a stabilisation 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.

The Energy Transition Act of 2015 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 the 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 penetration of electrical heating in the country [27] [28] [29].

For this years' analysis, the same method for modelling load thermosensitivity for France was applied again. It is also in line with the method used by RTE in its adequacy report for 2018 [25].

The market response expected in France mainly corresponds to demand-side management of around 2.7 GW.

4.1.3 Security of supply in France

The adequacy report by French TSO RTE studies the situation for France [25]. The next such report (BP2019) is scheduled for publication in mid-November.

Furthermore, France has had a capacity mechanism (CM) since 30 November 2016 [48], which is organised as a decentralised capacity market designed to ensure compliance with the reliability criterion set by the French authorities (an LOLE of 3 hours per year).
This mechanism rewards operators for feeding available capacity into the electricity system when the supply is tight, and is intended to provide economic signals complementing those emanating from the energy market.
The French capacity mechanism applies across the energy market, with all participating generators of capacity allowed to be involved. A clear distinction is drawn between the energy market and the capacity market. Indeed, generators with certified capacity will only be required to make that capacity available, but will still be able to decide not to generate energy based on the order of merit. Consequently, the capacity mechanism is effectively designed not to alter market participants' bidding strategy and dispatching decisions in the short term.

4.2 The Netherlands

Bilateral communication with TenneT NL TSO indicates that, the Netherlands can ensure their adequacy solely by relying on domestic power production for winter 2020-21.

Taking into account the expected reduction in operational thermal production capacity, TenneT NL TSO confirms that the Netherlands might have to rely on imports for their security of supply, but only around year 2025.

The assumptions made in this study for the Netherlands are collected through the ENTSO-E PEMMDB database used in the Mid Term Adequacy Forecast (MAF) 2019 ENTSO-E report and bilateral contacts with Dutch TSO TenneT NL. They are also in line with those used for the Dutch national adequacy study, *Rapport Monitoring Leveringszekerheid 2019* (due to be published in December 2019). Figure 4.5 indicates the assumptions used for the Dutch electricity supply and demand for winter 2020-21. Sections 4.2.1 and 4.2.2 elaborate on supply and demand in the Netherlands respectively.

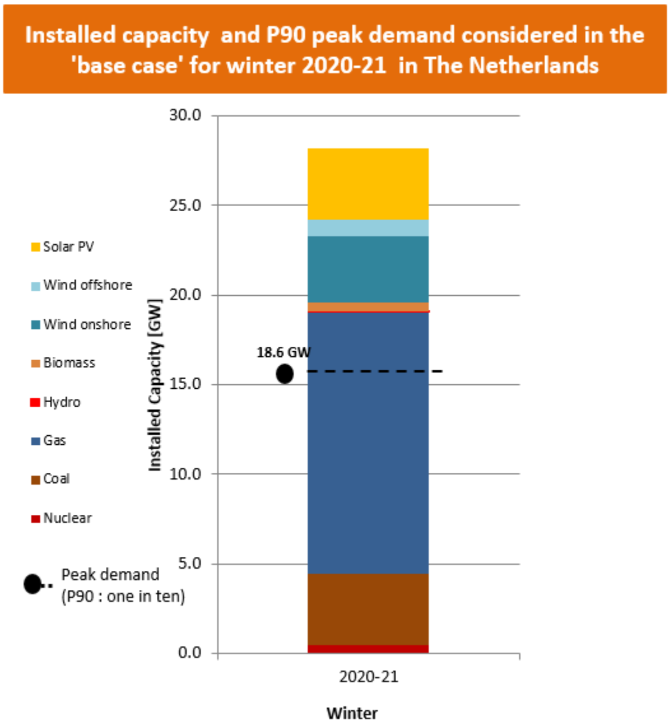


Figure 4.5

4.2.1 Electricity supply in the Netherlands

4.2.1.1 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 closure of 3 GW of **coal capacity** in the past 5 years. The Dutch government is pressing ahead with its plans [46] to close all other coal-fired power plants by 2030. A planned closure relevant for this study is the closure of the Hemweg-8 unit (630 MW by 2020). However, hereafter Coal-fired power is expected to remain at the current level, generating approximately 4.0 GW in all winters under consideration.

As in other European countries, Dutch **gas-fired** power plants have faced challenging economic conditions in recent years. Several gas-fired plants have announced temporary mothballing (i.e. shutdowns). Some of them only shut down during the summer (summer mothballing), and are thus taken into account in the analysis concerning the winter only. Some recent changes have occurred in the availability of Dutch gas-fired power plants. The mothballing of Moerdijk 2 has been revoked. Accordingly, the unit is considered available for all winters. It is worth noting that the Maasbracht Claus C CCGT unit is now expected to come out of mothballs as of late 2020. For this reason, Elia assumes Claus C will be available in all winter models for this year's volume assessment. This unit, with a capacity totalling over 1.3 GW is responsible for the increase in gas generation as seen between 2019-20 and 2020-21 in Figure 4.6. This assumption is to be considered with caution, especially for winter 2020-21. The Eemshaven CCGT4 unit is scheduled to be decommissioned in early 2021. This unit is therefore excluded from the listing as of winter 2021-22 onwards. Furthermore, the decommissioning of Lelystad-4 will lead to a further reduction in gas-fired capacity. As it is currently scheduled in the second part of winter 2022-23 the effect of its decomissioning is not shown in Figure 4.6.

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 timeframe of this study. No new Dutch nuclear power plant projects are expected.

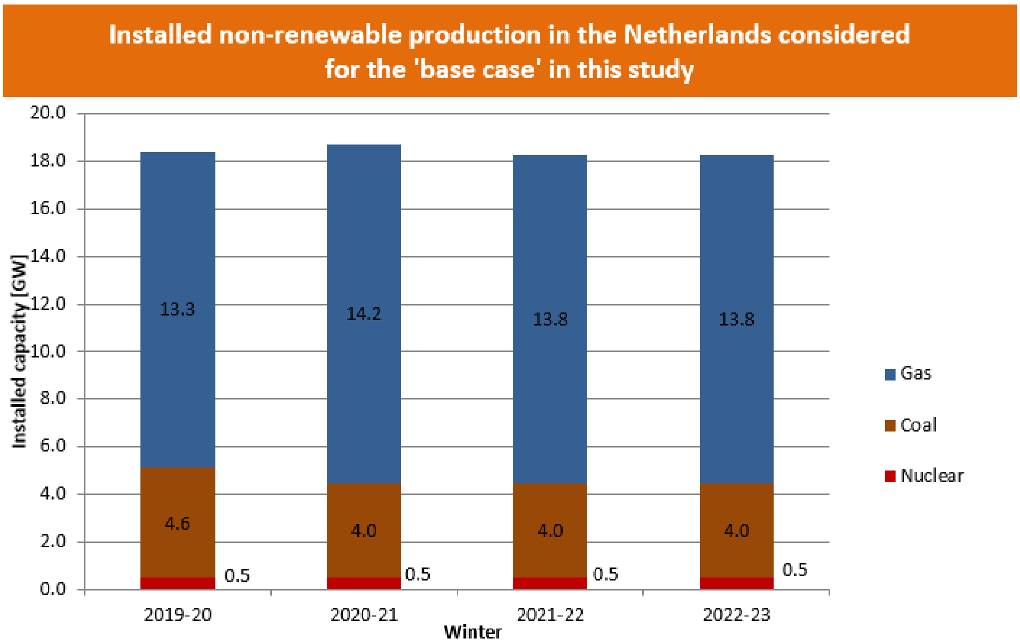


Figure 4.6

4.2.1.2 Renewable electricity generation

On 29 June 2019, the National Climate Agreement (*Nationaal Klimaatakkoord*) was presented by the Dutch government [54]. This agreement builds on previous climate legislation, namely the Energy Agreement for Sustainable Growth (*Energieakkoord voor duurzame groei*) [37].

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 after consideration of the National Climate Agreement.

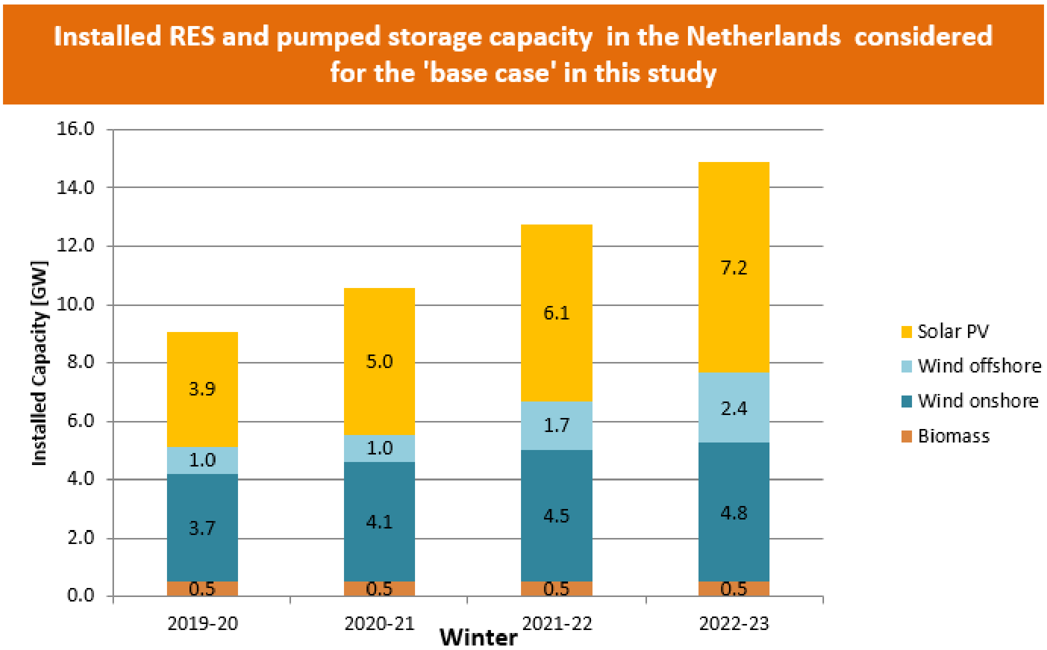


Figure 4.7

4.2.2 Electricity demand in the Netherlands

Assumptions about electricity demand in the Netherlands are in line with the latest Dutch adequacy report (to be published in December 2019), as estimated by Dutch TSO TenneT NL. Electricity demand normalised for temperature is expected to remain relatively stable during the period under analysis.

As announced in last year's 'monitoring Levenzekerheid 2018' report, TenneT is currently analysing to what extent DSR is available. An optimistic best estimate, taking 40% of all must-run other non-res generation (mainly small CHP's), is taken for **demand-side response** capacity in the Netherlands. This was suggested by TenneT TSO in the context of the MAF 2019 data collection. The corresponding total demand-side responds thus totals to **1780 MW.**

4.3 Germany

Germany has a high RES penetration but also high 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' recommendation.

Germany has a comfortable margin when scarcity occurs in Belgium and France because of its large amount of possible imports from the north and the east, and its diversified domestic production park.

The German nuclear phase out is on track with more than half of the installed capacity in 2010 already taken out of service and only 7 more nuclear power plants remaining.

The 1400 MW Nordlink interconnector is taken into account as of winter 2021-22.

The assumptions about Germany made in this study are based on data compiled from the 'Systemanalysen der übertragungsnetzbetreiber' [30], the 'Netzentwicklungsplan' (NEP) scenario B [31] published at the beginning of 2019, bilateral contacts with German TSOs, the recommendation to close all coal and lignite capacity in the coming 20 years from the 'Growth, Structural Change and Employment' commission (also called 'Coal Commission') and the 2019 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 2020-21. Germany's electricity supply is discussed in greater detail in section 4.3.1. German demand is discussed in section 4.3.2. Finally, Section 4.3.3 discusses the coal phase-out in Germany and its potential impact on Belgium.

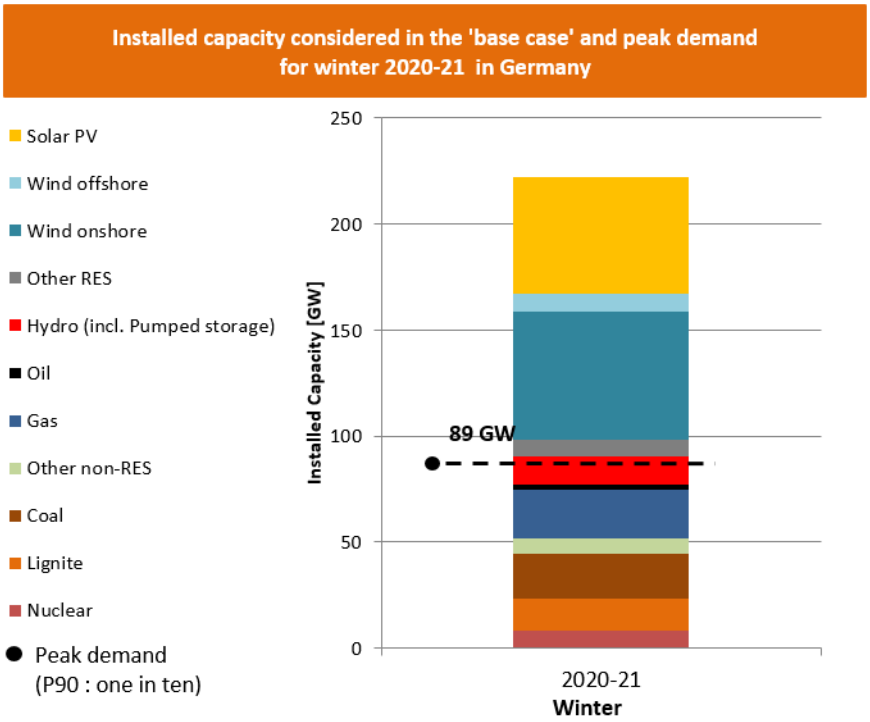


Figure 4.8

4.3.1 Electricity supply in Germany

4.3.1.1 Non-renewable electricity generation

The assumptions made about non-renewable electricity generation in Germany are illustrated in Figure 4.9, showing 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 key points in 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. In total, this amounts to a nearly 10 GW reduction in installed nuclear capacity already. The next nuclear power plants scheduled to be shut down are Philippsburg 2 by the end of 2019, and Grohnde, Gundremmingen C and Brokdorf by the end of 2021 [41]. Finally, Isar, Neckarwestheim and Emsland are to be decommissioned by the end of 2022. It is important to note that Figure 4.9 shows nuclear units as available as long as they are still in service on 30/12 of the given winter.

Today, almost 20% of the electricity generated in Germany is fuelled by **coal and lignite** [49]**,** down from 43% in 2015 [50]. A significant drop in the installed capacity of German coal and lignite production is expected, due partly to environmental policies, but also to government plans to phase out coal-mining subsidies. These plans are detailed in section 4.3.3. Nevertheless, in Germany at Datteln, E.ON is currently building the only coal-fired power plant under construction in Western Europe. With a nominal capacity of just over 1 GW and an commissioning planned for 2020, this power plant is taken into account in all of the three analysed winters.

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

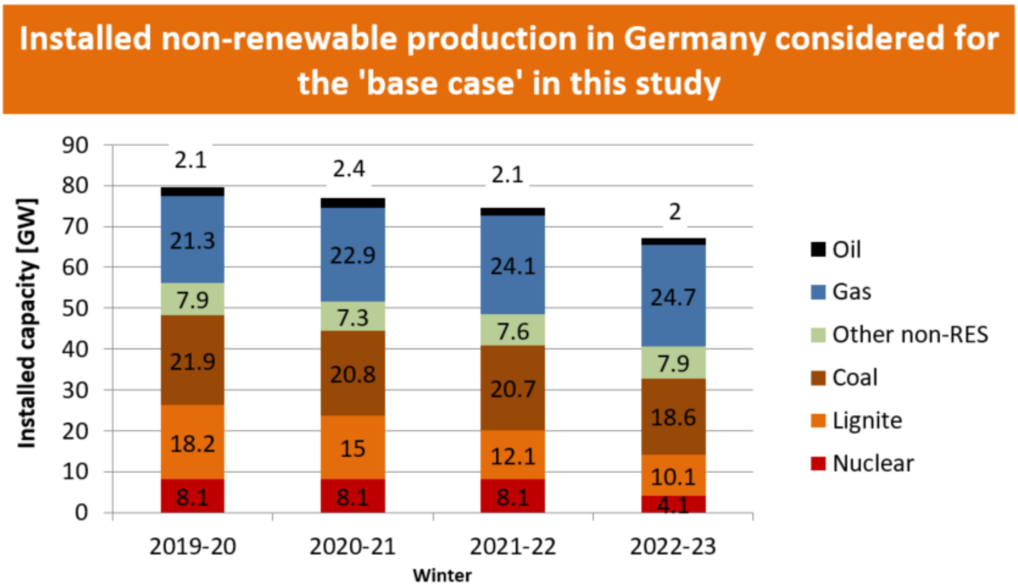


Figure 4.9

4.3.1.2 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 & hydro capacity over 140 GW for winter 2020-21.

The data on renewable generation capacity in Germany are in line with the ENTSO-E 2019 mid-term adequacy forecast (MAF).

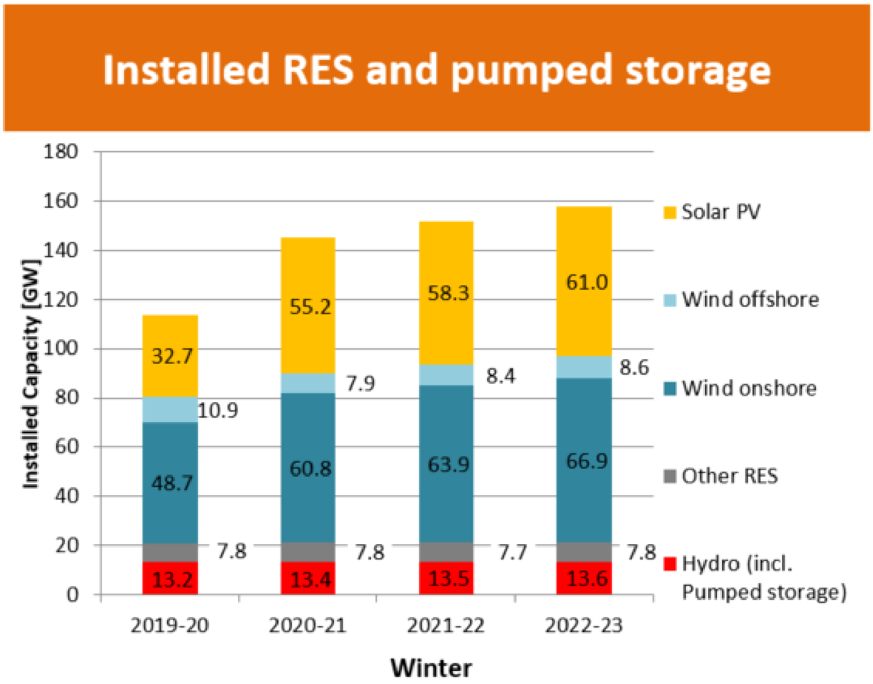


Figure 4.10

4.3.2 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. The German load is expected to drop from 530 TWh/year in 2018 to 528 TWh/year in 2025. This slight decrease is due to increasing energy efficiency in line with the attainment of political objectives (the 2025 total load values are in line with NEP).

The assumption made about German market response in this study is in line with what German TSOs communicated to ENTSO-E in the context of the MAF, which in turn is in line with NEP 2019 scenario B. Whereas for 2018 0 MW was reported, for 2025 a 1.3 GW German market response share was estimated. Through interpolation a market response share of 0.589 GW was found for winter 2020-21.

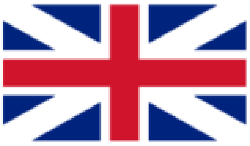
4.3.3 Germany's coal phase-out and its impact on Belgium

There are currently 43 GW of coal-fired power plants installed in Germany. Following the Coal commission's recommendation, it is proposed to reduce this capacity to 30 GW by 2022, 17 GW by 2030 and close the remaining units by 2038 (or 2035).

This highlights one of the major differences compared with past adequacy studies. For winter 2020-21 this resuls in over 4 GW of additional decommissioned coal capacity, compared to the already decreasing capacity as reported in last year's volume assessment.

This is also in line with the 'low carbon' sensitivity that was simulated within the framework of the ENTSO-E MAF 2018 study, where around 8 GW of coal capacity was removed in Germany.

4.4 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.

In its 'Winter Outlook Report 2019-20', the British ESO National Grid indicates that no security of supply problems are expected for winter 2019-20.

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 CHP projects and other small -scale non renewable generation.

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 2019 and other European studies released by ENTSO-E. Those assumptions follow the 'Steady Progression' scenario from the 'Future Energy Scenarios' (FES) produced by National Grid in July 2018 [22]. The FES is a report published by British ESO 'National Grid ESO' describing a set of scenarios up to 2050. The discrepancies between installed capacity and demand in the different scenarios detailed in the FES report are limited in the short term [24].

The British government's 2013 Energy Act [38] 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 greater detail in section 4.4.3. The CfD mechanism provides incentives for low-carbon electricity generation capacity.

Section 4.4.1 sets out the assumptions made with regard to the electricity supply for Great Britain. Section 4.4.2 details the demand-related hypotheses used in this analysis.

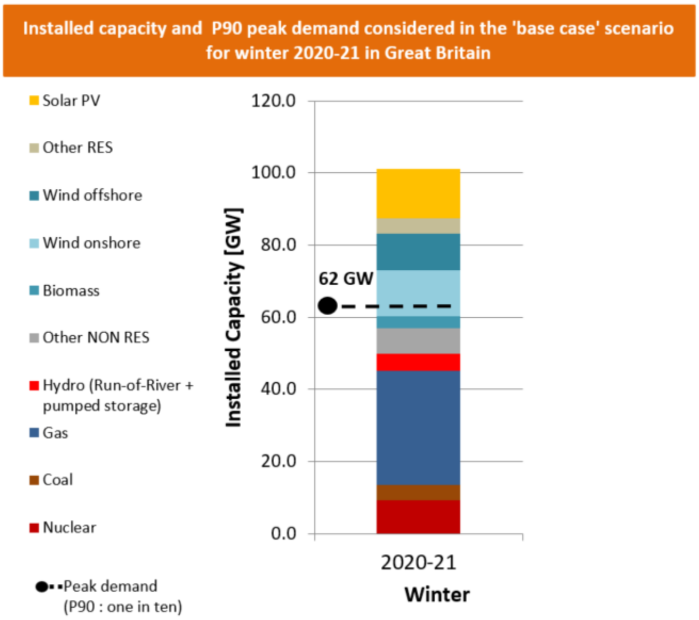


Figure 4.11

4.4.1 Electricity supply in Great Britain

4.4.1.1 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 British government introduced a carbon price floor (CPF). Initially, this mechanism aimed to bring about a carbon price of £30/tCO_2 by 2020[21], but in 2016 it was modified to limit its impact on British competitiveness [39], [52].

Figure 4.12 shows the assumptions made about Great Britain regarding 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 to a 2015 level of 17.3 GW. The installed capacity of coal-fired electricity production is expected to continue falling over the coming winters, albeit non linearily, and reach 2.8 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 closure of older units is being partially offset by additional CHP projects and other small-scale non-renewable generation, leading to a decreasing level of gas-fired generation for winter 2022-23. Regarding British nuclear generation units, it is expected that 2 GW of existing capacity (Hinkley Point B and Hunteston), will be decommissioned beginning 2023 (e.g. during the winter period 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.

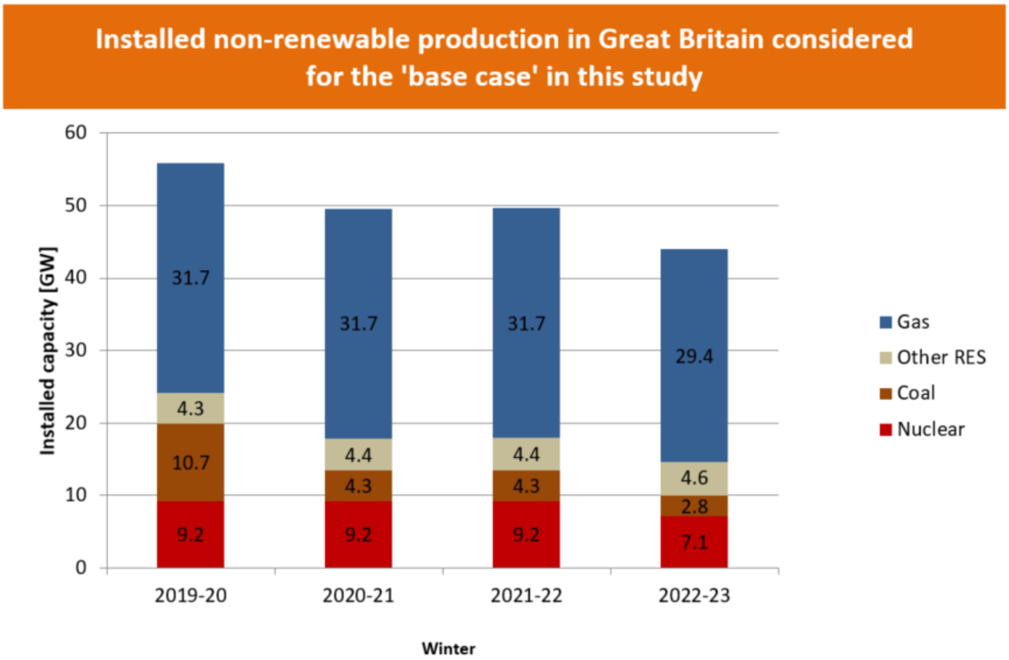


Figure 4.12

4.4.1.2 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)

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

mechanism introduced in the 2013 electricity market reform. The installed capacity of offshore wind is expected to increase by more than 4 GW by winter 2022-23, compared to winter 2019-20. For photovoltaic and onshore wind production limited increases in installed capacity of roughly 5% and 2% respectively are expected for the same period. No significant change is expected during that time for biomass, hydropower and other renewable generation capacity.

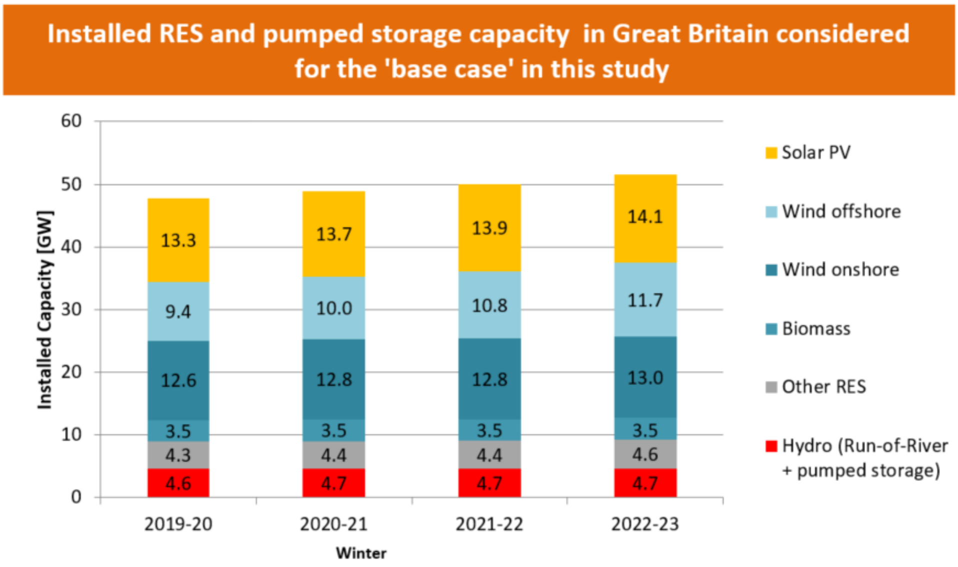


Figure 4.13

4.4.2 Electricity demand in Great Britain

The total electricity demand assumed in this study for Great Britain is in line with the steady progression scenario set out in the 2018 FES report [22]. This scenario envisages pretty stable normalised annual demand up to 2022, as in three of the four 2018 FES scenarios. The 2018 FES two degrees scenario is the only one that envisages a slight increase in demand due to the very rapid electrification of transport.

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 2019.

4.4.3 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. A recommendation about the capacity to contract is made using a least worst regret (LWR) method that considers multiple scenarios (including the FES scenarios) and sensitivities. Subsequently, it is up to the government to decide on the details of the capacity market auction.

The first CM auction was held in December 2014 for delivery in winter 2018-19. For winter 2017-18, capacity was auctioned via an 'early auction' held in February 2017 and a 'transitional auction' held in March 2017.

The latest report analysing medium-term security of supply in Great Britain is the *Electricity Capacity Report 2019* [40] submitted to the British government by National Grid in May 2019. That report recommended the capacity market volume to be secured for winters 2020-21 (T-1) and 2023-24. Making only minor adjustments [45], the British government followed the recommendation made by National Grid. The auctions designed to guarantee capacity for winters 2020-21 and 2023-24 took place at the start of 2018.

The last CM auction, held on 8 February 2018, secured around 50 GW of capacity at a relatively low price of £8.40/kW for delivery in 2021-22. This year's auction signifies a major shift away from coal, with 8 GW of existing coal plants not securing agreements via the auction. Existing gas and nuclear facilities, new interconnectors and decentralised energy are expected to fill the gap [55][56].

On 15th November 2018, the General Court of the European Union has decided, to annul the European Commission's decision not to raise objections to the aid scheme establishing a 'capacity market' in the United Kingdom. The ruling has resulted in the suspension of the UK's 'capacity market', thus preventing the government from holding future auctions or making payments under existing agreements. On October 2019, the Secretary of State for Business, Energy and Industrial Stategy has notified to National Grid Electricity System Operator (ESO) and the Electricity Settlements Company (ESC) that the trigger for the resumption of capacity payments has occured. These entities are required to restart all Capacity Market functions that had been suspended during the standstill period [57][58].

Winter Outlook Report 2019-20

Source: National Grid ESO (10 October 2019)

We expect there to be sufficient operational surplus for each week of winter 2019/203. Normalised peak transmission demand is expected to occur in the first half of December and the operational surplus is also projected to be lowest at this time. [...]

We expect net imports of electricity on interconnectors from continental Europe to GB for most of the winter. We expect to typically export from GB to Northern Ireland and Ireland during peak times.

4.5 Luxembourg

Modelling the situation in Luxembourg is important for Belgium because part of that country is connected to the Belgian control area (the 'LUb' zone in Figure 4.14). In 2016, the CCGT plant in Luxembourg but belonging to the Belgian control area was shut down definitively [42]. Since that closure, the LUb zone has only included consumption. 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;
- The IC BeDeLux project, which physically connects the LUb and LUg zones, is not taken into account in this study. See section 5.2.2.2.5 for more information.

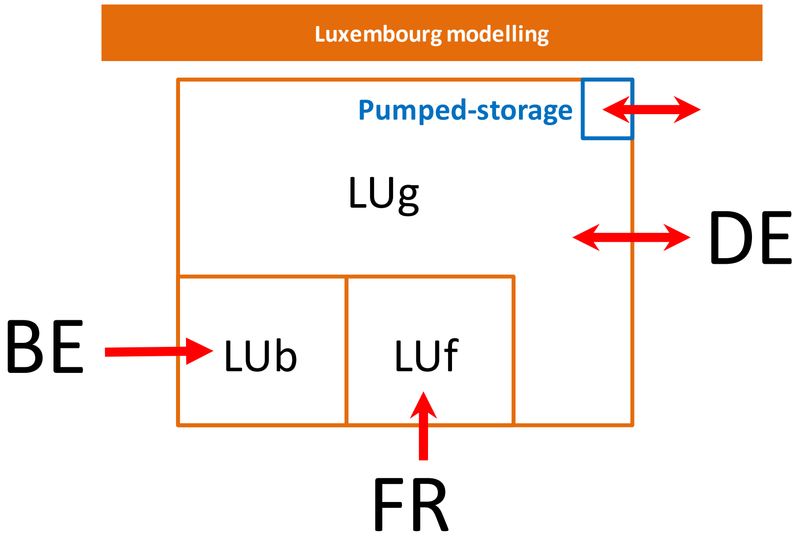


Figure 4.14

4.6 Other countries modelled

This study models 20 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 2020 and 2025 (see section 1.8.4 for more information), ENTSO-E transparency platform [24], ENTSO-E statistics [26], bilateral contacts, PLEF adequacy study and national reports and statistics.

4.7 Accelerated decommissioning of conventional generation

As was illustrated in the previous sections of this chapter, Western European countries are evolving at great speed towards a domestic production fleet which is based on much more renewable energy generation, and much less conventional generation.

In the period from 2019 to 2022, conventional generation is planned to rapidly decrease. **Indeed, around 35 GW of conventional generation is planned to disappear in CWE countries alone** as detailed below.

Belgium will see a decrease of **1 GW** with its first decommissioning of a **nuclear** power plant. Between 2022 and 2025 another **5 GW** is scheduled to close.

France is decommissioning all of its **coal-fired** generation, totalling **3 GW**. In addition, the Fessenheim 1 and Fessenheim 2 nuclear plants, totalling **1.8 GW** are scheduled to close in 2020. While some investments are being made in new conventional generation, such as gas (Landivisau power plant under construction) and nuclear (Flamanville 3, under construction), the latter has been delayed many times, and the former's new gigawatts do not add up to the amount of coal-fired power decommissioned.

In the **Netherlands**, while some existing gas-fired power plants are scheduled to be decommissioned (Lelystad, Eemshaven), others have revoked their closure or will be coming back on-stream in the years ahead. However, coal-fired power is decreasing until 2030, by which time all **4.6 GW** of coal-fired generation will have been decommissioned. Even faster trajectories are being followed in Germany and Great Britain. In **Germany**, in the period from 2019 to 2022, **11.4 GW** of coal and lignite power is scheduled to close, as well as **8.1 GW** of nuclear generation. Countermeasures invovling new-build gas-fired plants are nowhere near matching these volumes.

In **Great Britain** coal is rapidly disappearing, with **7.8 GW** scheduled to be decommissioned between 2019 and 2022. During that same period **2 GW** of nuclear generation is scheduled to be closed. Additionally, the net sum of new built and closing gas-fired generation will total to a net decrease of **2.3 GW** of installed capacity.

Moreover, whereas last year's volume assessment showed the same trends, this year's assessment - updated with the latest projections from the neighbouring TSO's - clearly marks an acceleration in the decommissioning of old conventional generation units and at the same time a delay in the commissioning of new units, or the de-mothballing of recently closed units. Even though a comparison is not straightforward,[22] when the most up-to-date assumptions for winter 2020-21 are compared to those assumptions from last year's strategic reserve report, the projected installed capacity of conventional generation plants in 2020 has decreased by roughly 7 GW in Great-Britain, 4 GW in Germany and 1.6 GW in France. This **accelerated decrease** of projected conventional generation capacity, totalling **over 12 GW** compared to last year's assessment is crucial in the understanding of the results for winter 2020-21 as presented in chapter 6.

[22] Data sources can change from year to year, depending on which provides the most recent data. Additionally, different data sources define different data collection categories. Smaller units sometimes end up in bulk categories, whereas other times they are individually registered. Within one study edition however, the same data sources are used thus ensuring consistency.

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 is expected by 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 currently done on the day-ahead market:

— Commercial exchanges **inside the CWE** region are taken into account using the same **flow-based** methodology in the actual 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 further described in sections 5.1 and 5.2 respectively.

— Exchanges between **other countries and the CWE zone** are modelled with **fixed exchange capacities** (also called NTC – Net Transfer Capacities). See section 5.3 for more information.

Figure 5.1

5.1 Flow-based in the CWE zone

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

As Belgium is at the centre of the CWE zone, the country's import and export capabilities are currently heavily defined by the flow-based methodology used at regional level for the day-ahead markets. Belgium's net position is therefore linked to the net position of the other countries in the CWE zone and to the flow-based domain defining the possibilities of energy exchange between those countries. It is therefore critical to replicate market operation 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 moments when both France and Belgium are in structural shortage, Belgium's achievable imports can be significantly reduced. 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 of introducing a flow-based approach into the market coupling.

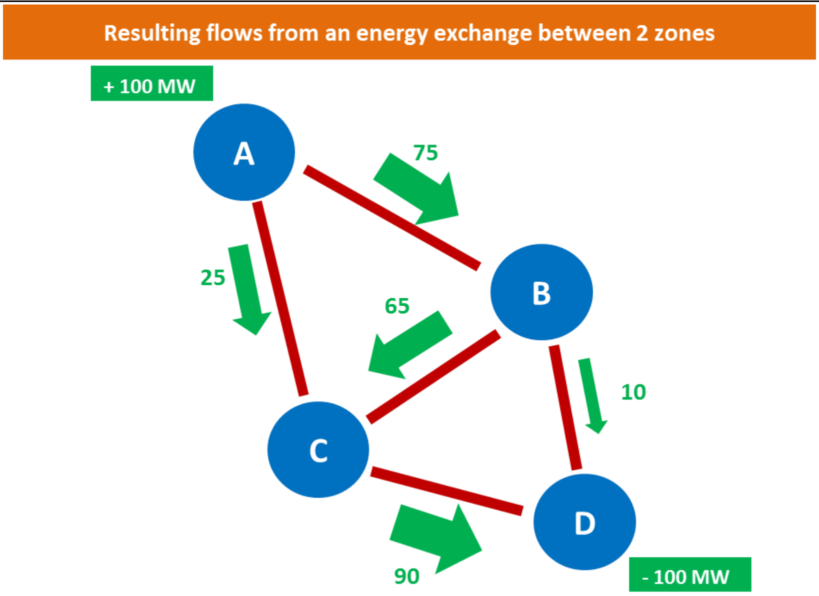


Figure 5.2

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

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) [34].

More information about the flow-based rules and methodologies is available from JAO resource center [35] and EPEX Spot Belgium [36].

The flow-based method implemented in day-ahead market coupling uses Power Transfer Distribution Factors (PTDF factors) 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 '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 (CNEC's) therefore 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 CWE 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 CWE 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 location of available generation units can vary.

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 with the increased 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 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.

The adequacy patch

The CWE flow-based algorithm includes an 'adequacy patch' defining rules for sharing energy exchanges in scarcity situations.

If a country has a structural shortage (day-ahead price reaches price cap in that country) the market does not necessarily dispatch all available energy to that market zone. Instead, the market tries to optimise the global welfare. Due to flow factor competition it might be more beneficial to dispatch energy elsewhere, thereby freeing up transmission capacity on another border, where in turn additional exchanges can lead to the generation of additional welfare. In such a situation the adequacy patch ensures that the maximal feasible import capacity will be allocated to the country in need, regardless of any destroyed welfare. This is called 'local matching'.

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 a quadratic function defined in the Euphemia market coupling 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.

5.1.3 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 without impact on the flow-based domains, 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 [32];
2. imports or exports over the Nemo Link® interconnector [33]

The additional voltage regulation possible thanks to the ALEGrO project, combined with investments in additional capacitor banks will enable Belgium to increase its maximum simultaneous import capacity to **6500 MW** in the assessment for winter 2020-21 and 2021-22.

In its Federal Development Plan [59] Elia envisages a further increase in the maximum simultaneous import capacity to **7500 MW**. Accordingly, Elia uses 7500 MW as the maximum simultaneous import capacity figure for the entire assessment for winter 2022-23.

5.2 Flow-based adaptation in the simulations

5.2.1 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 CWE countries that replicates the day-ahead operation. Whereas in the first flow-based assessment of winter 2016-17 only 1 domain was used to represent all of 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 reinforcements.

Introduction of the 'minRAM20%' in the flow-based market coupling algorithm

During 2018, CWE NRAs asked CWE TSOs to implement a 20% minimum Remaining Available Margin (minRAM20%) for the day-ahead flow-based market coupling (FBMC). The agreed minRAM20% level equals 20% of the Fmax (the maximum allowed power flow), applied on each Critical Network Element and Contingency (CNEC). The feasibility of the minRAM20% application is verified by TSOs for each business day. The go-live of the minRAM20% implementation happened on 24 April 2018 in D-2 (for FBMC Business Day 26 April 2018).

The minRAM20% process is applied to provide a minimal flow-based domain to the market. The minRAM20% is applied using the AMR (Adjustment for Minimum RAM) attribute of each affected CNEC which guarantees a minimal RAM per CNEC. The implementation of minRAM20% provides more capacity for commercial exchanges and thus potentially lowers the need for strategic reserves.

The effect of minRAM20% is taken into account as a baseline assumption in this and any further assessment performed by Elia regarding the volume assessment for strategic reserves, since this feature is currently operational in the capacity calculation of the FBMC framework.

For this reason it is currently impossible to change the minRAM applied to historical domains. As the SPAIC historical domain clustering process is the current provider of flow-based domains for short-term adequacy studies and this for all three of the winters under consideration in this volume report, the outlook winters 2021-22 and

2022-23 are also using minRAM20% domains even though the CEP action plan may aim for other virtual margins (as a general rule one could state that CEP requires a minRAM70% (simplified assumption) to be applied to all critical network elements in the flow-based calculation).
Notwithstanding the daily verification of minRAM20% feasibility by the TSOs, it is assumed that, especially if any country suffers severe adequacy issues, all efforts will be taken to ensure the application of the minRAM20% principle. However, the validity of this statement for minRAM70% should not be taken for granted.

Building on the experience of the previous assessments for winters 2016-17 untill 2019-20, the methodology for the winter 2020-21 assessment was again improved (see Figure 5.3). This time three major improvements can be distinguished:

- The most recent historical domains starting from the go-live of the DE-AT split on 1 October 2018 have been considered;
- The domains have been recalculated to consider the planned HTLS upgrade of the 380kV Belgian backbone;
- the ALEGrO interconnector is modelled as an additional degree of freedom of the flow-based domain.

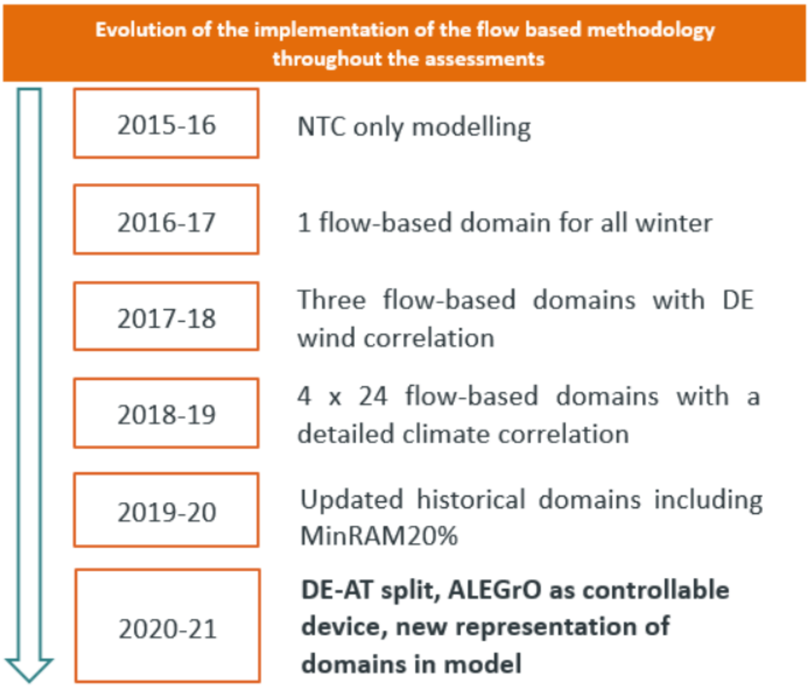


Figure 5.3

These modifications will be elaborated on in section 5.2.2.2.

German - Austrian bidding zone split

Capacity calculation with separate German and Austrian bidding zones is operational since 1 October 2018. The practical consequence is that the CWE net position of Austria can change independantly from the CWE net position of Germany. In this year's set of historical data sufficient domains are available in order to perform the clustering into typical days.

5.2.2 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.

5.2.2.1 Selection of typical days

In the context of the SPAIC CWE flow-based expert group, a statistical analysis of the geometrical shapes of historical flow-based domains was performed. These data are taken from the FB CWE operational tool.
The historical days are clustered using a k-medoid algorithm in families defined by the size of their 24 hourly domains. A medoid algorithm guarantees that the centroid domain corresponds to a real historical domain and is therefore realistic. For the algorithm to work, a new algorithm for typical day clustering, which required the definition of a dissimilarity metric between higher dimensional polytopes, was tried and tested, resulting in the successful clustering of historical days 1/10/2018 to 15/3/2019 into four winter days.
Each typical day consists of 24 hourly domains (one for each hour).

- A typical day is the historical day within a given family or cluster of domains which provides the best representation of all the other days in the cluster.
- Since flow-based domains are hourly, this typical day is selected by comparing its domain at every hour to the other day's equivalent domain (at the same hour).
- As a consequence of the increase in dimensions, the domains are no longer automatically clustered into visibly large, medium and small domains, but rather show 'preferences' in certain market directions. Additionally, the introduction of the minRAM rule sets a lower limit to the domain size, leading to less variability in the outcome of the cluster process.

The result of this typical day selection process is a set of 12 typical days. These can be divided in three groups per season (summer, winter, midseason) each consisting of four typical days. These four are further divided into one representing the weekends and holidays, and three representing the weekdays.

5.2.2.2 Modification of the input hypotheses for the typical days to account for new grid & market configurations

As a next step, the data from the operational framework is then manually modified to account for changes in grid topology or market rules.

5.2.2.2.1 Historical outages are removed

The flow-based domains considered are computed with the current operational rules and include an N-state and N-1 state computation. The starting N-state taken into account for this computation is the one of the historical day. Therefore maintenance or outages known when the domains were computed as well as the topology of the grid are taken from the historical days.

5.2.2.2.2 Future outages may be introduced

Furthermore flow-based domains could also be adapted according to planned grid outages, should they be planned in the relevant period for the assessment. Changes to the historical domains might be thus applied in some cases, in order to match the conditions of the grid. Additionally, all nuclear units will be set to maximum output in the historical day files that are used to construct the flow-based domains.

5.2.2.2.3 Future grid investments are taken into account

The domains have been recalculated to consider the planned HTLS upgrade of the 380kV Belgian backbone. The following circuits have thus been adapted:

- 380-73 Horta (Zomergem) – Mercator (Kruibeke)
- 380-74 Horta (Zomergem) – Rodenhuize
- 380-74 Mercator (Kruibeke)– Rodenhuize
- 380-101 Horta (Zomergem) – Avelgem
- 380-102 Horta (Zomergem) – Avelgem

5.2.2.2.4 ALEGrO

The planned HVDC interconnection with Germany (ALEGrO project) has a target commissioning date of late 2020 and it is assumed to be operational in all winters of this year's strategic reserve volume assessment.
As the ALEGrO interconnector is a controllable device, this adds another degree of freedom to the flow-based calculation, resulting in a 6-dimensional flow-based domain. Note that while the theoretical representation in Figure 5.4 adds two virtual hubs, these are in fact bound by a kirchoff constraint, thus adding only one degree of freedom.
The implementation of ALEGrO in the flow-based domains was performed for all winters in this year's volume assessment.

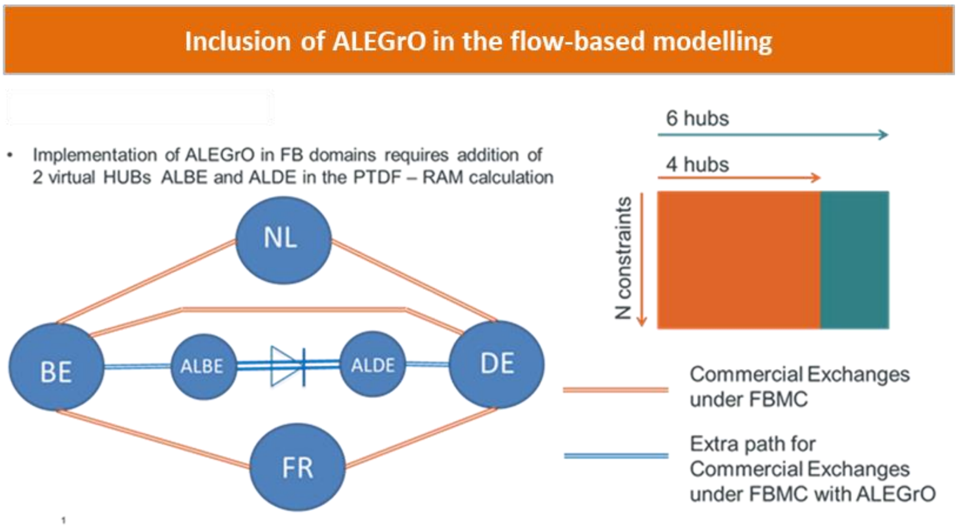


Figure 5.4

5.2.2.2.5 IC BeDeLux project

The phase shifter transformer (PST), located in Schifflange and connecting the Elia grid to the Creos grid, began its technical go-live on 11 October 2017 with a one-year technical trial period. After the first phase of the technical trial period an assessment was made by the project to evaluate whether new insights were gathered that would make it possible to start commercial operation of the interconnector earlier than planned. This first trial phase was summarised in a report sent to the NRAs assessing the approved operational principles based on the collected data. The IC BeDeLux project (Amprion, Creos and Elia) launched a new SPAIC study to assess whether changes in the constraints and/or available PST taps for capacity calculation in Day-Ahead (DA) would impact welfare. The SPAIC study showed a neutral impact on regional welfare due to the limited use of the interconnector. Accordingly, the project parties decided that the interconnector would not start commercial operation.

The PST is therefore not included in the SPAIC typical days used as input for this study.

5.2.2.2.6 minRAM

Finally, a minimum Remaining Available Margin (RAM) of 20% of the Maximum Flow (Fmax) will be also considered for each Critical Network Element and Contingency (CNEC), when assessing the FB domains to be used in the assessment.

5.2.2.3 Calculation of the new flow-based domains

When the modification of the input files is ready, the operational flow-based calculation process is mimicked, to compute new flow-based domains that are compatible with the new grid & market rules.

5.2.2.4 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 French TSO RTE (see reference documents [51] and [52]), 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 [16].

This method can be understood as follows. The k-medoid algorithm, as described in 5.2.2.1, not only selects the typical days representing the clusters, but also identifies for each historical day the cluster to which it belongs. Additionally for each historical day, climatic data are 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 typical day. Alternatively, one can identify the probability of finding either one of the typical days given a set of climatic conditions. It is this interpretation that is used when mapping the typical days onto the Monte Carlo scenarios.

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.

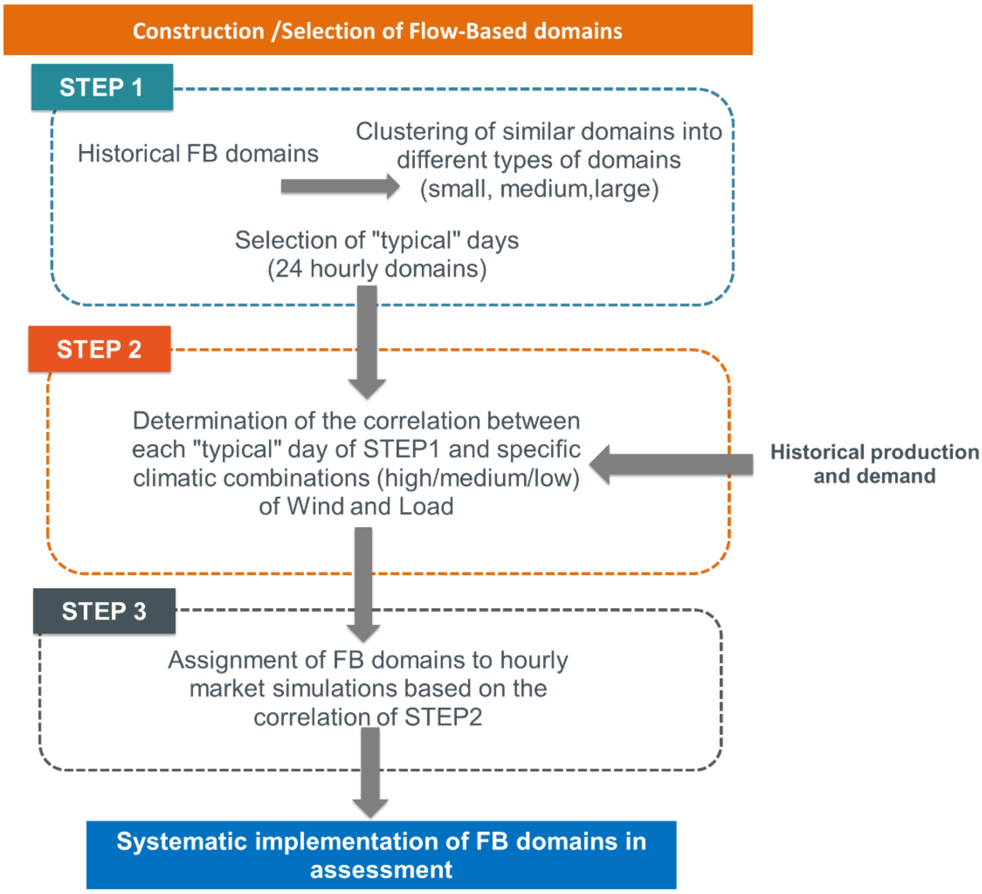


Figure 5.5

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

The relevant typical days found by the clustering procedure explained above for the winter period are:

- Flow-based typical day 1: 28 November 2018 (weekday)
- Flow-based typical day 2: 28 December 2018 (weekday)
- Flow-based typical day 3: 22 January 2019 (weekday)
- Flow-based typical day 4: 17 November 2018 (weekend)

As described in section 5.2.2.4, 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 three weekday domain sets is given in Figure 5.6.

Typical day 1 28/11/2018		FR load		
		low	medium	high
DE wind	low	0.25	0.50	0.20
	medium	0.70	0.14	0.08
	high	0.25	0.29	0.25

Typical day 2 28/12/2018		FR load		
		low	medium	high
DE wind	low	0.50	0.25	0.40
	medium	0.10	0.14	0.17
	high	0.00	0.00	0.00

Typical day 3 22/01/2019		FR load		
		low	medium	high
DE wind	low	0.25	0.25	0.40
	medium	0.20	0.71	0.75
	high	0.75	0.71	0.75

Figure 5.6

Each typical day consists of 24 hourly domains (one for each hour). A comparison of the domains of weekday typical days at 18h00 on two different planes is provided in Figure 5.7 and Figure 5.8. It can be seen the lower left quadrant of the BE-FR plane is impacted by the selection of the typical day. This boundary is highly relevant for the Belgium adequacy, as it constrains the combined import capacity available to France and Belgium from CWE.

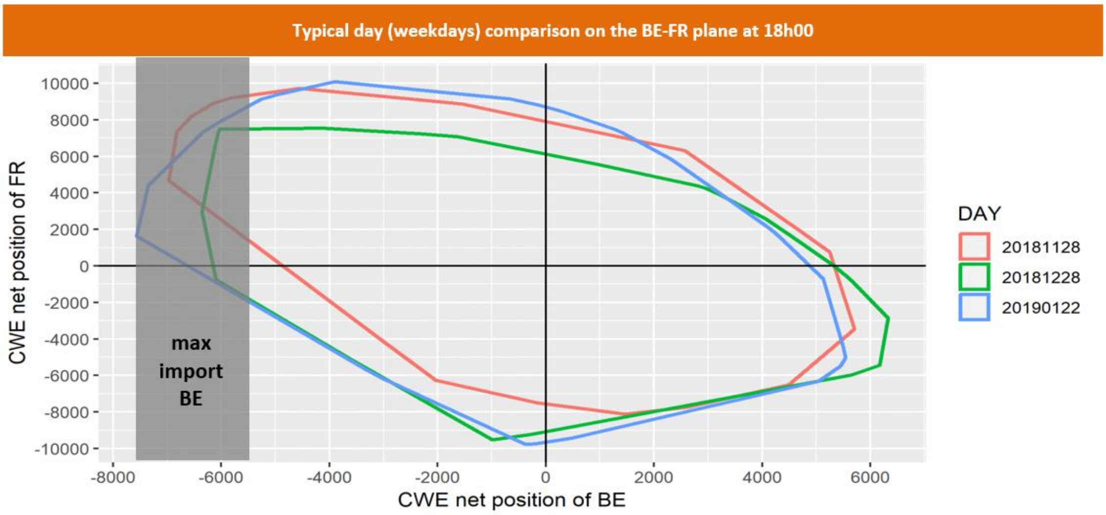


Figure 5.7

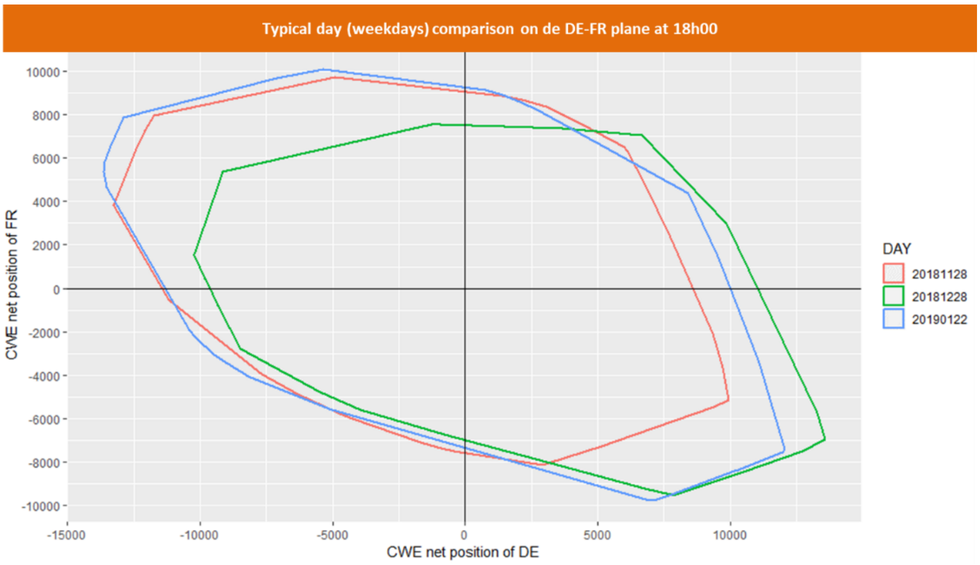


Figure 5.8

Understanding 2-dimensional flow-based domain representations

The flow-based domains used in this year's volume assessment are six-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 a lasso thrown around all points and then tightened is then calculated. All points which are not on the convex hull are omitted. Figure 5.9 shows a theoretical example of such a projection[23]. 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".

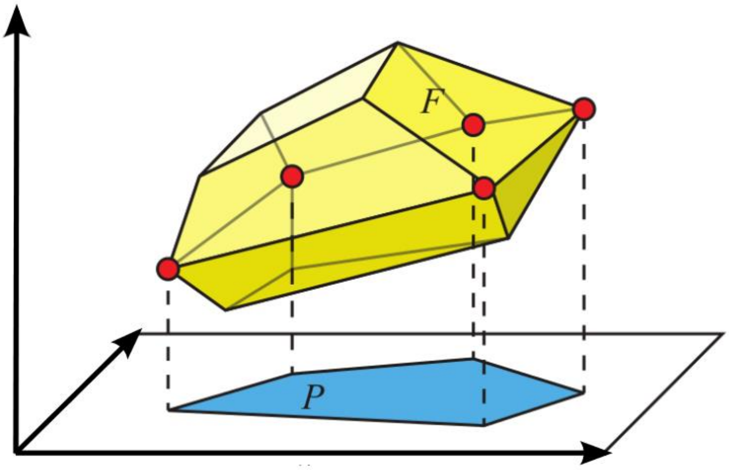


Figure 5.9

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 for this year's typical days at 18:00 is shown in Figure 5.10 where the impact of ALEGrO on the simultaneous Belgian-French import corner is also depicted.

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

All flow-based domain representations only depict CWE balances, as opposed to bidding zone balances. Hence, the import possibilities of CWE countries from outside CWE 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 CWE. 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 CWE 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 CWE 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®.

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

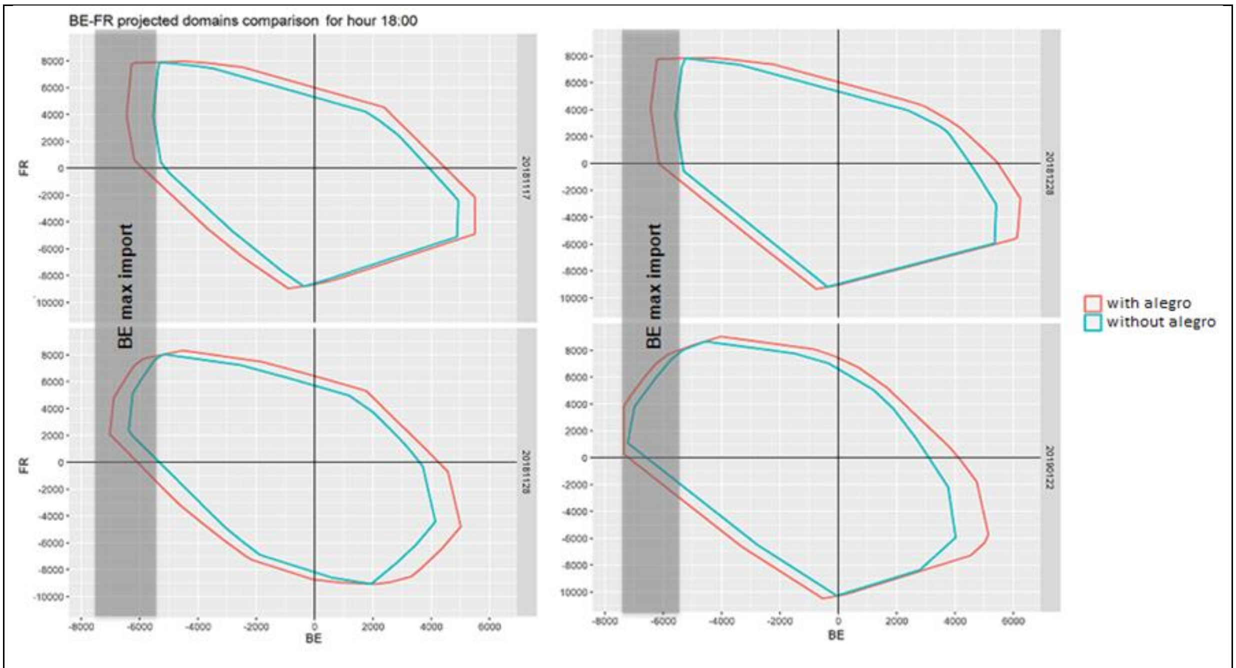


Figure 5.10

For the sake of completeness, an overview of all hourly domains for all typical days is provided below in Figure 5.11 to Figure 5.14.

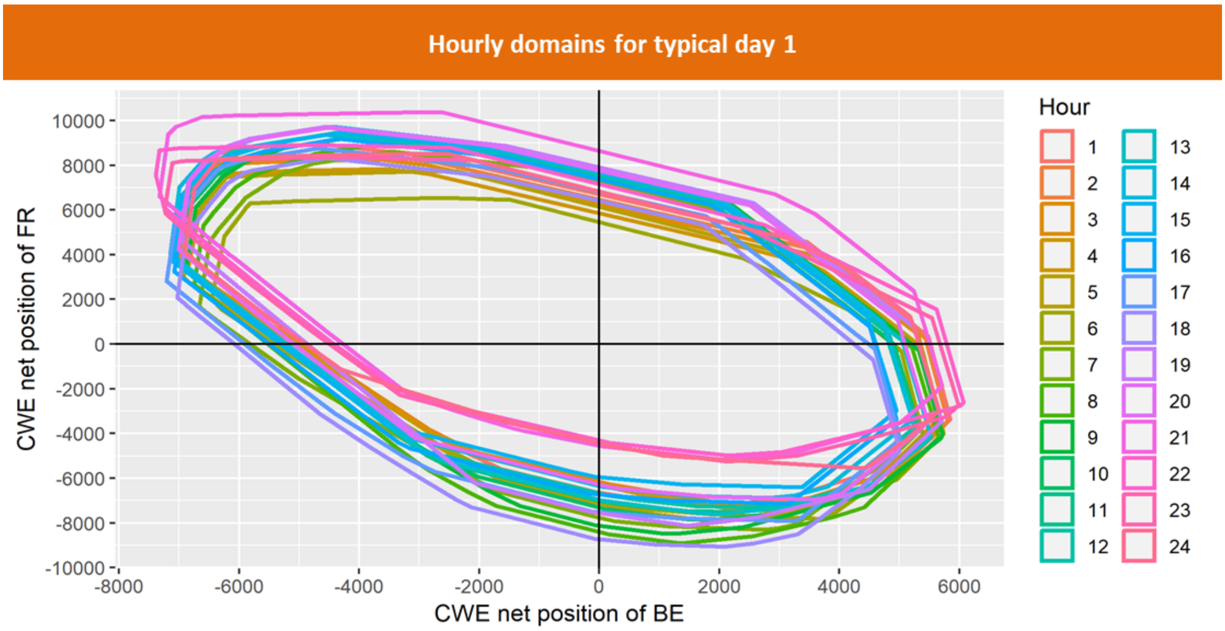


Figure 5.11

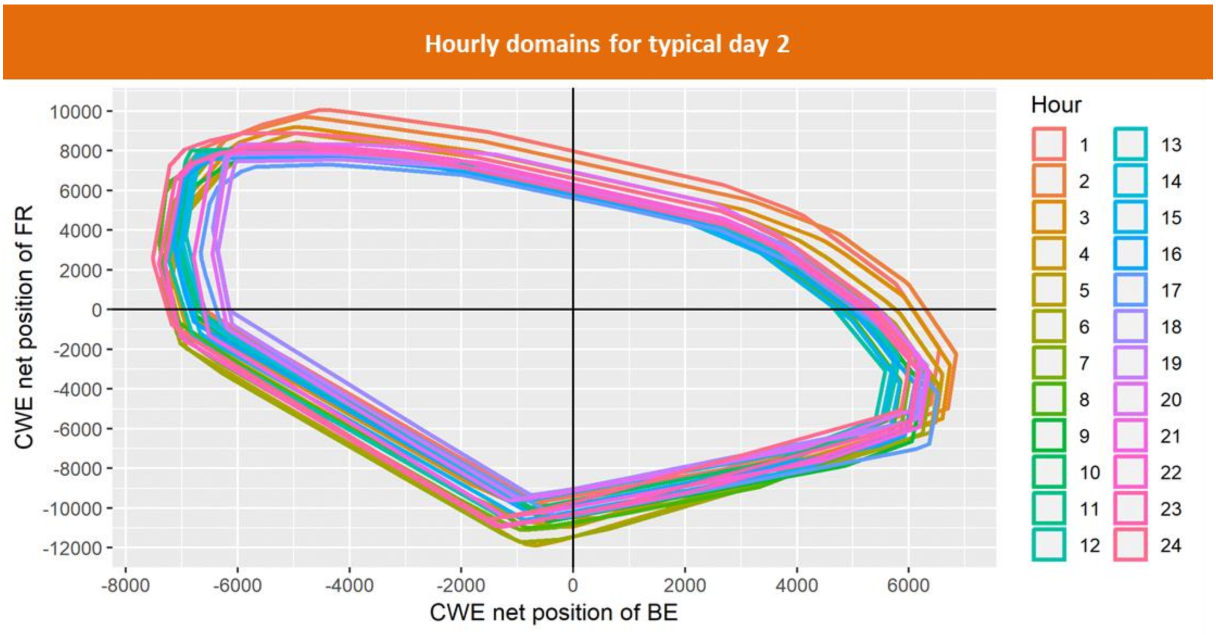


Figure 5.12

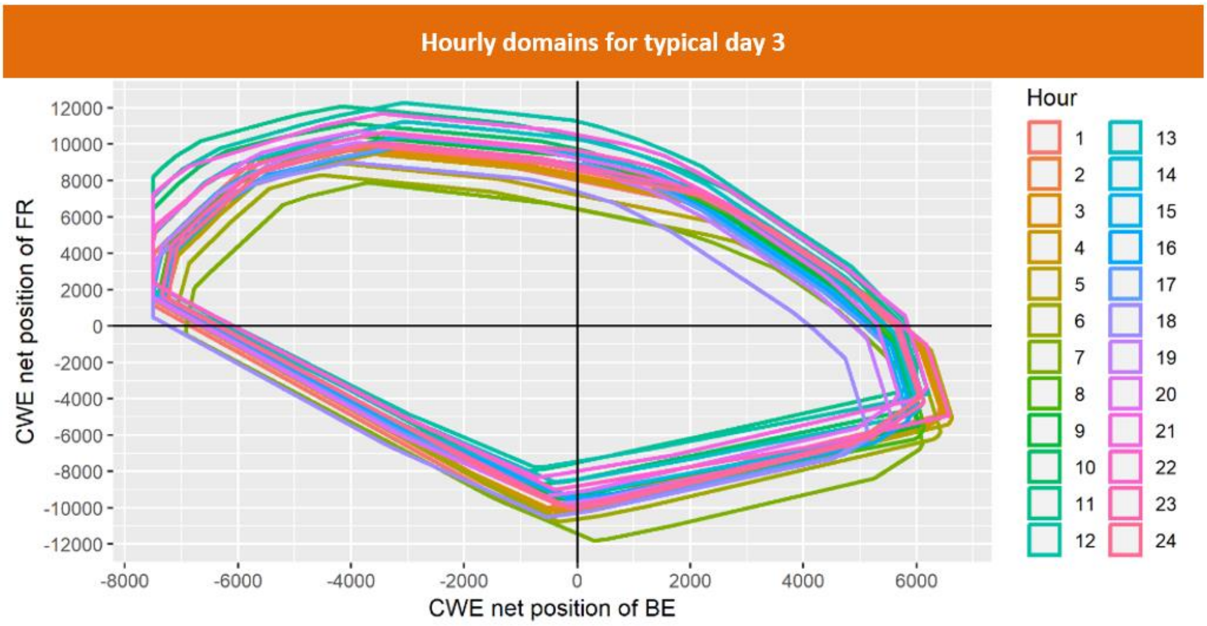


Figure 5.13

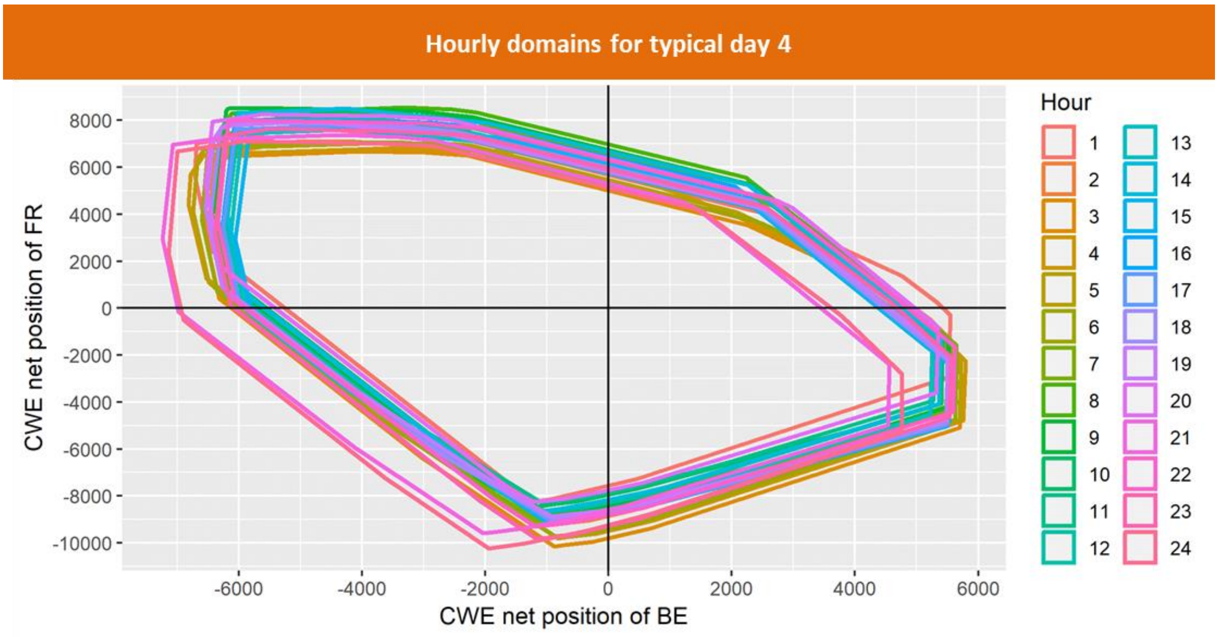


Figure 5.14

5.3 Exchange capacities on CWE 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 [24].

5.3.1 Import capacities of the CWE zone from neighbouring countries

The impact of countries outside the CWE zone on the risk of a structural shortage in Belgium consists of the capacity of these countries to provide energy to the CWE zone in case of a power shortage at CWE level.
The following import capacities (NTC) into the CWE zone are taken into account in this study:

— **Austria**: Total net import capacity for Austria from outside CWE is considered to be **3.9 GW** for winter **2020-21.** This value is the sum of import capacities on the borders with Czech Republic, Hungary, Switzerland, Italy, Slovenia;
— **Belgium**: Total net import capacity for Belgium from outside CWE is considered to be **1 GW** for winter **2020-21**, thanks to the HVDC interconnection with Great Britain (Nemo Link®);
— **Germany**: Total net import capacity for Germany from outside CWE is considered to be **10.4 GW** for winter **2020-21.** This value is the sum of import capacities on the borders with Poland, Czech Republic, Switzerland, Sweden, and Denmark. The first HVDC connection between Germany and Norway, NordLink, has been delayed to March 2021[60]. It introduces an additional 1400 MW of import capacity in Germany from winter 2021-22 onwards.
— **France**: Total net import capacity for France from outside CWE is considered to be **6.4 GW** for winter **2020-21**. This value is the sum of import capacities on the borders with Spain, Italy, Switzerland and Great Britain;

— **The Netherlands**: Total net import capacity for the Netherlands from outside CWE is considered to be **2.4 GW** for winter **2020-21.** This value is the sum of import capacities on the interconnectors with Norway and Great Britain as well as the 700 MW HVDC cable (COBRA cable [44]) between the Netherlands and Denmark.

The sum of import capacities shown in Figure 5.15 is the maximum possible import capacity on the outer CWE 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 CWE zone) at times of structural shortage. As the simulation scope includes those countries, the availability of generation is explicitly taken into account.

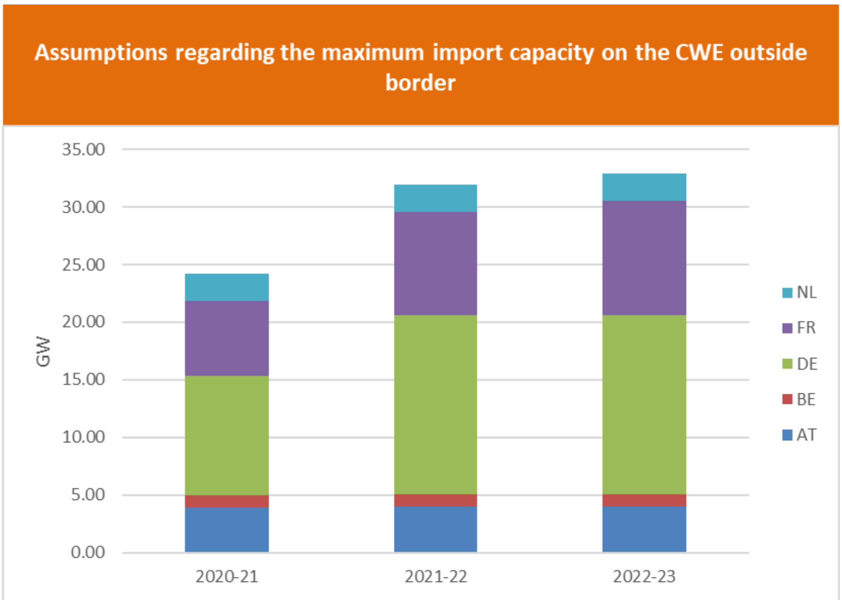


Figure 5.15

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 exist and could contribute to power supply of the CWE region. The countries that are modelled in addition to the CWE countries[24] are: Spain (ES), Portugal (PT), Great-Britain (GB), Ireland (IE), Northern Ireland (NI), Switzerland (CH), Slovenia (SI), Czech Republic (CZ), Slovakia (SK), Hungary (HU), Norway (NO), Denmark (DK), Sweden (SE) and Poland (PL). Since the geographical perimeter considered around Belgium is significant, the effect of the above mentioned assumption has little impact on the adequacy situation in Belgium.

5.3.2 HVDC forced outages

A detailed modelling of the availability of HVDC system elements is included in the analysis. The availability of HVDC interconnectors is modelled using a forced outage rate (FOR), which in this case defines the annual rate an HVDC interconnector is unavailable. Forced outages are simulated by random occurrences of outages within the probabilistic 'Monte Carlo' scheme (see section 8.1.1), whilst respecting the annual rate defined. This is illustrated in Figure 5.16 for the 1000 MW Nemo Link® HVDC interconnector between Belgium and Great Britain. The figure shows the average

[24] Germany (DE), France (FR), Belgium (BE), The Netherlands (NL), Luxembourg (LU) and Austria (AT)

availability of the interconnector throughout the winter, as well as some examples of availabilities for a given 'Monte Carlo' year. An unavailability rate for each HVDC interconnector of 6% has been used, in line with the value used for the ENTSO-E MAF report [16]. Moreover, the ENTSO-E 'HVDC Reliability' Task Force within the 'Asset Implementation and Management' Working Group (WG AIM) has confirmed the 6% HVDC FO as a benchmark value.

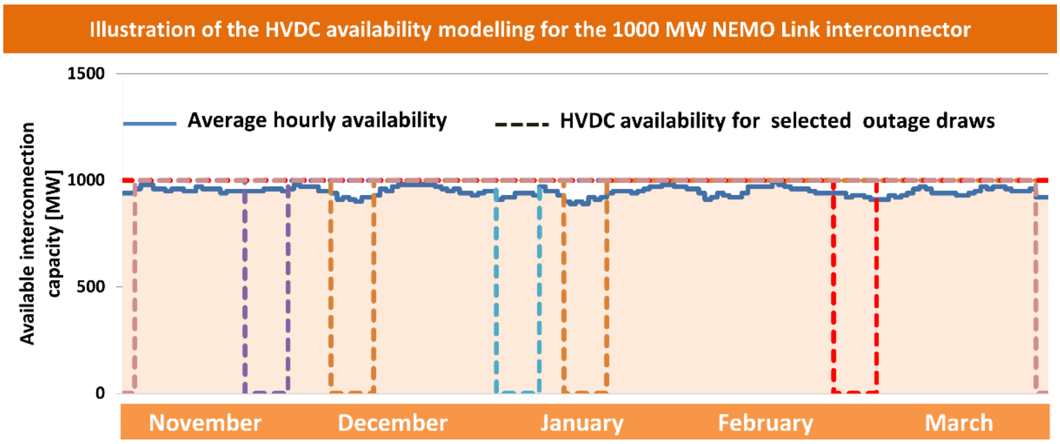
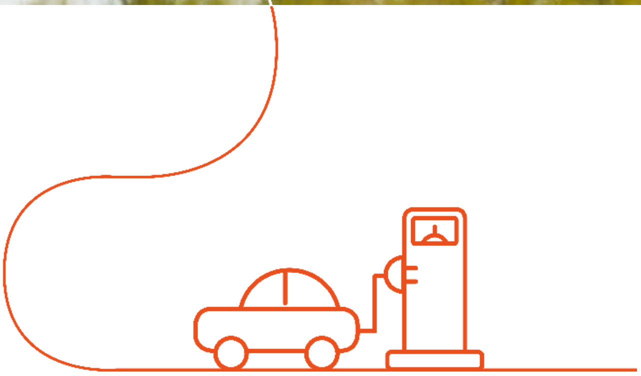


Figure 5.16

6. Results



This chapter contains the results for winter 2020-21, with an outlook for winter 2021-22 and winter 2022-23. Section 6.1 provides a short overview of the main assumptions used for winter 2020-21. Section 6.2 provides a detailed analysis of the results for the 'base case' scenario for winter 2020-21. In addition to the 'base case' scenario, a sensitivity regarding nuclear availability in Belgium and France was also analysed for winter 2020-21. This 'High Impact, Low Probability' scenario, together with its results is discussed in section 6.3. Section 6.4 presents the corresponding results for winter 2021-22 and winter 2022-23.

The results 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. Additionally a table is given next to the chart containing P50 and maximum values of LOLE;
- 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 Assumptions for winter 2020-21

6.1.1 Main assumptions for Belgium

The 'base case' was constructed on the basis of the situation as known at the end of October 2019. A brief summary of this 'base case' scenario is given below, with the details provided in chapters 3, 4 and 5:

- Thermal generation facilities are taken into account as known at the end of October 2019, based on the latest closure announcements by generators (announced at the latest by 31 July 2019 for winter 2020-21) (see chapter 0).
- Regarding their availability, an extract of the transparency channels (REMIT) taken on 15 October 2019, is used for the purposes of this study.
- In this extract, some planned unavailabilities still remained for winter 2020-21. Below is an exhaustive overview of those unavailabilities, which have been taken into account for the entire analysis performed:
  - DOEL 2: maintenance from 27/2/2021 to 9/4/2021 (inclusive)
  - TIHANGE 2: maintenance from 7/11/2020 to 18/12/2020 (inclusive)

— Market response is taken into account based on the results of the market response study (845 MW for winter 2020-21).
— Forecast installed capacities for onshore wind and PV are a best estimate based on a consultation with the regions. Offshore installed capacity is forecast on the basis of a best estimate by Elia and FPS Economy.
— Total demand growth is approximately 0.5%/year on average between the years 2020 and 2023.
— Forced outage rates are based on observations over the past 11 years, excluding the exceptional nuclear unavailability experienced in Belgium in recent years, which is specifically covered by the analysed sensitivity.

6.1.2 Main assumptions for other countries

French assumptions are in line with the MAF 2019 and with latest assumptions;
Dutch assumptions are in line with the latest TenneT adequacy report 2019 (to be published by the end of the year);
German assumptions are in line with the latest communications from German regulator BNetzA [30];
Assumptions for **Great Britain** follow the data collection process for 2019 MAF. Those assumptions in turn follow the 'Steady Progression' scenario from the 'Future Energy Scenarios' (FES) produced by National Grid in July 2018 [22].

6.1.3 Interconnections

The HVDC interconnector between Belgium and Great Britain (Nemo Link®) capable of exchanging 1000 MW is assumed to be available.
Flow-based modelling with four typical days for winter 2020-21 is used in this assessment for the CWE region, taking into account the DE-AT split. For the rest of Europe, interconnection capacity is modelled as NTC.
A maximum simultaneous import capacity of 6500 MW is considered for Belgium in winter 2020-21. This simultaneous import capacity is imposed on the 'global Belgian import', i.e. import from CWE plus the flow through Nemo Link®.
As mentioned in section 5.2.1, the 'base case' scenario considers the effect of a 20% minimum remaining available margin (minRAM20%) for the day-ahead flow-based market coupling (FBMC) domains considered.

6.2 Results for winter 2020-21 'base case'

6.2.1 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 2020-21 is **below 30 minutes** and the percentile 95 is **1 hour**. These results are below the criteria defined by law, and the margin corresponding to the 2020-21 'base case' scenario is **3200 MW**. **There is thus no need for strategic reserves in the 'base case' scenario.**

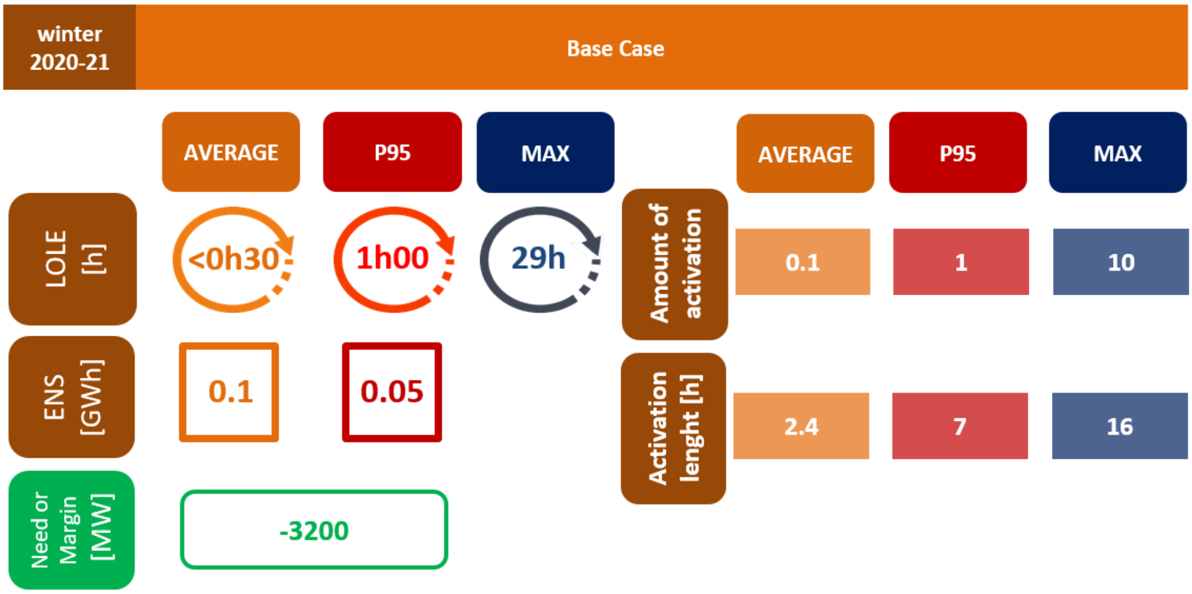


Figure 6.1

As can also be observed in Figure 6.1, the number of activations of a possible volume of strategic reserve would be very low: **0.1 times** per year on average, **1 time** in P95 and **10 times** in the most extreme 'Monte Carlo' year 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 **16 hours** without interruption. The average of the activation length is around **2.4 hours**.

Figure 6.2 shows the cumulative distribution of the LOLE over all 'Monte Carlo' years simulated for the 'base case' scenario when no volume or margin was added. The probability of having at least one hour of structural shortage amounts to **7%** for winter 2020-21. In the most extreme year simulated, **29 hours** of structural shortage were obtained. However, this is very rare, as shown by the P95 which is limited to **1 hour**. As a consequence, in the 'base case' scenario for winter 2020-21, the P10 & P50 indicators are all equal to **0 hours**.

Furthermore, Figure 6.1 and Figure 6.3 show that the amount of Energy Not Served (ENS) is limited to a value lower than **0.1 GWh** over the winter on average and to **0.5 GWh** in P95. A very steep tail section makes it possible to have a P95 lower than the average value.

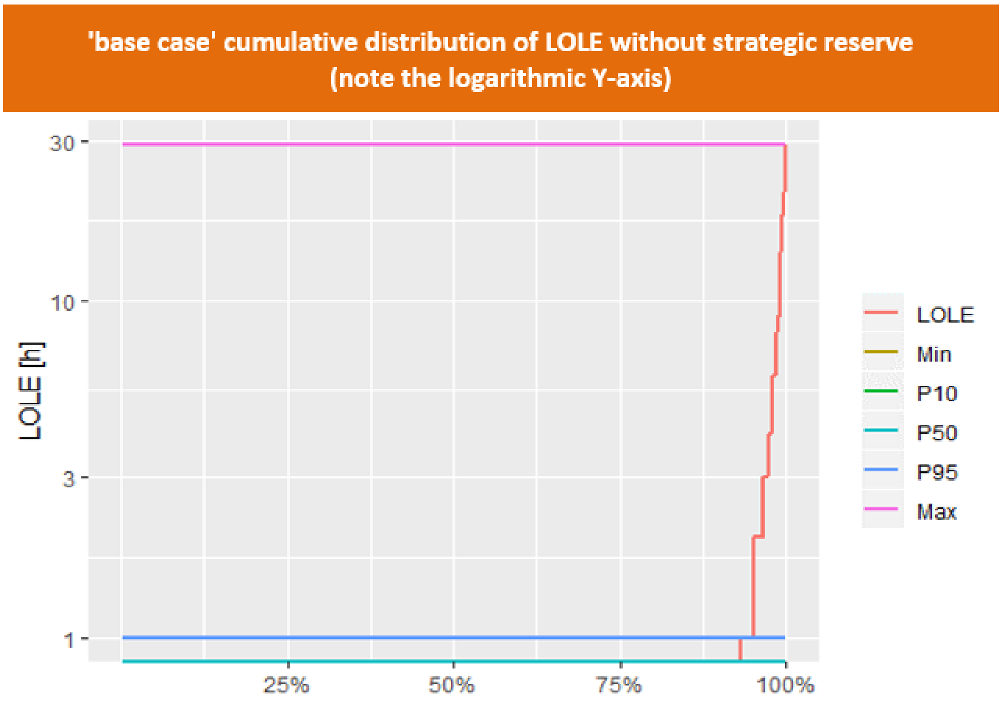


Figure 6.2

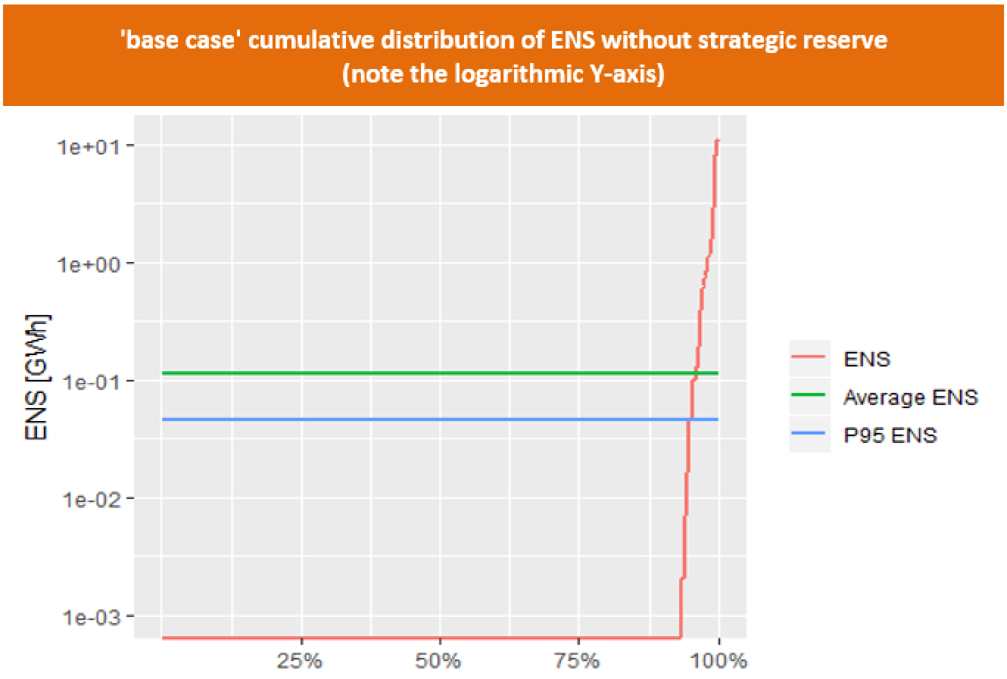


Figure 6.3

6.2.2 Imports in periods of structural shortage

The hours in which structural shortage is identified for winter 2020-21 in the 'base case' simulation, can be classified on the basis of Belgium's imports during these hours (see Figure 6.4).

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 CWE (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.

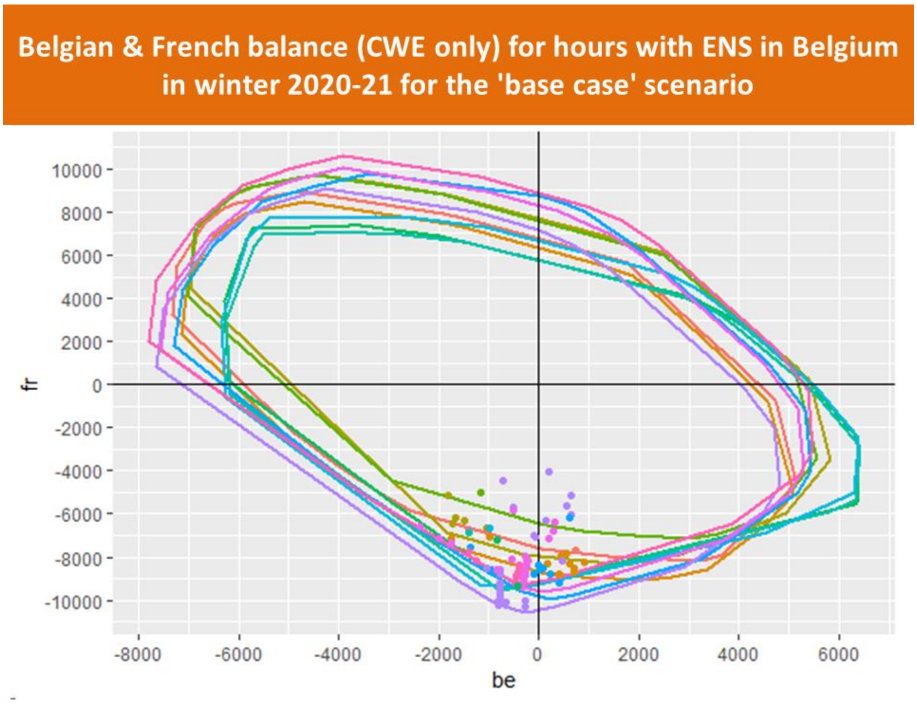


Figure 6.4

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 6.14 later on.

Figure 6.5 depicts the distribution of ENS among the different flow-based domains for the winter 2020-21 'base case', both per hour and aggregated per 'typical day'. The hours with highest contribution to ENS are 'hour 18' (17:00 - 18:00 UTC) and 'hour 19' (18:00 - 19:00 UTC[25]) for the domains from typical day 20190122.

Furthermore, from the hourly distribution of ENS amongst the Flow-Based domains depicted in Figure 6.5, it can be seen that ENS can also occur at hours other than the evening peak-load hours. ENS is observed from 7 AM CET when the electricity demand starts to increase before the morning peak.

[25] In this year's analysis, as a direct consequence of an alignment effort within ENTSO-E, coordinated universal time (UTC) is used in all models. The UTC time standard relates to the central European timezone (CET) which is used in Belgium in winter as follows: CET = UTC + 1.

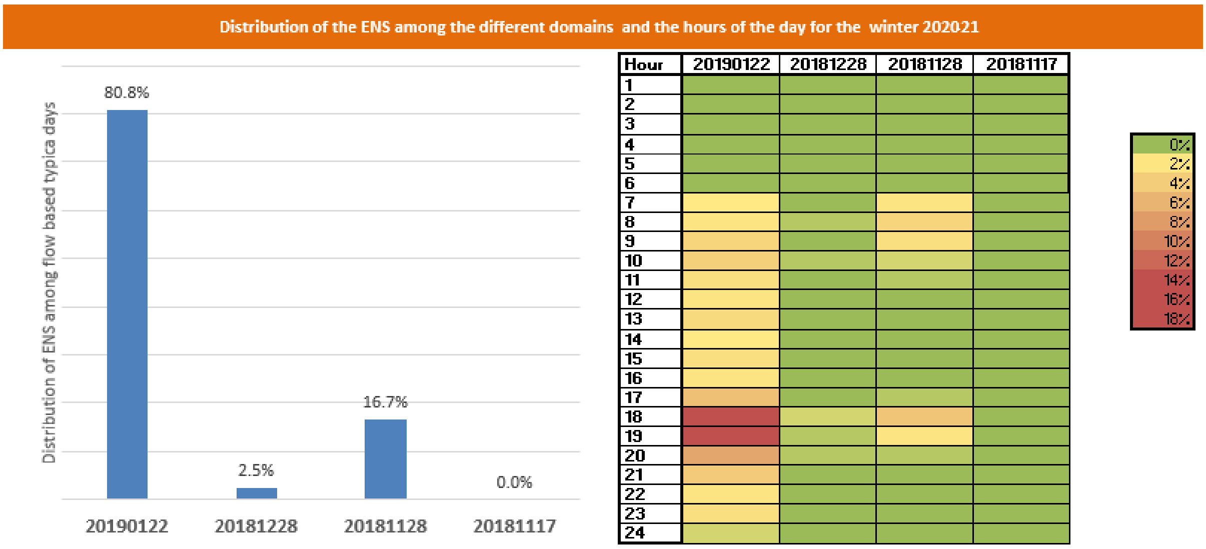


Figure 6.5

6.2.3 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 2020-21, amounting to 840 MW, is taken into account with constraints on the number of activations and their duration, as described in section 3.3.

Figure 6.6 (left) shows three days of the simulation during which a relatively small structural shortage occurs. In such situations, market response helps to cover the shortages. It can be seen that market response makes it possible to cover Energy Not Served, resulting in no structural shortage during three consecutive 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. However, later in that week there are still remaining hours that cannot be covered due to the imposed limitations on the activations of such volume taken into account in this study.

Figure 6.6 (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.

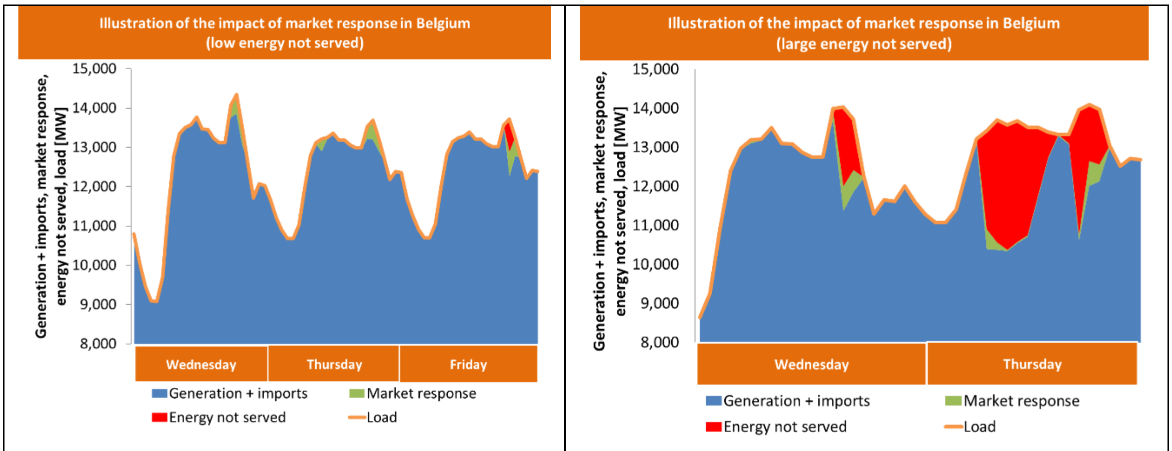


Figure 6.6

6.2.4 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 CWE and via Nemo Link® and is shown in Figure 6.7. 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.

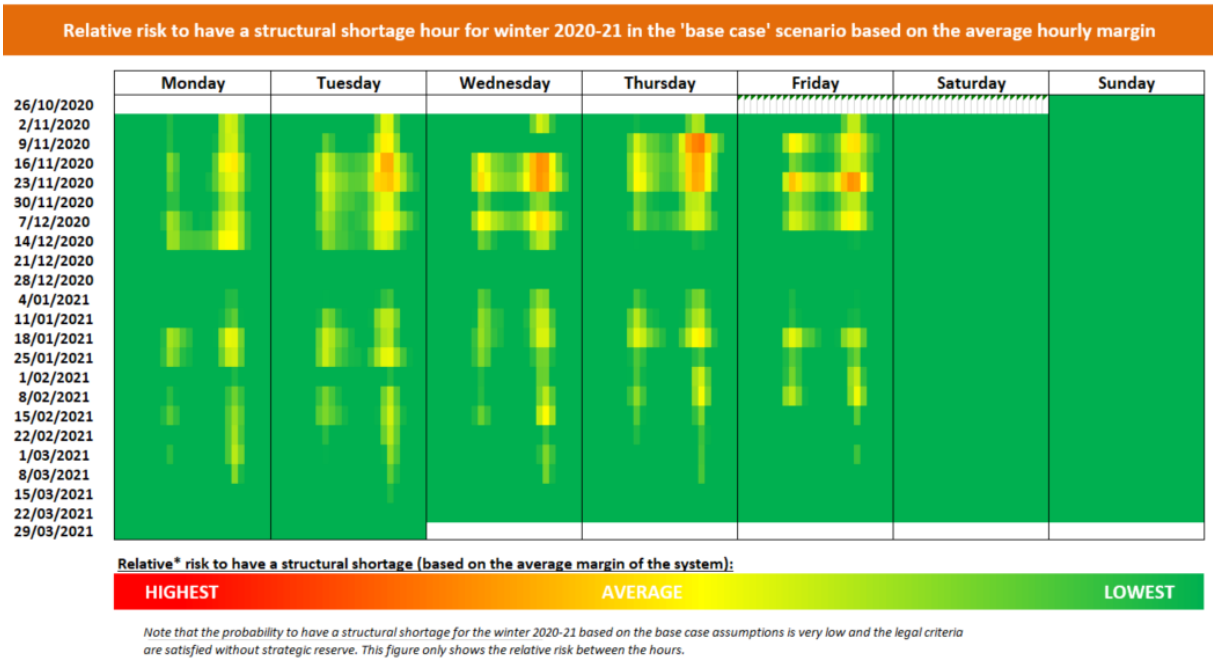


Figure 6.7

6.3 Results for winter 2020-21 'High Impact, Low Probability' scenario

To offer guarantees in terms of the country's security of electricity supply, the 'High Impact, Low Probability' scenario is particularly relevant since it provides protection against events over which the Belgian State has no control or influence. It is this scenario on which previous decisions for the contractualisation of the strategic reserves were based by the public authorities. Indeed, the use of such a scenario, was considered appropriate by the European Commission's DG Competition via its decision SA.48648 validating the strategic reserve mechanism. Section 6.3.1 provides more details about this sensitivity, together with the elements that justify the analysis of the sensitivity. In section 6.3.2 the results of the sensitivity analysis are given.

6.3.1 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, has been seen 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), a detailed comparison between the availability modelled in the 'base case' and the Belgian nuclear availability experienced in recent winters was conducted. This exercise was updated with the latest historical data. Two conclusions can be drawn from the result as shown in Figure 6.8. Firstly, by analysing the average and P95 of historical nuclear availability it becomes apparent that the 'base case'-modelled availability is highly optimistic in terms of both indicators. Secondly, the difference between the model's average and P95 availability is less than in last years' analysis, due to the fact that the planned outages of nuclear generation for winter 2020-21 are not simultaneous. This increases the P95 availability. As a direct result, the removal of 2 GW of nuclear generation is required to align the P95 availability in the model with the one in the historical data. However, this then leads to a very large gap between modelled and average historical availability. A compromise for both indicators is found when reducing the available nuclear capacity in the base case scenario by 1.5 GW.

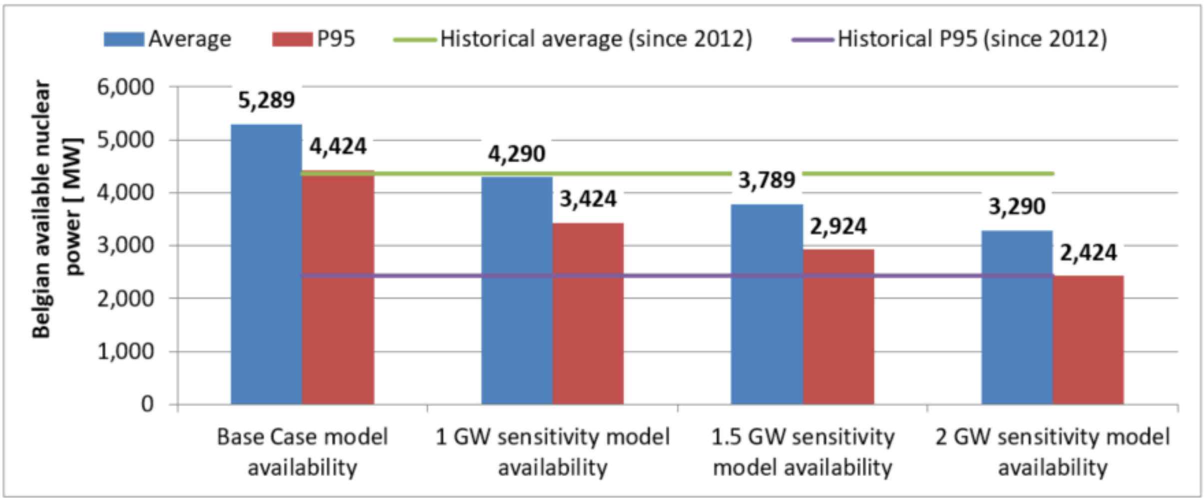


Figure 6.8

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 same analysis was conducted for **French nuclear availability**. When comparing the French P95 nuclear availability modelled in the 'base case' with the historical French nuclear availability of the last 7 winters, it is shown that a **sensitivity with an additional 3.6 GW (4 units of 910 MW) of nuclear production capacity out of service** for the entire winter in France should be considered in order to bring the P95 modelled availabilities in line with the experienced availabilities over the last 7 winters in France.

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.

6.3.2 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 for both legally required criteria (LOLE average and LOLE95). The resulting values are shown in Figure 6.9 for the sensitivity. The LOLE average for winter 2020-21 in this sensitivity is **2 hour and 45 minutes** and the percentile 95 LOLE is **11 hours**. These results are lower than the criteria defined by law, and the margin corresponding to the 2020-21 'high-impact low-probability' scenario is **100 MW. There is thus no need for strategic reserves in the 'High Impact, Low Probability'-scenario.**

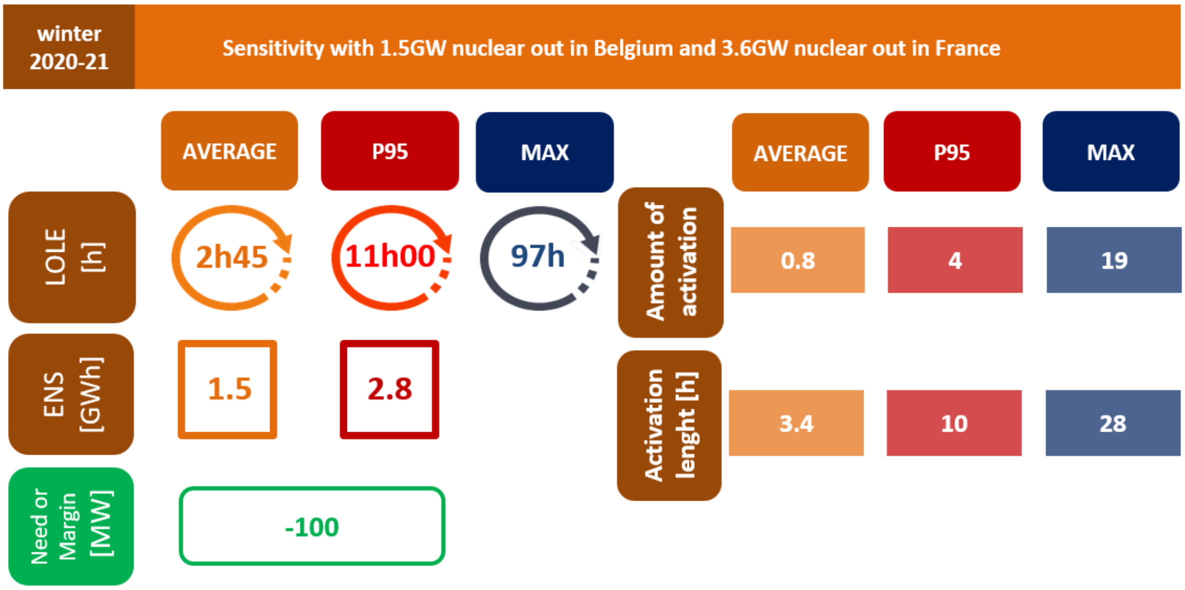


Figure 6.9

As can also be observed in Figure 6.9, the number of activations of a possible volume of strategic reserve would be low: **0.8 times** per year on average, **4 times** in P95 and **19 times** in the most extreme 'Monte Carlo' year 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 **28 hours** without interruption. The average of the activation length is around **3.4 hours**.

Figure 6.10 shows the cumulative distribution of the LOLE over all 'Monte Carlo' years simulated for the 'High Impact, Low Probability' scenario when no volume or margin was added. The probability of having at least one hour of structural shortage amounts to **20%** for winter 2020-21 in this sensitivity. In the most extreme year simulated, **97 hours** of structural shortage were obtained. However, this is very rare, as shown by the P95 which is limited to **11 hours**.

Furthermore, Figure 6.9 and Figure 6.11 show that the amount of energy not served (ENS) is limited to **1.5 GWh** over the winter on average and to **2.8 GWh** in P95.

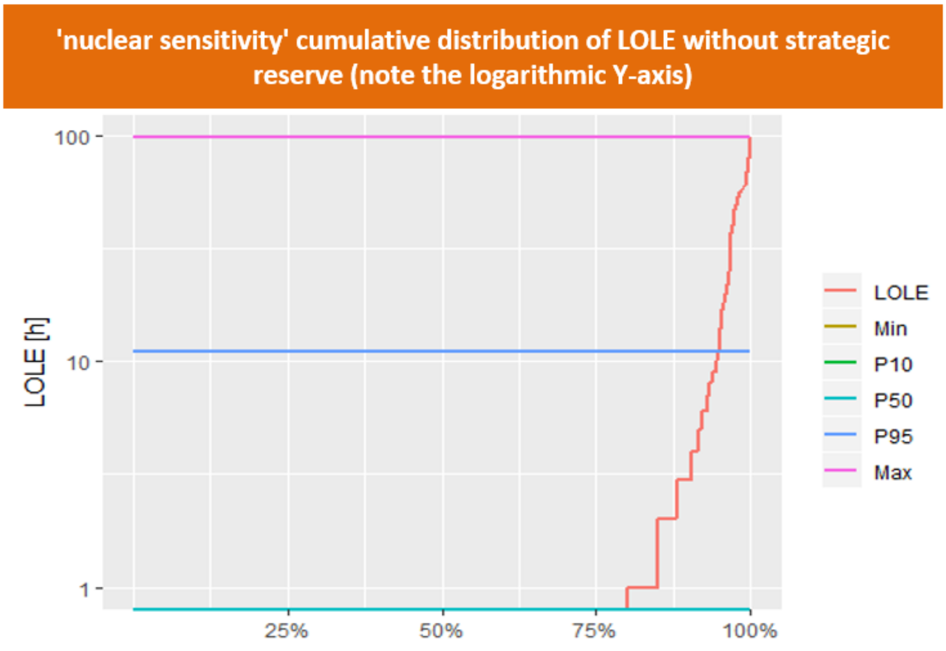


Figure 6.10

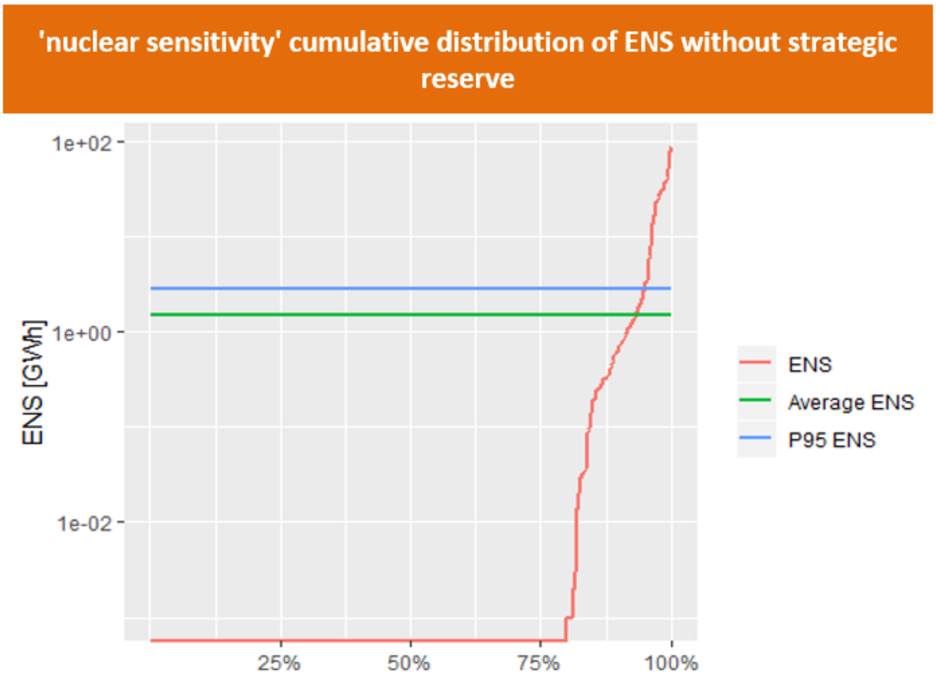


Figure 6.11

6.3.3 Imports in periods of structural shortage

As for the 'base case' simulation, Belgium's and France's imports within CWE, during hours of ENS, are shown also here for the 'High Impact, Low Probability' scenario (see Figure 6.12).

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 CWE (resulting from flow-based market coupling). The dots relate to the flow-based domains of the same colour.

Depicted Belgian imports within CWE are lower than the maximum import. The constraint on maximum simultaneous import capacity therefore has no impact on Belgian adequacy.

Figure 6.13 shows two types of scarcity situations for Belgium. In the left panel situations with both Belgium & France in scarcity are shown. In the right, situations with both Belgium, France & Great-Britain in scarcity are found. These three cases add up to 96% of all scarcity situations.

Additionally, as can be seen in Figure 6.14, Belgium is never alone after the application of the patch. This shows that scarcity in Belgium is driven by available energy abroad, rather than by the availability of interconnection capacity. Indeed, in times of scarcity in Belgium, other CWE countries are also depending on imports to cover their domestic demand. Due to flow factor competition, these countries might be assigned a larger share of the available energy. However, curtailment sharing principles of the adequacy patch will socialize the total unsupplied energy between all countries that are at that time depending on imports to cover domestic load.

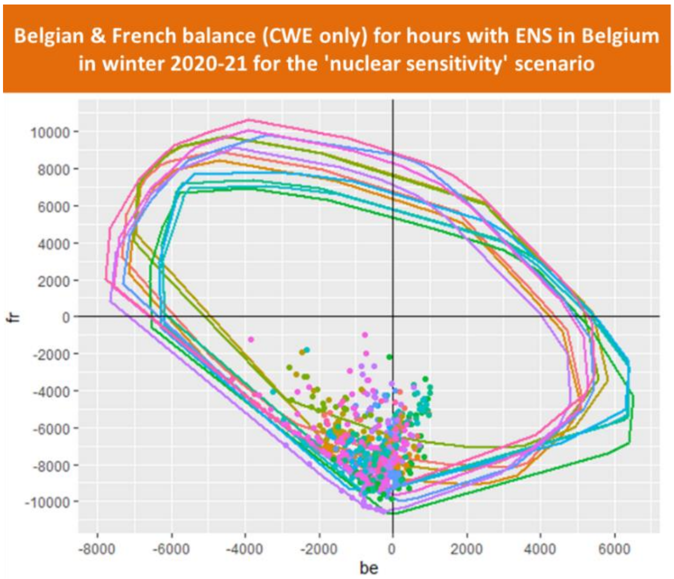


Figure 6.12

Belgian & French balance (CWE only) for hours in deficit in Belgium in winter 2020-21 for the 'nuclear sensitivity' scenario. Comparison of different curtailment sharing situations.

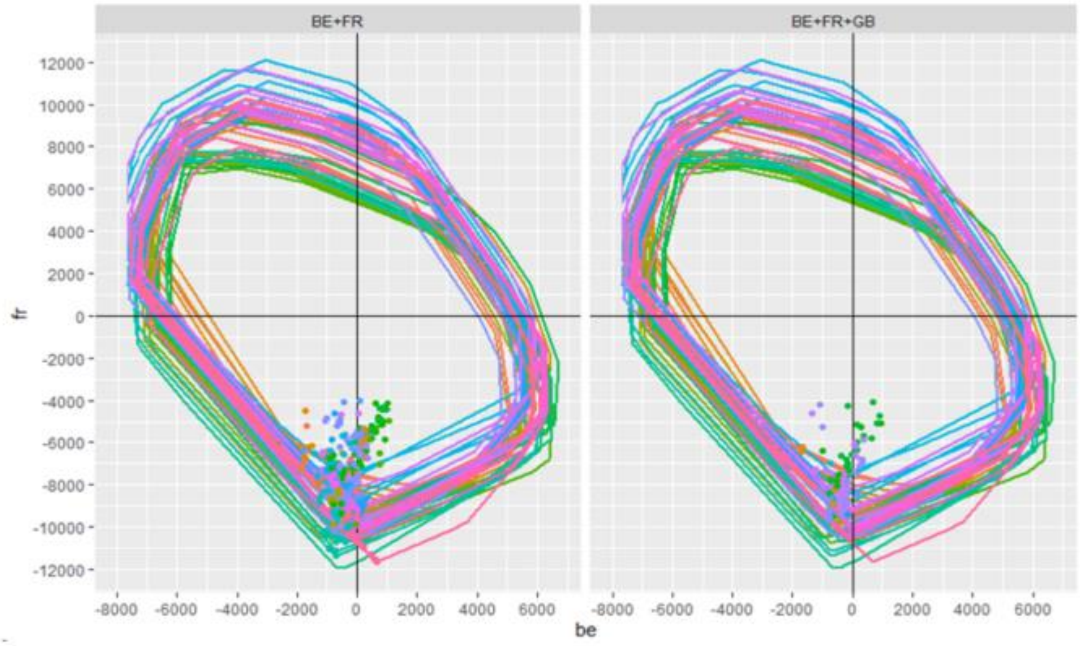


Figure 6.13

Curtailment sharing distribution in Belgium in winter 2020-21 for the 'nuclear sensitivity' scenario

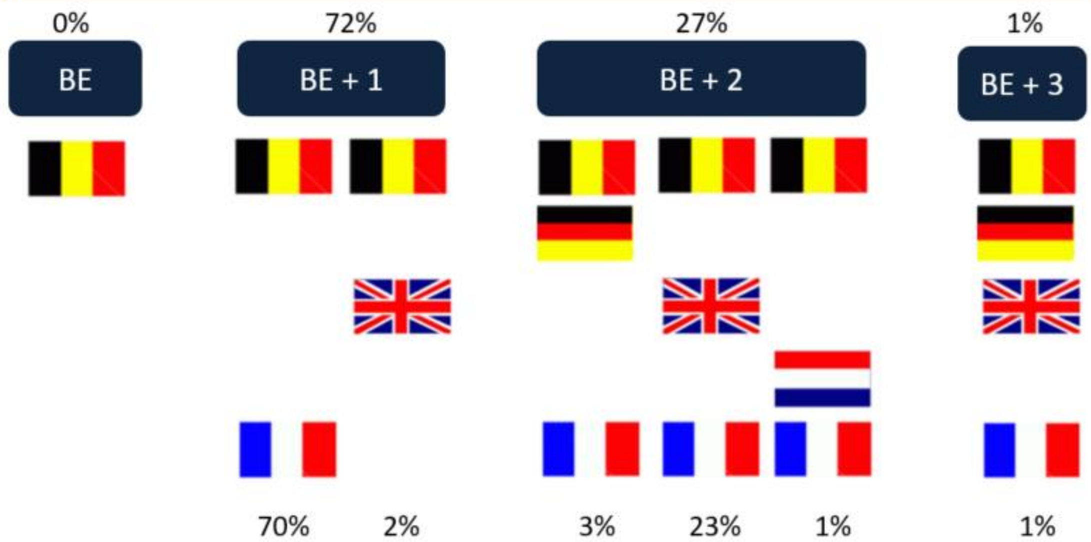


Figure 6.14

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

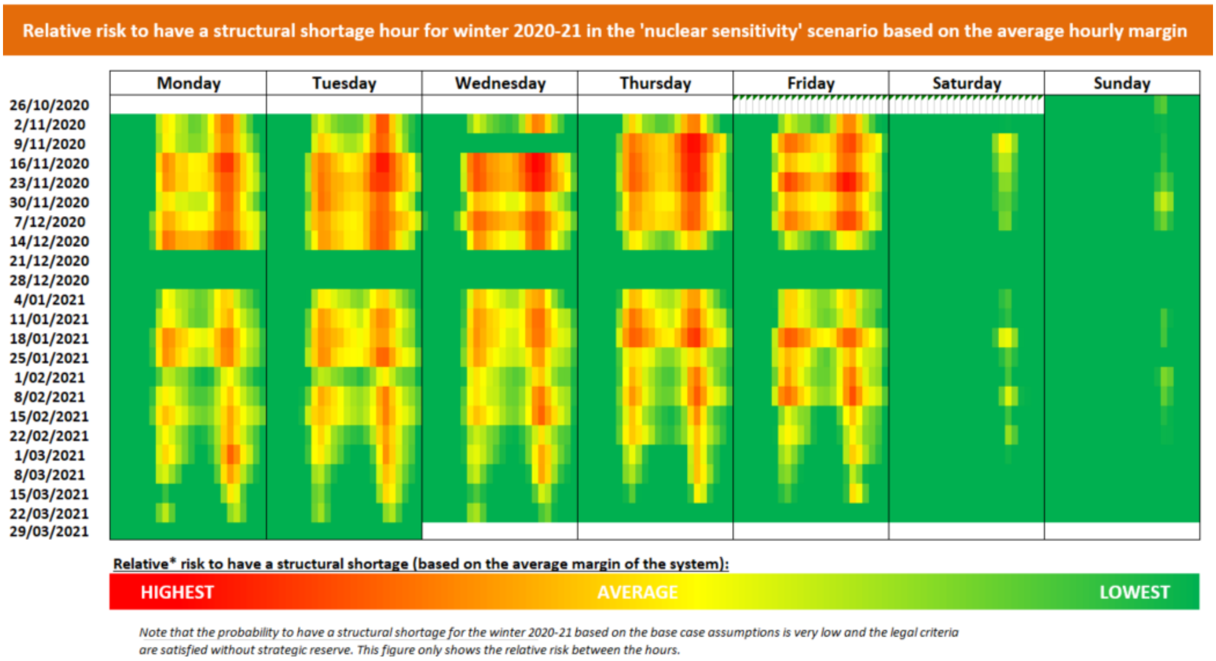


Figure 6.15

The risk of structural shortage for the 'high-impact low-probability' case has been calculated from the hourly remaining margin of the system, after taking into account all possible imports within CWE and via Nemo Link® (see Figure 6.15). 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.

6.4 Results for winter 2021-22 'base case'

6.4.1 Changes in Belgian assumptions

The 'base case' for winter 2021-22 follows the assumptions presented in chapter 3. The main changes of winter 2021-22 compared to winter 2020-21 are:

- Regarding the planned unavailabilities of the thermal park, the REMIT publication of planned outages during winter 21-22 is used as a reference. REMIT was monitored until 15 October 2019. For winter 2021-22, some planned unavailabilities are listed. Below, an exhaustive overview of those unavailabilities, which have been taken into account for all the analysis performed, is provided:
  - ➢ TIHANGE 1N: maintenance from 05/02/2022 until 08/03/2022 (inclusive)
  - ➢ TIHANGE 1S: maintenance from 05/02/2022 until 08/03/2022 (inclusive)
  - ➢ TIHANGE 3: maintenance from 21/02/2022 until 31/03/2022 (inclusive)

- ➢ DOEL 2: maintenance from 19/02/2022 until 01/04/2022 (inclusive)
- ➢ DOEL 4: maintenance from 23/10/2021 until 30/11/2021 (inclusive)

— Market response is taken into account in line with the results of the market response study and a progressive stance on growth rate (924 MW for winter 2021-22);
— An increase in domestic renewable energy generation;
— Total demand growth is approximately 0.4%/year on average between the years 2020 and 2023.

6.4.2 Calculation of LOLE, ENS and number of activations

The resulting values are shown in Figure 6.16. The LOLE average for winter 2021-22 in the 'base case' is **below 30 minutes** and the percentile 95 is **2 hours**. These results are lower than the criteria defined by law, and the margin corresponding to the 2021-22 'base case' scenario is **2800 MW.**

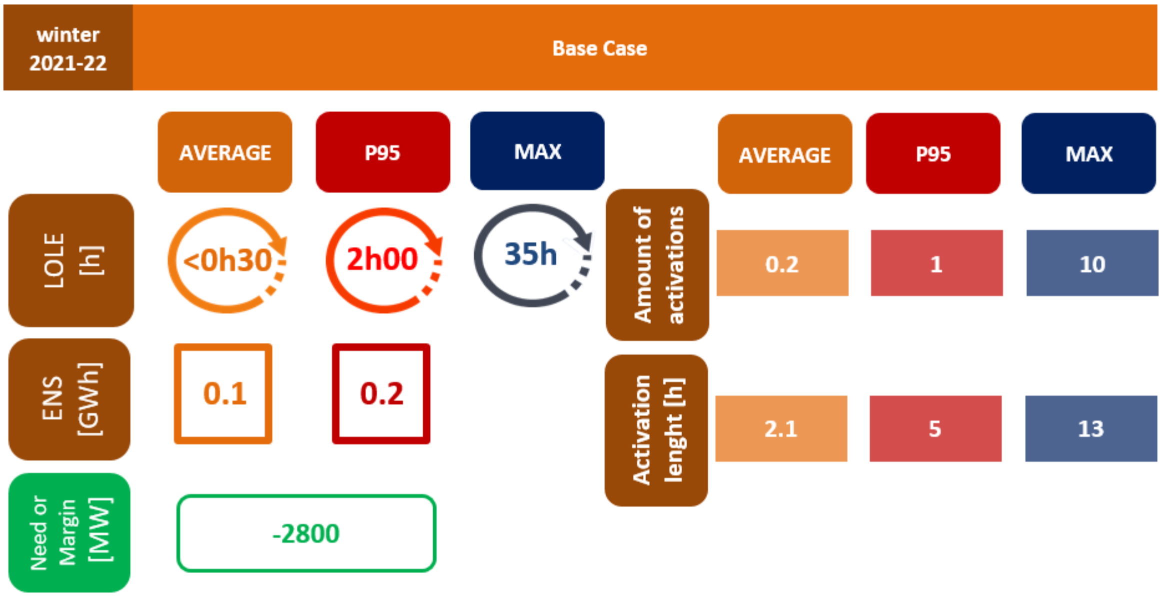


Figure 6.16

It can also be observed in Figure 6.16 that the number of activations of a possible volume of strategic reserve would be very low: **0.2 times** per year on average, **1 time** in P95 and 10 times in the most extreme 'Monte Carlo' year simulated. The figure also indicates the maximum duration for which 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 **13 hours** without interruption. The average of the activation length is around **2.1 hours**.

Figure 6.17 shows the cumulative distribution of the LOLE over all 'Monte Carlo' years simulated for the 'base case' scenario when no volume or margin was added. The probability of having at least one hour of structural shortage amounts to **9%** for winter 2021-22. In the most extreme year simulated, **35 hours** of structural shortage were obtained. In the 'base case' scenario for winter 2021-22, P10 and P50 are equal to **0 hours** and P95 is **2 hours**.

Furthermore, Figure 6.16 and Figure 6.18 show that the amount of Energy Not Served (ENS) is **0.1 GWh** over the winter on average and lower than **0.2 GWh** in P95.

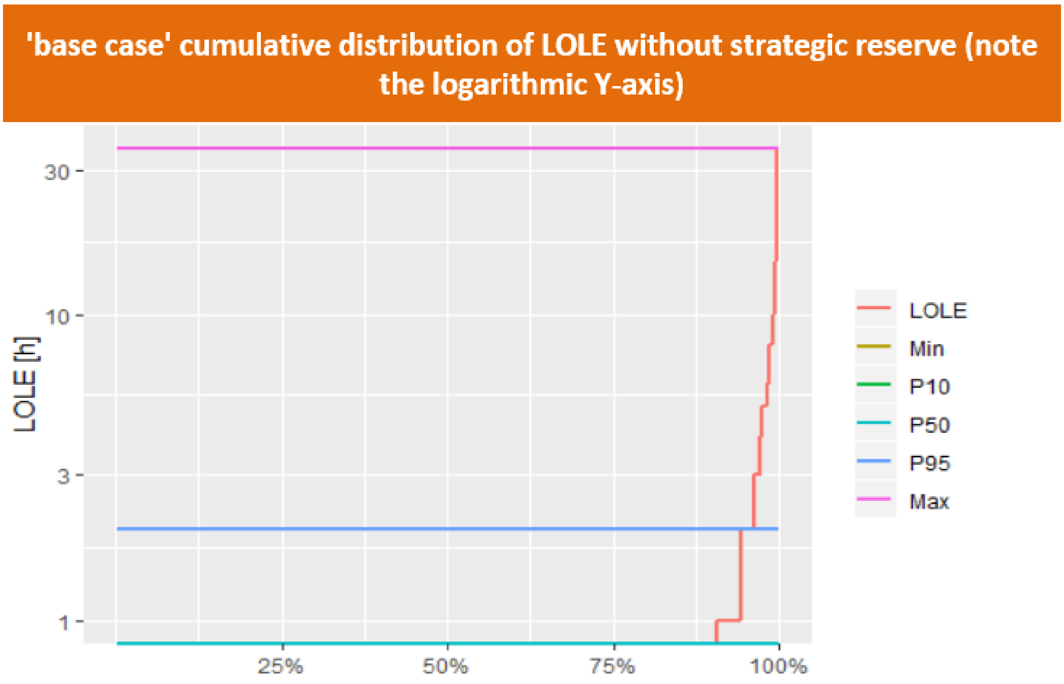


Figure 6.17

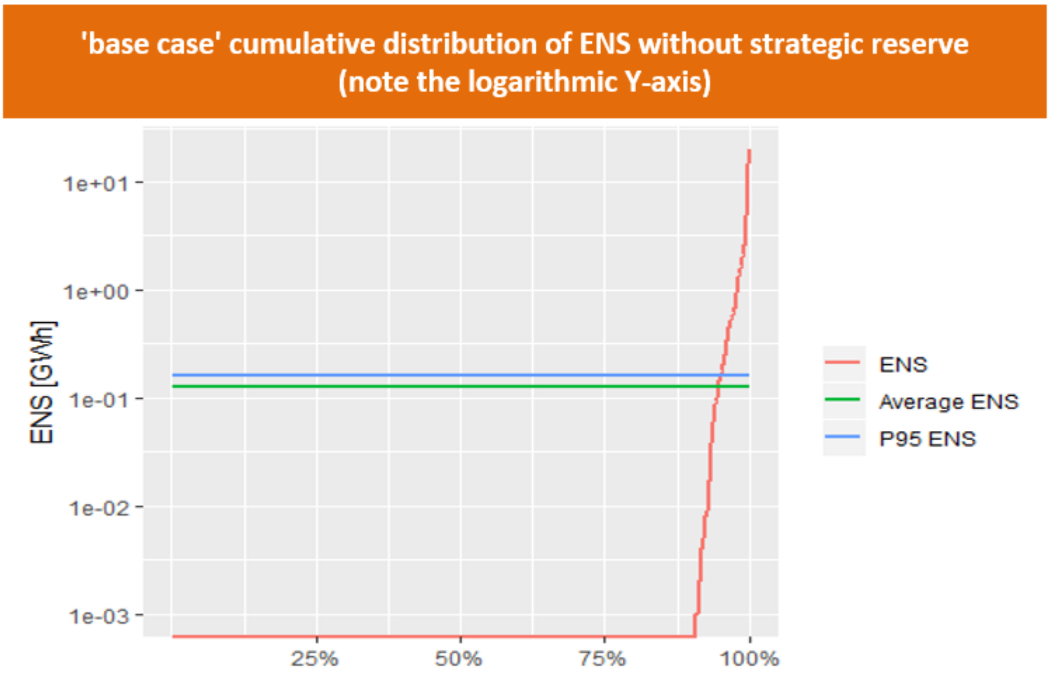


Figure 6.18

6.5 Results for winter 2021-22 'High Impact, Low Probability' sensitivity

6.5.1 Description of the nuclear sensitivity

The same sensitivity as defined for winter 2020-21 (described in section 6.3.1) is analyzed in winter 2021-22. This approach is chosen since it is considered that the unusual outages that occurred for Belgian and French nuclear power plants between 2014 and 2018 should be representative enough of low probability events having a big impact on Belgium's adequacy.

6.5.2 Calculation of LOLE, ENS and number of activations

The resulting values are shown in Figure 6.19 for the sensitivity. The LOLE average for winter 2021-22 in this sensitivity is **2 hours 30 minutes** and the percentile 95 is **12 hours**. These results are lower than the criteria defined by law, and the margin corresponding to the 2021-22 'high-impact low-probability' scenario is **200 MW.**

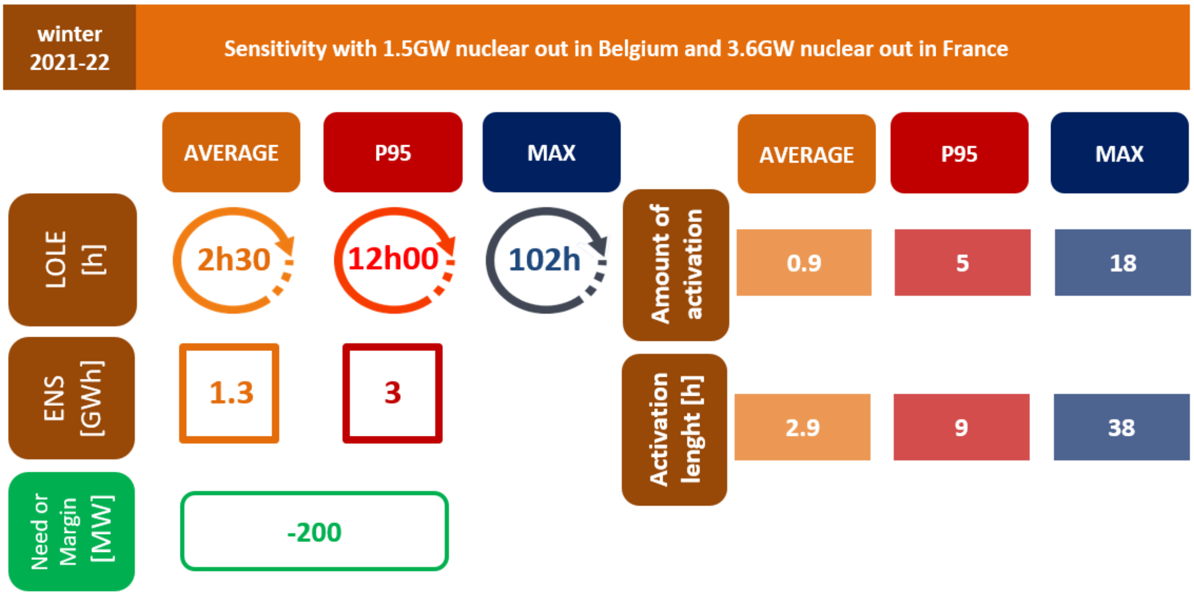


Figure 6.19

It can also be observed in Figure 6.19 that the number of activations of a possible volume of strategic reserve would be low: **0.9 times** per year on average, **5 times** in P95 and **18 times** in the most extreme 'Monte Carlo' year 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 **38 hours** without interruption. The average of the maximal activation length is around **2.9 hours**. Figure 6.20 shows the cumulative distribution of the LOLE over all 'Monte Carlo' years simulated for the 'High Impact, Low Probability' scenario when no volume or margin was added. The probability of having at least one hour of structural shortage amounts to **23%** for winter 2021-22 in this sensitivity. In the most extreme year simulated, **102 hours** of structural shortage were obtained. In the 'high-impact low-probability sensitivity' scenario for winter 2021-22, the P95 is equal to **12 hours** while the P10 & P50 are both equal to 0 hours.

Furthermore, Figure 6.19 and Figure 6.21 show that the amount of Energy Not Served (ENS) is on average **1.3 GWh** over the winter and **3 GWh** in P95.

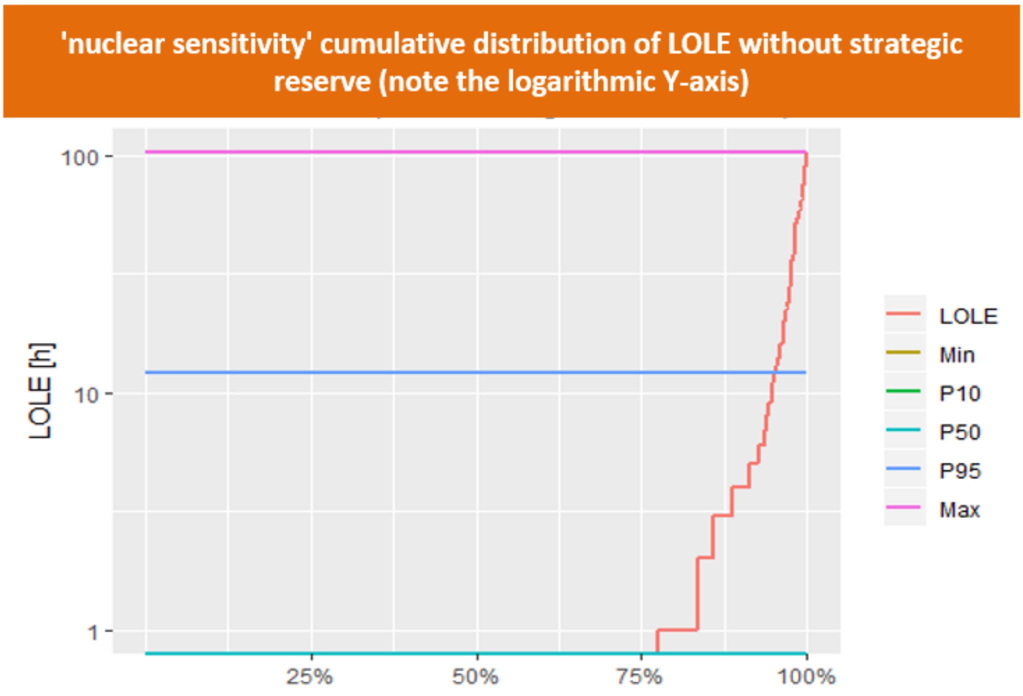


Figure 6.20

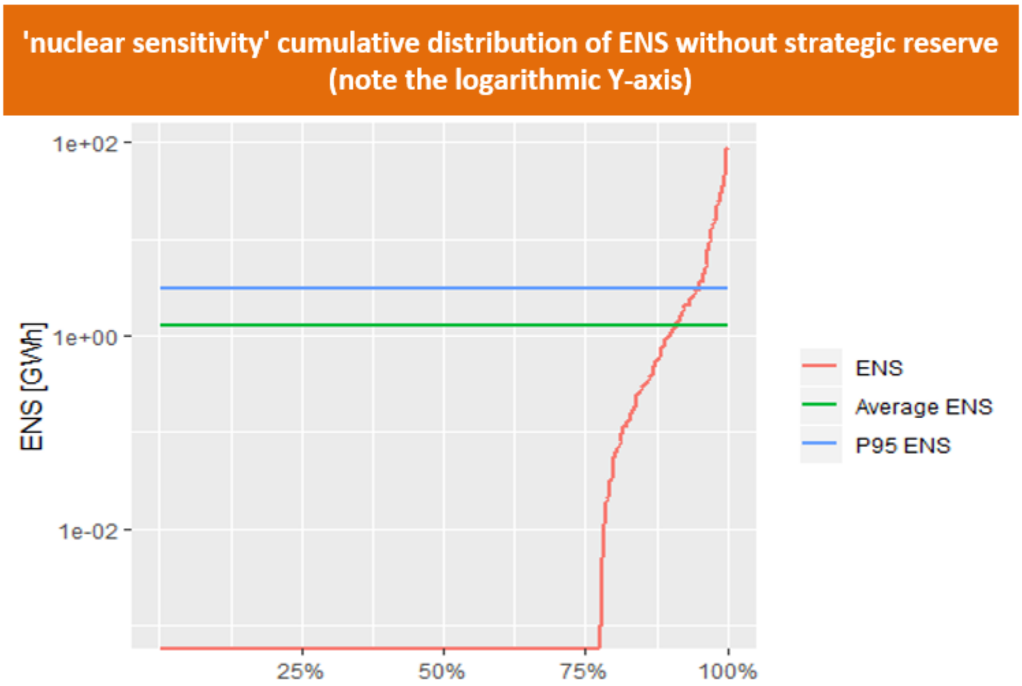


Figure 6.21

6.6 Results for winter 2022-23 'base case'

6.6.1 Changes in Belgian assumptions

The 'base case' for winter 2022-23 follows the assumptions presented in chapter 3. The main changes of winter 2022-23 are:

- Regarding the planned unavailabilities of the thermal fleet, REMIT was consulted yet showed no planned outages (yet). In order to keep consistency with the analyses for winter 2020-21 and winter 2021-22 presented above, it was chosen not to make the switch to statistical planned outage modelling. Hence, no planned outages are integrated in the model for winter 2022-23.
- 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 (1010 MW for winter 2022-23);
- An increase in domestic renewable energy generation;
- Total demand growth is approximately 0.4%/year on average between the years 2020 and 2023;
- 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, plus the flow through Nemo Link®.

6.6.2 Calculation of LOLE, ENS and number of activations

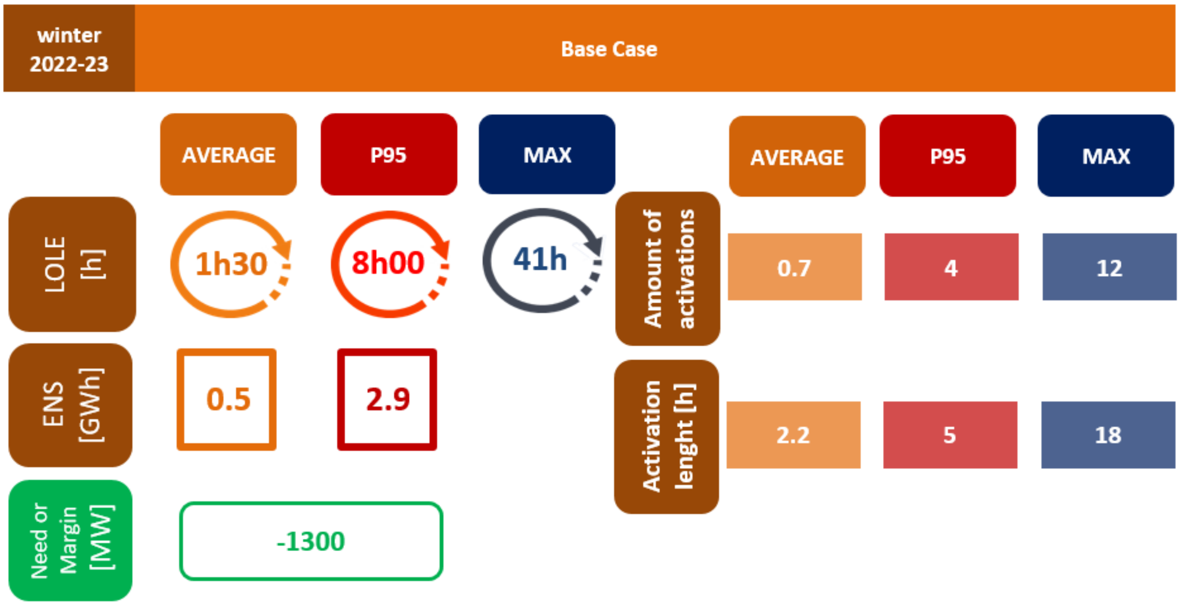


Figure 6.22

The resulting values are shown in Figure 6.22 . The LOLE average for winter 2022-23 in the 'base case' is about **1 hour 30 minutes** and the percentile 95 is **8 hours**. These results are lower than the criteria defined by law, and the margin corresponding to the 2022-23 'base case' scenario is **1300 MW,** both for the average as well as for the percentile P95 indicator.

As can also be observed in Figure 6.22, the number of activations of a possible volume of strategic reserve would be very low: **0.7 times** per year on average, 4 **times** in P95 and **12 times** in the most extreme 'Monte Carlo' year 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 **18 hours** without interruption. The average of the activation length is around **2.2 hours**.

Figure 6.23 shows the cumulative distribution of the LOLE over all 'Monte Carlo' years simulated for the 'High Impact, Low Probability' scenario when no volume or margin was added. The probability of having at least one hour of structural shortage amounts to **22%** for winter 2022-23 in this scenario. In the most extreme year simulated, **41 hours** of structural shortage were obtained. However, this is very rare, as shown by the P95 which is limited to **8 hours**. In the 'base case' scenario for winter 2022-23, the P10 & P50 indicators are all equal to **0 hours**.

Furthermore, Figure 6.22 and Figure 6.24 show that the amount of Energy Not Served (ENS) is limited to a value of **0.5 GWh** over the winter on average and to **2.9 GWh** in P95.

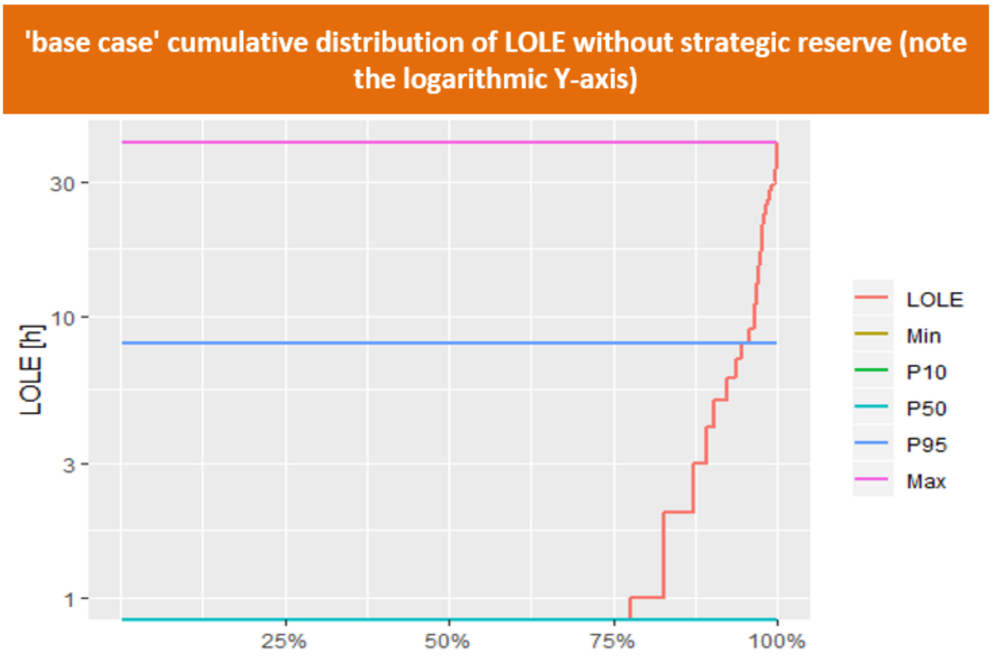


Figure 6.23

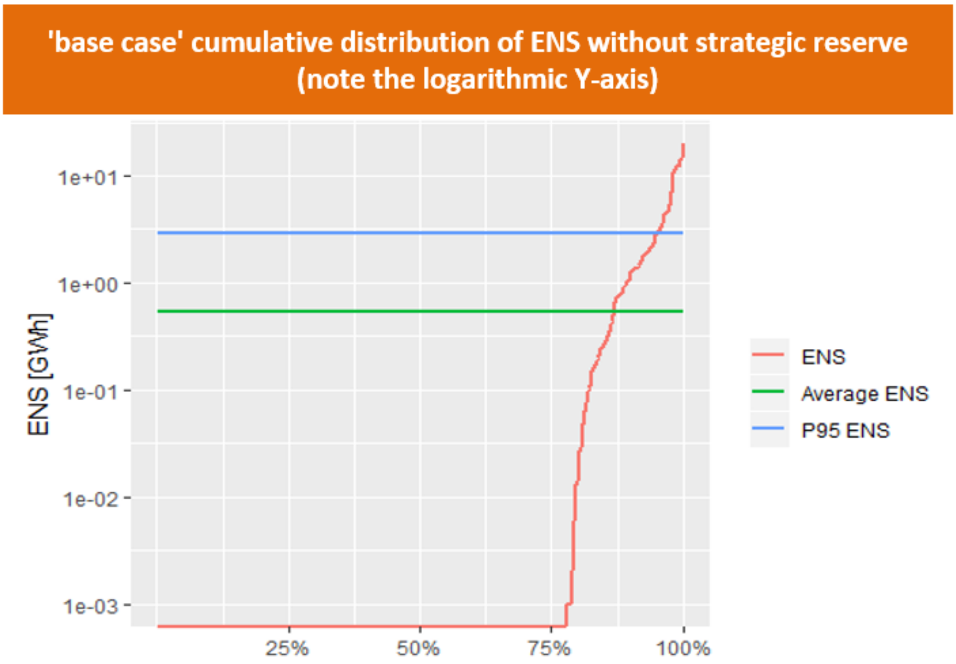


Figure 6.24

6.7 Results for winter 2022-23 'High Impact, Low Probability' scenario

6.7.1 Description of the nuclear sensitivity

While the nuclear phase-out may warrant a change of the 'nuclear sensitivity' by means of a homothetic scaling (e.g. factor 5/6th), this would break consistency with previous winters for two reasons. Firstly, such a scaling would result in a sensitivity of 1250 MW which is impossible to obtain in the current configuration of nuclear generation units. Secondly, the lack of periodic outages in REMIT is inconsistent with previous winters.

It is deemed that future periodic outages might well counter a reduction of 250 MW in the nuclear sensitivity. To anticipate this, the same sensitivity as defined in section 6.3.1 is analyzed in winter 2022-23. This means an additional 1.5 GW of nuclear generation in Belgium and 3.6 GW of nuclear generation in France is considered out of service for the whole of the winter.

An overview of nuclear availability in the 'High Impact, Low Probability' scenarios for all 3 winters is given in Figure 6.25. As stated before, the nuclear availability is made up of 3 components: planned outages, forced outages & an additional volume as imposed by the 'nuclear sensitivity'. It can be seen from this figure that this approach is best in line with previous winters, whilst also incorporating the effect of the nuclear phase-out.

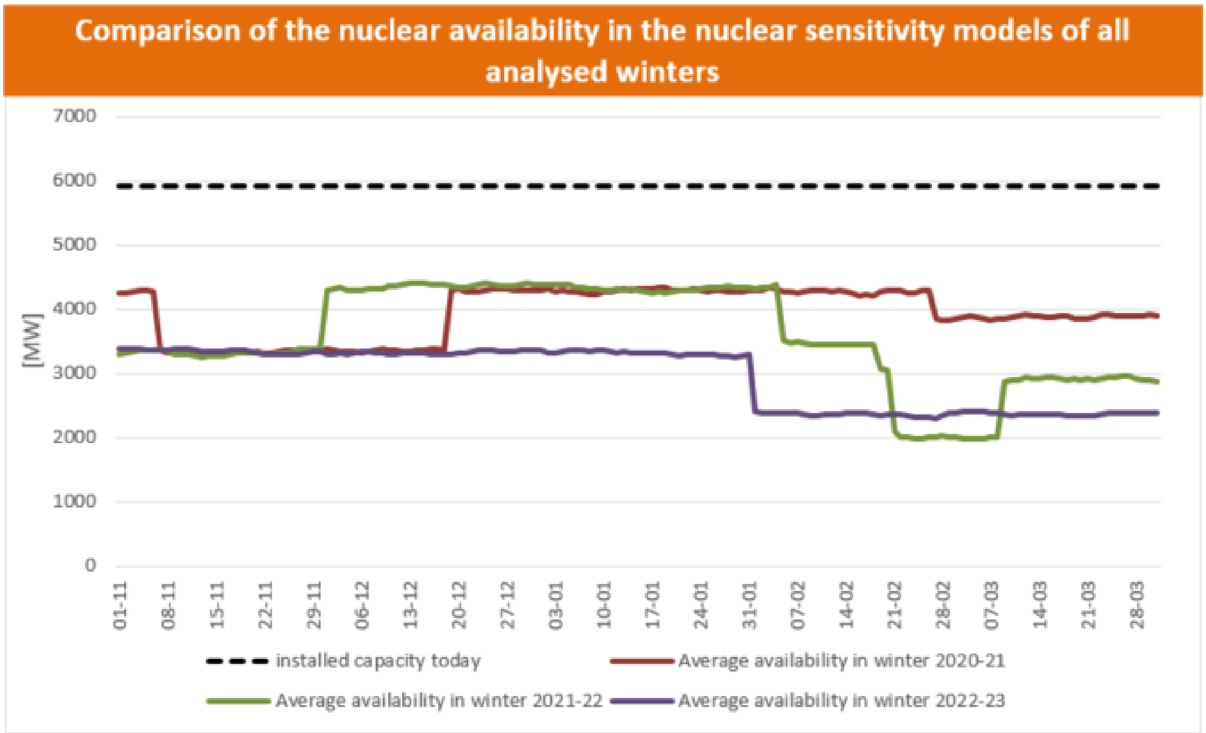


Figure 6.25

6.7.2 Calculation of LOLE, ENS and number of activations

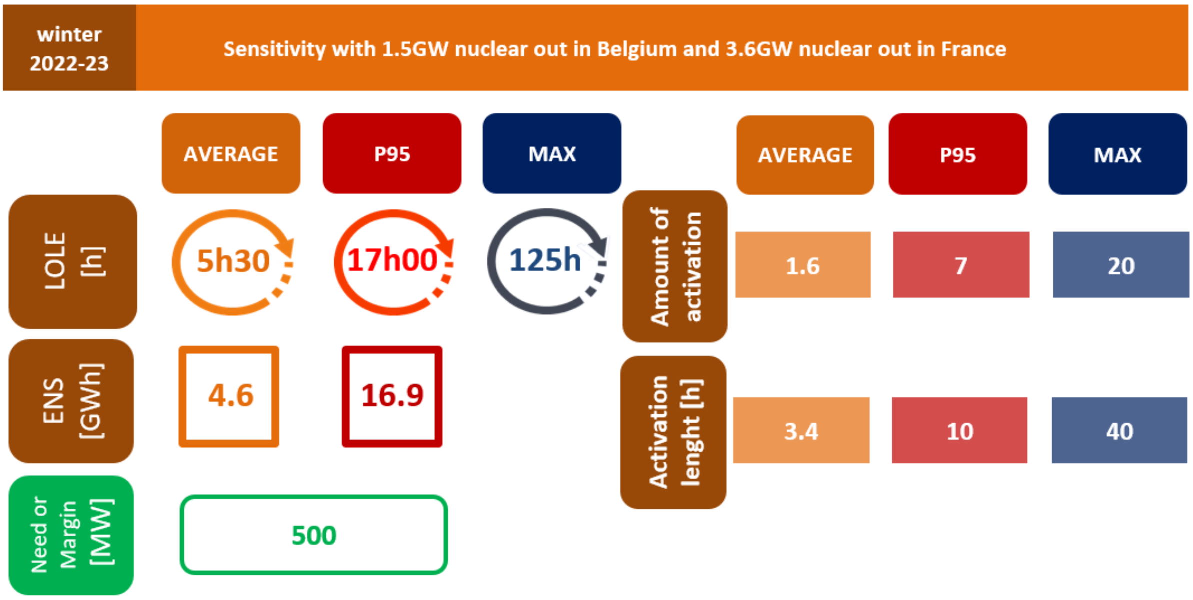


Figure 6.26

The resulting values are shown in Figure 6.26 for the sensitivity. The LOLE average for winter 2022-23 in this sensitivity is **5 hour and 30 minutes** and the percentile 95 is **17 hours**. The average LOLE results are higher than the criteria defined by law, and the need corresponding to the 2022-23 'high-impact low-probability' scenario is **500 MW.**

As can also be observed in Figure 6.26, the number of activations of a possible volume of strategic reserve would be low: **1.6 times** per year on average, **7 times** in P95 and **20 times** in the most extreme 'Monte Carlo' year 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 **40 hours** without interruption. The average of the activation length is around **3.4 hours**.

Figure 6.27 shows the cumulative distribution of the LOLE over all 'Monte Carlo' years simulated for the 'High Impact, Low Probability' scenario when no volume or margin was added. The probability of having at least one hour of structural shortage amounts to **41%** for winter 2022-23 in this sensitivity. In the most extreme year simulated, **125 hours** of structural shortage were obtained. However, this is very rare, as shown by the P95 which is limited to **17 hours**. As a consequence, in this scenario, the P10 & P50 indicators are all equal to **0 hours**.

Furthermore, Figure 6.26 and Figure 6.28 show that the amount of Energy Not Served (ENS) is limited to a value of **4.6 GWh** over the winter on average and to **16.9 GWh** in P95.

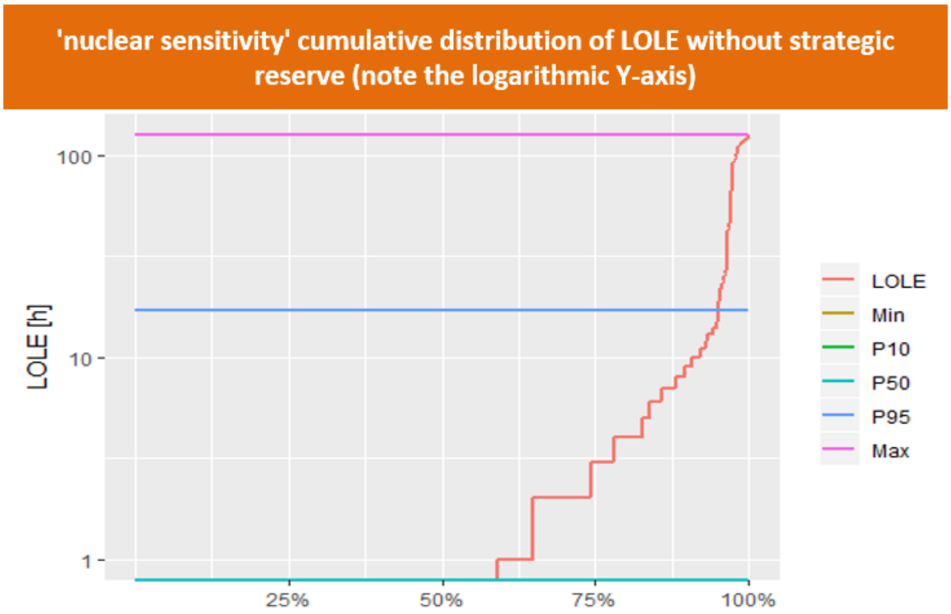


Figure 6.27

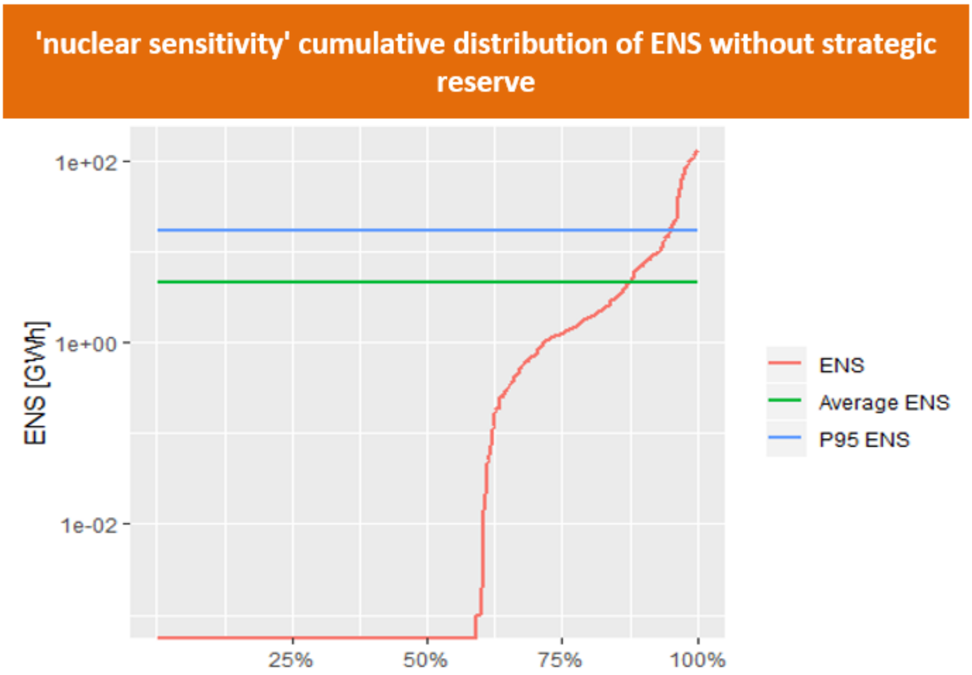

'nuclear sensitivity' cumulative distribution of ENS without strategic reserve
1e+02
1e+00
1e-02
ENS [GWh]
25%
50%
75%
100%
ENS
Average ENS
P95 ENS

Figure 6.28

7. Conclusions

This report gives an estimate of the needed capacity of strategic reserve in order to maintain Belgium's adequacy, in compliance with the criteria defined by law for winter 2020-21 and provides an outlook also for winter 2021-22 and winter 2022-23. If no volume need is identified, the margin for each scenario was also calculated.
Elia performed a probabilistic analysis following the timetable set out in the law to allow the Federal Minister for Energy to take a decision on the volume needed by 15 January 2020.

The assumptions used in this report were defined end of October 2019, taking into account remarks received during the public consultation on input data. The assumptions include the best available estimates for installed generation capacities in Belgium and neighbouring countries at the time of collecting the inputs.

Furthermore, according to Article 7quater of the Electricity Act, the Minister can review the volume for the strategic reserves no later than 1 September 2020 for winter 2020-21. Such a decision by the Minister shall 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 shall exclusively take into account the following information, which is sufficiently relevant to the capacity and use of facilities for production, storage, consumption or transmission of electricity or natural gas or related to the capacity and use of LNG facilities, 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 said entity to Elia;
- any information of which the Minister explicitly requests Elia to take it 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, which was discussed with FPS Economy as requested by law and submitted to a public consultation ending on 25 September 2019.
It includes the following assumptions (only the main drivers for Belgium are listed below):

- a relatively limited growth of 0.4% per year in Belgium's total electricity demand;
- the latest public information (REMIT) regarding the future maintenance planning of the nuclear units is considered (as provided on the transparency websites of the nuclear units' owners dated 15 October 2019) for Belgium and France. On top of any planned outages, 'base case' simulations account for a normal Forced

Outage rate. 'Exceptional' outages are not covered by this normal Forced Outage rate, but are treated separately through the 'High Impact, Low Probability' sensitivity described below;

- installed capacity forecasts for photovoltaic and onshore wind generation based on the latest data from the regions, combined with a best estimate made by Elia and FPS Economy about offshore wind generation;
- commercial exchanges between Belgium and the other CWE countries are modelled using historical flow-based domains available, modified to take into account full grid availability in Belgium and adding the impact of planned HTLS upgrades;
- the availability of the new interconnector with Great Britain (Nemo Link®) with a capacity of 1000 MW for all winters, modelled as an NTC;
- the availability of the new interconnector with Germany (ALEGrO) with a capacity of 1000 MW for all winters, modelled by means of a modification of the FB domains;
- a maximum global simultaneous import capacity of 6500 MW for Belgium for winter 2020-21 and 2021-22 is considered. The limit is increased to 7500 MW for winter 2022-23. This limit applies to the sum of the imports from CWE and the flow on the Nemo Link® interconnector;
- a stable trend in the installed thermal generation facilities in Belgium between winter 2020-21 and all consecutive winters. This entails the availability of Vilvoorde in OCGT operation, and both Seraing and Drogenbos in CCGT operation. Additionally, some smaller units will be available as well: Angleur 3, Ham, Izegem, TJ Ixelles and TJ Deux-Acren. Compared to last year's forecast, Awirs will not be available for any of the three winters as its permanen decommissioning has been announced.
- furthermore, the most 'up-to-date' information is considered regarding maintenance planning, as provided on the transparency websites of the thermal units' owners (dated 15 October 2019).

For the 'base case' scenario in winter 2020-21, as defined in this report, the need for strategic reserve is equal to 0 MW, as a margin of **3200 MW** was obtained for Belgium.

For the 'base case' scenario in winter 2021-22, as defined in this report, the need for strategic reserve is equal to 0 MW, as a margin of **2800 MW** was obtained for Belgium.

For the 'base case' scenario in winter 2022-23, as defined in this report, the need for strategic reserve is equal to 0 MW, as a margin of **1300 MW** was obtained for Belgium.

7.2 'Sensitivity' to the 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 that occurred during recent winters. Therefore, the decision was made to analyse a sensitivity in which the Belgian and French nuclear availability is aligned with the historical availability since 2012.
For Belgium, a sensitivity in which 1.5 GW of nuclear production capacity is out of service for the entire winter (on top of the normal forced outage rates and planned maintenance as above mentioned 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. For France, the same analysis resulted in 3.6 GW of nuclear production 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. This sensitivity was also retained for winter 2021-22 and winter 2022-23. For the latter, it was decided not to scale the availability to the reduced total installed capacity (taking into account the start of the nuclear phase-out) to offset the absence of information on planned outages for this winter.

For this 'High Impact, Low Probability' scenario, as defined in this report:
- a margin of **100 MW** is obtained for Belgium in winter 2020-21;
- a margin of **200 MW** is obtained for Belgium in winter 2021-22;
- the need for strategic reserve is equal to **500 MW** for Belgium in winter 2022-23.

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:

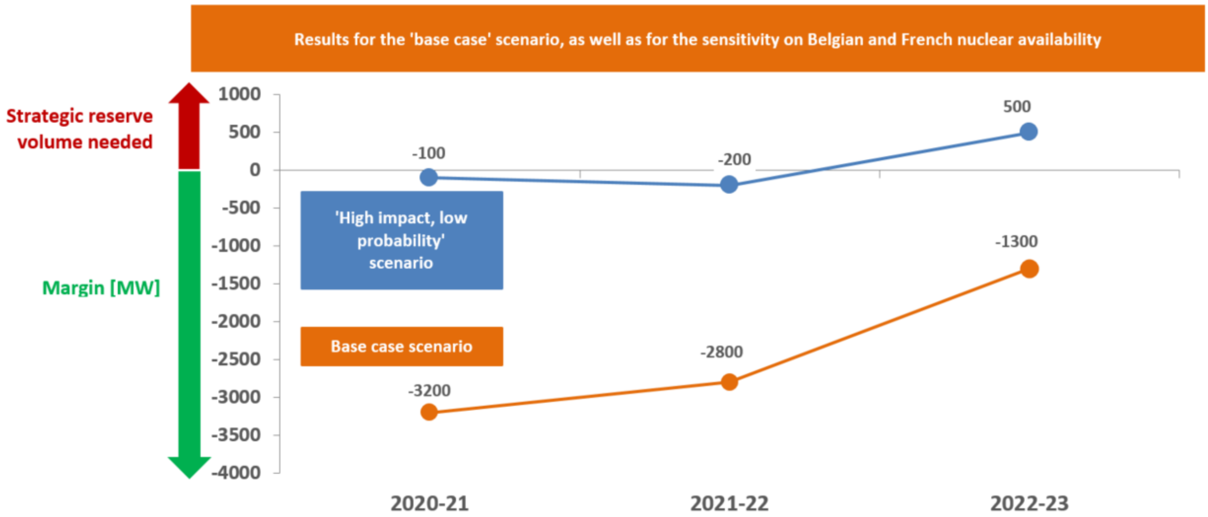


Figure 7.1

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 the '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

A probabilistic risk analysis requires the construction of a large number of future states. Each of these states can then be analysed to determine the adequacy indicators. We begin this section by indicating **which variables are taken into account** (section8.1.1.1). Next, we illustrate how both **electricity production** (section 8.1.1.2) and **electricity consumption** (section 8.1.1.3) are modelled in general. Finally, section 8.1.1.4 elaborates on how the different variables are **combined into 'Monte Carlo' years**.

8.1.1.1 Variables taken into account for the simulation

The key variables in this study can be subdivided into two categories: climatic variables and the availability of the generation facilities.
There are mutual correlations between the following **climatic variables**:

- hourly time series for wind energy generation;
- hourly time series for PV[26] solar generation;
- daily time series for temperature (these can be used to calculate the hourly time series for electricity consumption);
- monthly time series for hydroelectric power generation.

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

- parameters relating to the **availability of thermal generation facilities** on the basis of which samples can be taken regarding power plants' unavailability.

Correlation of climatic conditions

The various meteorological conditions having an impact on renewable generation and electricity consumption are not independent of each other. Wind, solar radiation, temperature and precipitation are correlated for a given region. In general, high-pressure areas are characterised by clear skies and little wind, while low-pressure areas have cloud cover and more wind or rain. Given the very wide range of meteorological conditions that countries in Europe can experience, it is very hard to find clear trends between meteorological variables for a given country. Figure 8.1 attempts to show the non-explicit correlation between wind production, solar generation and temperature for Belgium. The graph presents the seven-day average for these three variables for Belgium based on 40 climatic years. The hourly or daily trends cannot be seen as the variables were averaged by week but various seasonal and high-level trends can be observed:

[26] PV: photovoltaic

- The higher the temperature, the lower the level of wind energy production. During the winter there is more wind than in the summer;
- The higher the temperature, the higher the level of PV solar generation. This is a logical result from the fact that more solar generation goes on during the summer and inter-season months (see Figure 8.5);
- When the level of wind energy production is very high, the level of PV solar generation tends to fall;
- In extremely cold periods, wind energy production falls while there is a slight increase in PV solar energy generation. This is a key finding that will affect adequacy during very cold weather.

The various meteorological data are also geographically correlated as countries are close enough to each other to be affected by the same meteorological effects. A typical example of this is the occurrence of a tight situation due to a cold spell which first spreads over western France, then over Belgium and after that over Germany. It is essential to maintain this geographical correlation between countries in terms of climate variables.

Given the high amount of renewable energy from variable sources that is installed each year in Europe and the high sensitivity to temperature of some countries' electricity demand, it is essential to maintain the various geographically and time-correlated weather conditions in the assessment.

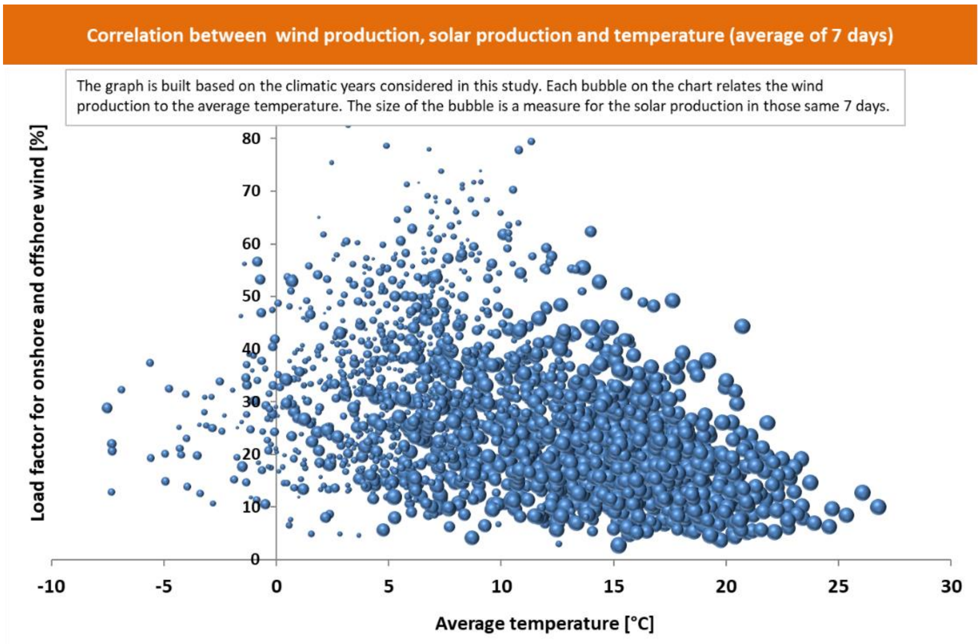


Figure 8.1

The climatic variables in this study are modelled on the basis of 33 historical winters, namely those between 1982 and 2015. The historical data for temperature, wind production, and solar production are procured in the context of ENTSO-E. These data are used *inter alia* in the ENTSO-E MAF (see section 1.8.4) and the ENTSO-E TYNDP market simulations.

For the modelling of the hydroelectric power production, Elia has performed an analysis based on statistical data provided by TSOs to ENTSO-E combined with precipitation data from the NCDC[27] database of the United States [17]. For years 1991 to 2015, the hydroelectric power generation data come from ENTSO-E data portal [26]. The data for the other years, i.e. from 1982 to 1990, are reconstructed on the basis of the historical precipitation data for each country (NCDC).

The availability data for Belgian **thermal generation** facilities comes from a historical analysis based on the years from 2007 to 2016 (see section 3.1.3.2). For the other countries, the unavailability data come from the ENTSO-E studies [16], [24], [26] and/or data from bilateral contacts with TSOs.

The climatic conditions are modelled using 33 (historical) climatic winters.

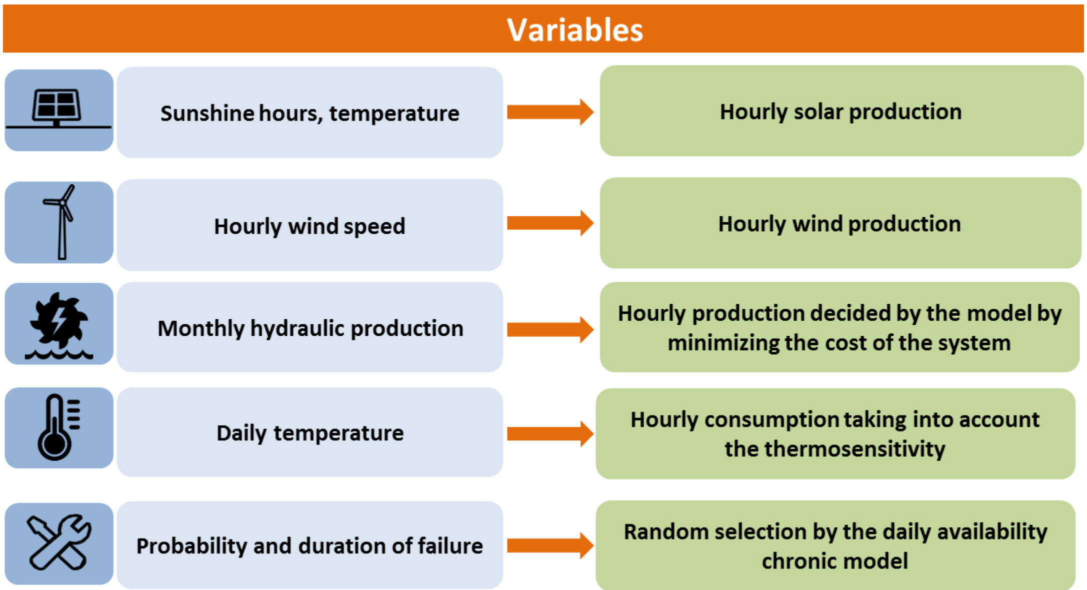


Figure 8.2

Variability of wind energy production

Wind energy production depends on the wind speed where the wind turbines are located. Figure 8.3 shows the wind power load factor each month[28] for the 34 historical years based on which the 33 winters used in the assessment are created. Here the average value, the 10th percentile (P10) and the 90th percentile (P90) are marked for each month in the graph. The graph shows that the level of wind energy production is higher in the winter than in the summer.

In addition to the variability depending on the month, wind energy production may fluctuate considerably across the same day, as illustrated by Figure 8.4.

[27] NCDC: National Climatic Data Centre

[28] The load factor is the ratio between the electrical energy actually generated during a given period and the energy which would have been generated if the facility had been operating at nominal capacity during the same period.

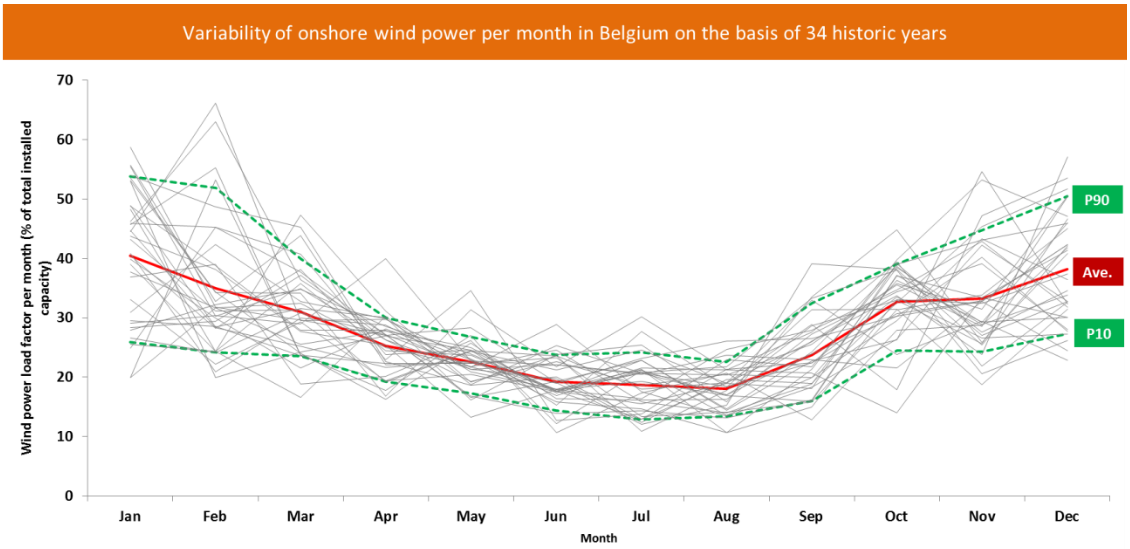


Figure 8.3

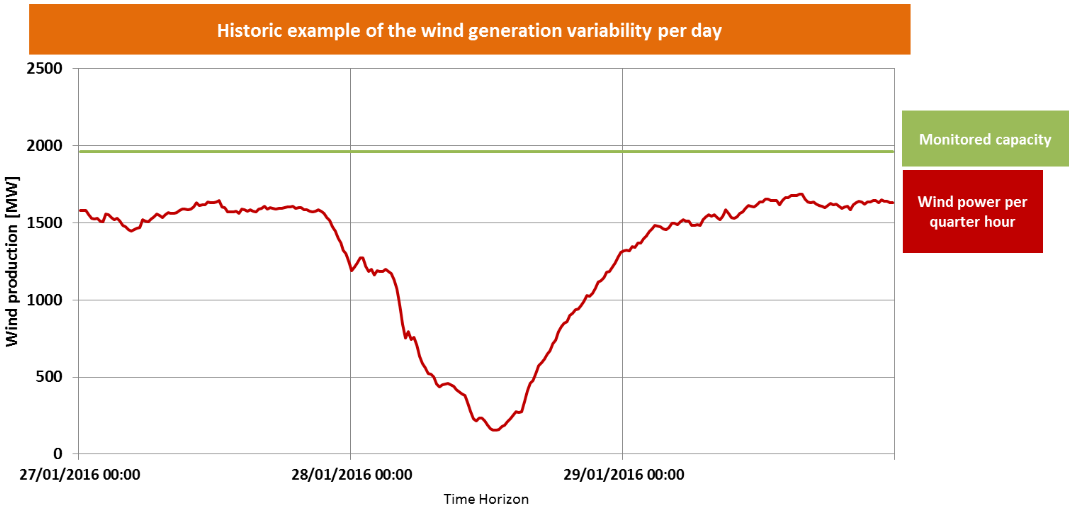


Figure 8.4

The greater the installed capacity of the wind farm, the more wind energy contributes to helping ensure system adequacy. If there is little or no wind, other generation units will have to be activated to meet electricity demand.

Variability of PV solar generation

PV solar generation is subject to sunshine variability. The average level of generation is higher in the summer than in the winter:

- the number of hours of solar radiation rises in the summer (reaching a peak at summer solstice around 21 June and a low at winter solstice around 21 December);
- the incident solar radiation is greater at summer solstice than at winter solstice (as the sun is higher in the sky);
- the weather (for example the sky being covered by clouds) has a major impact on solar generation;

— the performance depends on, among other things, the outside temperature, meaning that the performance level is higher in cold weather.

Figure 8.5 shows the solar generation load factor for an average day in each month of the year in Belgium.

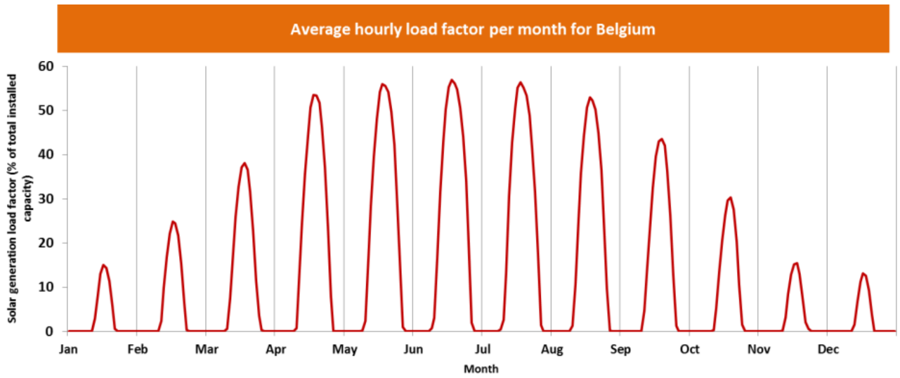


Figure 8.5

As PV solar generation levels are low during the winter, solar generation's contribution to security of supply is fairly limited. Furthermore, the generation level is zero during the winter peaks because by then the sun has already gone down.

Variability of temperature

The temperature is decisive in determining the risk of a structural shortage due to the sensitivity of electricity demand to temperature; the colder the weather, the higher the level of electricity consumption (see section 8.1.1.3).

Figure 8.6 shows, for every winter between 1975 and 2015, the number of days when the average day temperature was below 0°C (as measured at the Royal Meteorological Institute in Uccle). The colour code indicates how far below zero this was (the darker the colour, the lower the temperature).

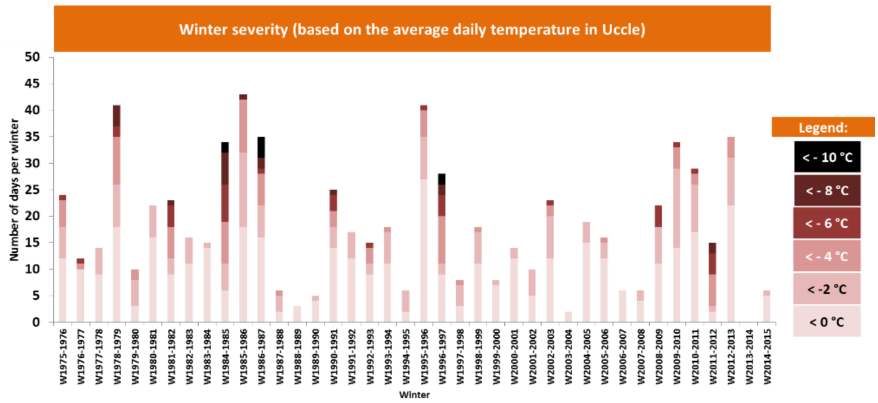


Figure 8.6

Figure 8.7 gives the distribution of the equivalent daily temperature observed in the period from 1975 to 2015, indicating for each day the P10-P90 range, P40-P60 range and minimum and maximum range. The temperature observed in winter 2015-16 is also shown. Statistically, the coldest periods in Belgium are in December and January although cold spells can also take place in other months.

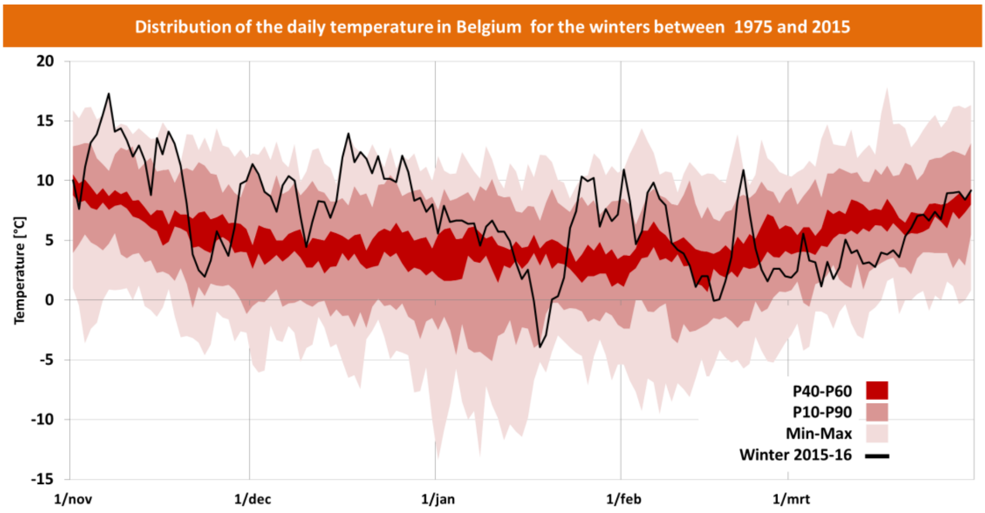


Figure 8.7

What is a cold spell?

A cold spell is a weather phenomenon defined by the rate at which the temperature falls and the associated minimum value to which it falls. These criteria are defined depending on the geographical region and time of year. For Belgium, a cold spell is described as a period where the average daily temperature is lower than -2°C for at least 7 consecutive days **and** when at least one of the following conditions is met:

- the low temperature during this period dropped at least twice to below -7 °C;
- the high temperature remained below 0 °C for 3 days during the period too.

Physically, the cold wave is characterised by 3 distinct phases:

1. The **cooling phase or cold advective phase** lasts around 2-3 days;
2. The **self-supply of this cold phase or the radiative phase** having a highly variable duration, from a few days to weeks. Its duration and its associated strength defines the intensity of the cold snap;
3. The **heating phase or hot advective phase** with a very fast duration, typically below 24 hours or also few days.

Figure 8.8 illustrates the different cold spells that have occurred in Belgium between 1975 and 2012. The last cold snap was recorded in winter 2017-2018 and lasted 15 days.

Source and more information can be found on the meteobelgique.be website [15].

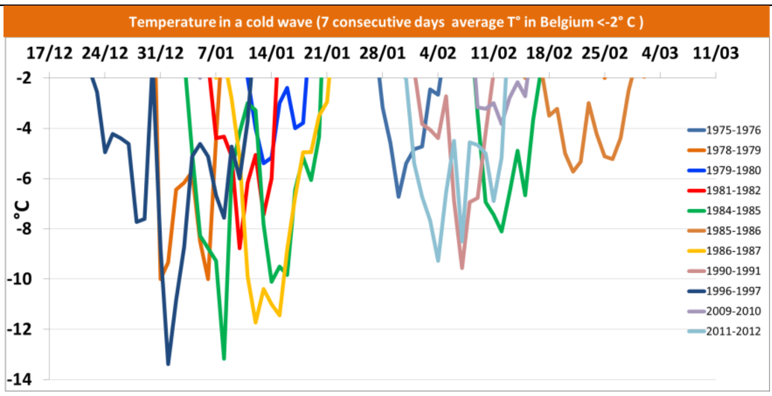


Figure 8.8

Variability of hydroelectric power generation

Hydroelectric power generation (excluding pumped-storage power plants) depends on the supply of water in the reservoirs (precipitation, melting of snow or glaciers), the size and management of the reservoirs and the location of the various hydroelectric power plants.

A dry year reduces the generation potential of hydroelectric power plants compared to an average precipitation or wet year.

Figure 8.9 shows that hydroelectric power generation (excluding pumped-storage power plants) in the CWE area (plus Switzerland) has a historical variability level of 4 TWh per month (difference between the 10th and 90th percentiles). The difference between annual generation levels in the driest year (2011) and the year with the most precipitation (2001) comes to almost 50 TWh in the area under consideration.

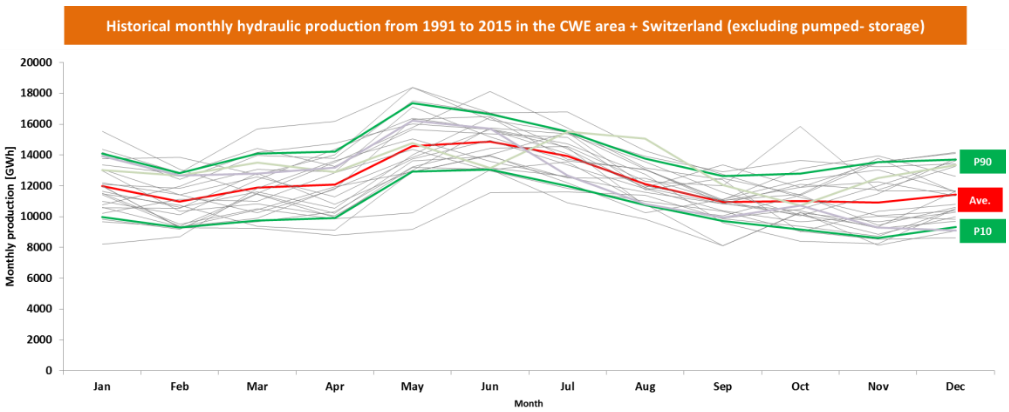


Figure 8.9

Variability in the availability of thermal generation facilities

As regards the availability of thermal generation facilities, random samples are taken by the model on the basis of historical parameters relating to the probability and length of the unavailability. For more information concerning the exact modelling, see section 8.1.1.2.2.

Other variables (see below) might have a potential impact on security of supply but are disregarded in the 'base case' of this study. However, some events listed below are taken into consideration as a sensitivity for this study.

The simulations performed in this study disregard, in the 'base case', the following events (this list is not meant to be exhaustive):

— long-term power plant unavailability (sabotage, political decisions, strikes, maintenance due to inspections, bankruptcy, terrorist attacks, etc.). Those events if quantified are assessed as sensitivities;
— interruption of the fuel supply for the power plants;
— extreme cold freezing water courses used for plant cooling;
— natural disasters (tornadoes, floods, etc.).

8.1.1.2 Modelling of electricity production

This section elaborates on the modelling of electricity generation for use in market simulations. First, section 8.1.1.2.1 discusses the modelling of wind and solar electricity production. Second, both the modelling of individually modelled thermal production (section 8.1.1.2.2), and profiled thermal production (section 8.1.1.2.3) are elaborated upon. Third, the modelling details of hydroelectric power production are given in section 8.1.1.2.4.

8.1.1.2.1 Wind and solar electricity production

As already indicated in 8.1.1.1, hourly wind energy production and solar generation data used are historical data for these production types. The forecasts of installed capacity for each simulated country are combined with this historical data to obtain production time series for onshore wind, offshore wind and photovoltaic production. This process is illustrated in Figure 8.10.

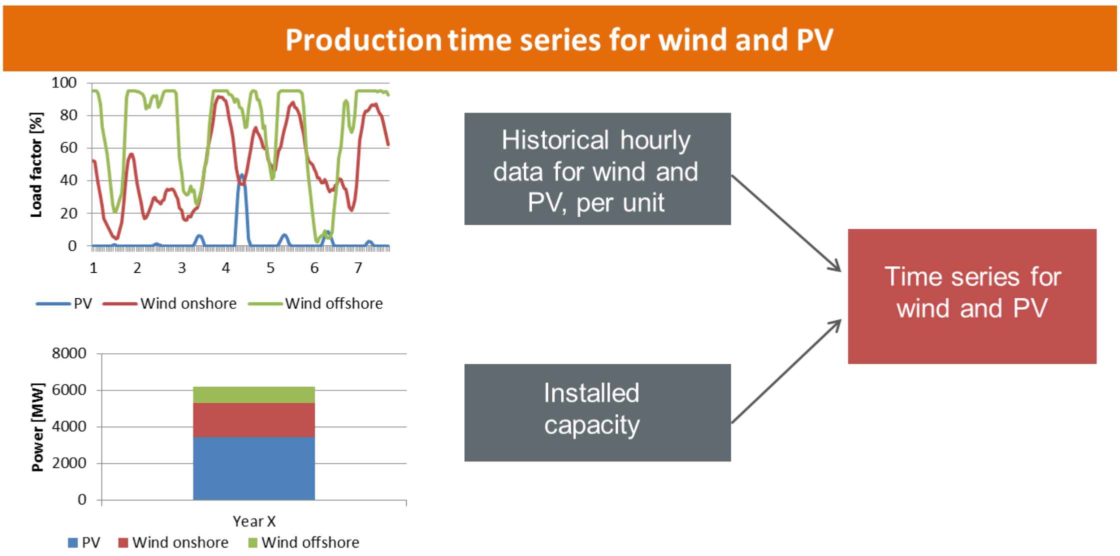


Figure 8.10

8.1.1.2.2 Individually modelled thermal production

Large thermal generation units, independent of their production types, are modelled individually, with their specific technical and economic characteristics. Their individual availability is determined by a probabilistic draw for each 'Monte Carlo' year (see section 8.1.1.4) based on historical availability rates. This way, a very high sequence of availabilities can be drawn for each unit to be used in the simulations.

Figure 8.11 shows an example of a distribution of various samples for thermal units with individual modelling for a given month. Extreme events (for example, the loss of various power plants) may significantly reduce available capacity. These events may lead to a structural shortage.

The percentiles indicated in the graph correspond to the daily distribution of the availability of power plants based on a large number of random samples for availability. The different lines represent a random draw on the availability of the power plants (total amount of available capacity that can be dispatched for a given day).

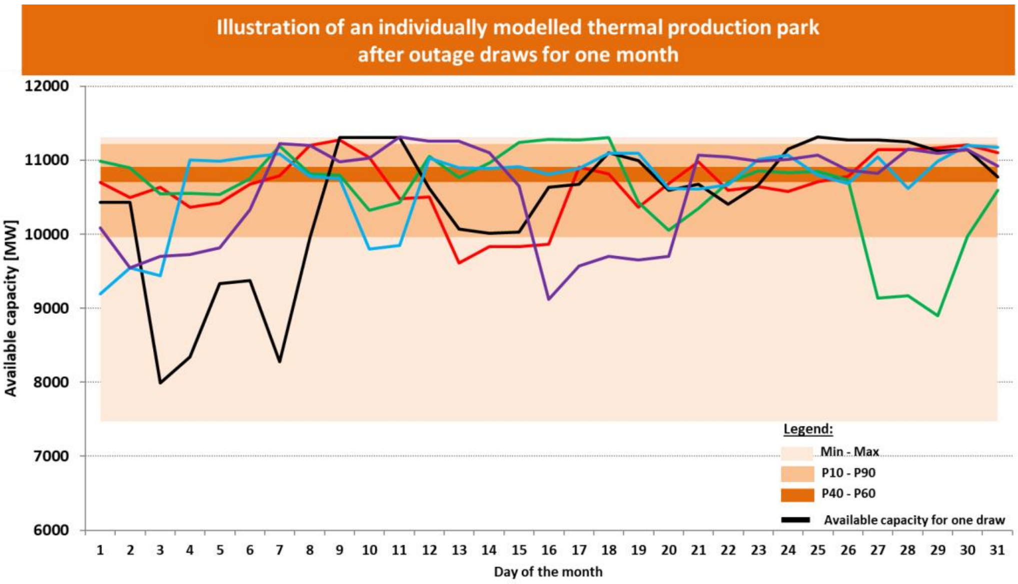


Figure 8.11

8.1.1.2.3 Profiled thermal production

Small thermal generation units are modelled in an aggregated way by using a fixed generation profile. Examples of such small thermal generation units are small biomass installations or combined heat and power (CHP) generation units. The availability of these smaller units is directly taken into account in the generation profile, and is therefore the same for all 'Monte Carlo' years. The different generation profiles for each country are collected through bilateral contacts or within the context of ENTSO-E.

In Belgium, units without a CIPU contract are also modelled using profiles. However, in contrast to the modelling of profiled thermal generation in other countries, temperature-dependent generation is taken into account for these units. Three generation types are differentiated in Belgian profiled thermal generation: biomass, CHP and waste. For each of these types, available power output measurement data was analysed for a period of up to five years. A correlation analysis on the relation between these units' output and the corresponding daily temperature, load and electricity price showed a strong inverse link between generation and temperature. Furthermore, because no significant difference in aggregated behaviour between these categories was discovered, in terms of load factor or temperature correlation, and to limit the upscaling error due to the ratio of installed capacity over measured capacity, it was decided to combine these three categories into a single generation profile. Averaged over 33 climatic years, this gives the average hourly generation profile, displayed in Figure 8.12. This profile was also made public in the public consultation on the data used in this analysis. Figure 8.13 illustrates temperature-dependent generation for three randomly selected days in three climatic years.

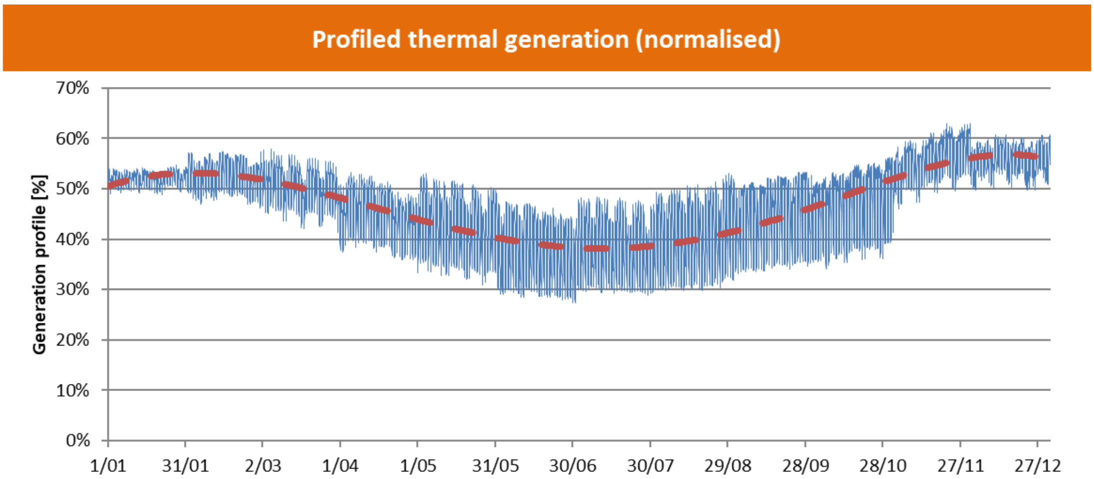


Figure 8.12

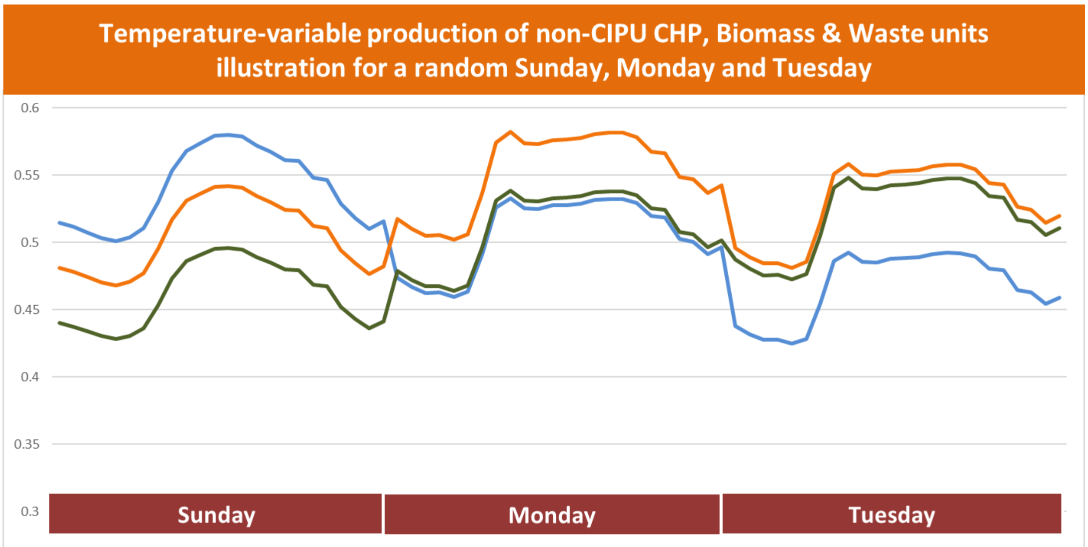


Figure 8.13

8.1.1.2.4 Hydroelectric power production

Four types of hydroelectric power generation are taken into account:

- pumped-storage without inflow;
- pumped-storage with inflow;
- run-of-river;
- reservoir power generation with natural inflow.

Of these four types, only pumped storage without inflow, and run-of-river hydroelectric power generation are present in Belgium. The other two are is more common in countries with greater natural differences in elevation.

Pumped-storage power generation functions by pumping water to higher reservoirs when electricity is cheap, and by turbining this water back to lower reservoirs when electricity is more expensive. The model assumes an efficiency of 75% for the round-trip process. Depending on the size of the pumped storage reservoirs as well as their operating mode, their dispatch can differ. The model differentiates between pumped-storage generation units which optimise their dispatch on a daily basis and those which optimise their dispatch on a weekly basis.

A more conventional form of hydroelectric power generation converts the energy from the natural flow of water into electricity. If a **reservoir** is present, the energy can be stored for a specific amount of time, allowing it to be dispatched at the economically best moment. These reservoirs are taken into account in the simulation model, together with their inflows.

A hybrid form is **pumped-storage with natural inflows,** which is very similar to reservoir power generation, but whereas the latter only has turbines to generate electricity, the former also has large pumps to pump water back up into the basin at times of low electricity prices.

If no reservoir is present, the generation type is called **run-of-river**, and no arbitrage can be effected when the power is injected into the grid. This type of hydroelectric power production is modelled through the use of profiles.

8.1.1.3 Modelling of electricity consumption

The hourly total electrical load of each 'Monte Carlo' year for each simulated market node is forecast for the period under study. Electricity consumption profiles are constructed in a way a similar to that for all simulated market nodes29 and can be divided into the three separate steps shown in Figure 8.14.

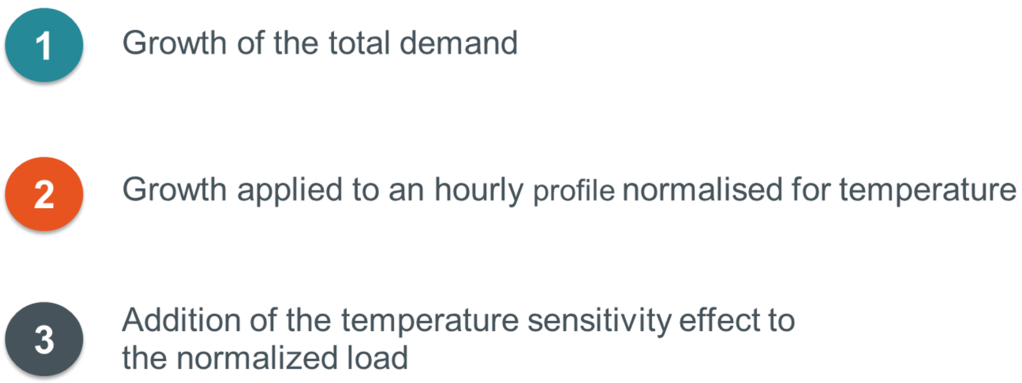


Figure 8.14

The process constructs one hourly total load profile per market node for each climatic condition, resulting, in the case of this study, in demand profiles corresponding to 33 historical winters (see section 8.1.1.1). Figure 8.15 gives a detailed overview of the construction process of the hourly load profiles. The three separate steps are detailed respectively in section 8.1.1.3.1, section 8.1.1.3.2 and section 8.1.1.3.3.

Elia has aligned its method for electricity load modelling with the method developed in the context of the ENTSO-E adequacy study MAF. This improves coherence among different studies and allows for efficient continuous development of the method.

[29] An exception is made for France in the current analysis. Please refer to section 4.1.2 for more information.

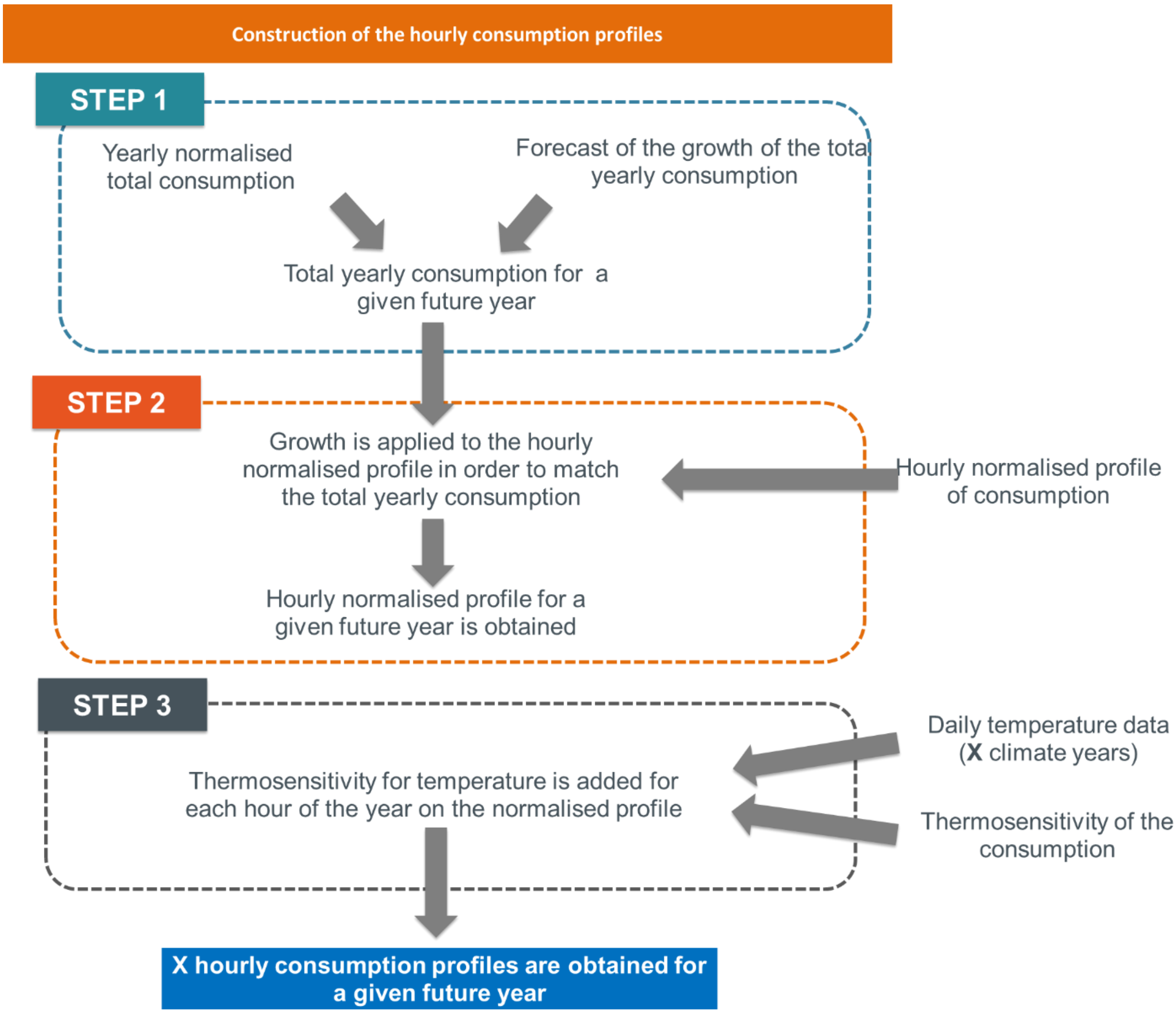


Figure 8.15

8.1.1.3.1 Growth of the total demand

The first step consists of forecasting the annual total electrical load for a given country. After normalising the most recent historical total load for temperature, an estimate of the growth of total demand is taken. Annual normalised demand fluctuations are mainly due to economic indicators (GDP, growth of population, industry, etc.), energy efficiency improvements and electrification (new usage of electricity, switching between energy sources). By applying the forecast growth of total demand on the most recent historical total load, normalised for temperature, a forecast of future total load is obtained.

8.1.1.3.2 Growth applied to an hourly profile normalised for temperature

Once the total annual normalised demand has been forecast for the future years, a normalised hourly consumption profile corresponding to a future year can be constructed. In order to compute it, the electricity consumption profile of the country in question is taken. This typical profile gives for every hour of the year, the expected demand based on historical data and on the average historical temperatures observed. This profile, called the profile normalised for temperature, is then scaled in order to meet the forecast total demand determined in the first step. Several methods can be used to construct a profile normalised for temperature. The method used in this analysis was developed in the context of the ENTSO-E adequacy study MAF (see section 1.8.4).

8.1.1.3.3 Addition of the temperature sensitivity effect to the normalised load

For each hour, the temperature sensitivity effect is applied to the normalised load profile. In the context of the ENTSO-E study, in 2019 a new framework for incorporating the temperature sensitivity of the load was developed. This new method has the following advantages over the previous load profiling framework:

- Multiple historical climate and load time series are used to derive forecast load profiles for each market node.
- Automatic identification of different climate variables needed for the forecasting process (temperature, irradiance, wind speed, etc)
- Better treatment of historical profiles used in the forecasting process (correction of holiday periods, exceptional events, etc.)
- Split of the load forecast into temperature-dependent and temperature-independent components.
    - The final load profiles are adjusted, taking into account added consumption from heat pumps and electric vehicle charging.
    - The forecasts also consider the interdependencies of historical temperatures of each climate year and historical load patterns.

Elia has chosen to implement this new method for the first time in the 2019 Adequacy and Flexibility study. This makes it possible to determine the volume of strategic reserves in order to be more consistent with the methods developed at European level.

8.1.1.4 'Monte Carlo' sampling and composition of climatic years

The variables discussed in section 8.1.1.1 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 8.16).

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.

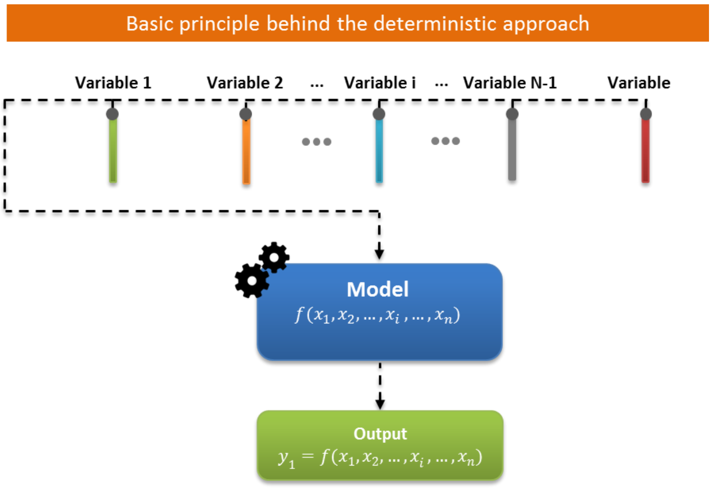


Figure 8.16

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 **error** for the results arising from the 'Monte Carlo' method decreases as $\mathbf{1/\sqrt{N}}$. 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, see section 8.1.2.1). Figure 8.17 shows a random sample for p independent variables, yielding N different future states.

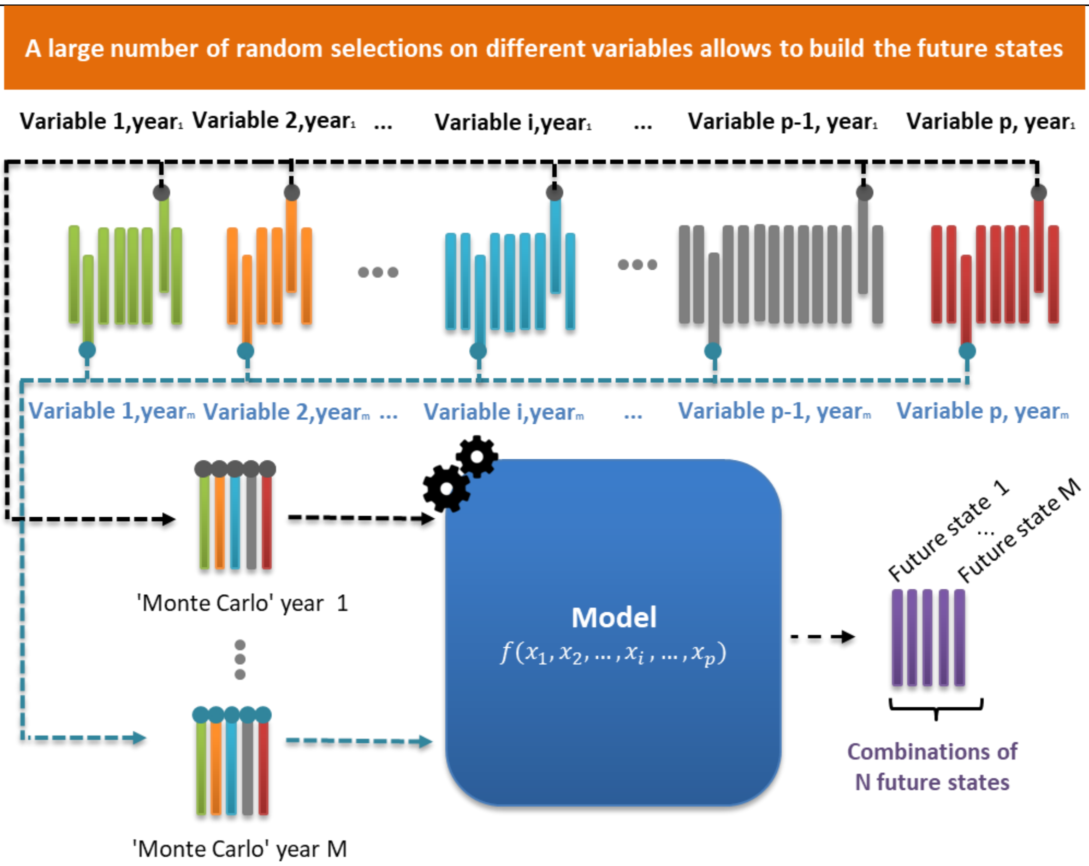


Figure 8.17

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 amount 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 0 for Belgium and Chapter 4 for its neighbouring countries.
The **key input data** for each country are:

- the hourly 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 hourly 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 8.18) and also enables the pumped-storage power plants and hydroelectric reservoirs to be appropriately modelled (see section 8.1.1.2.4).
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.

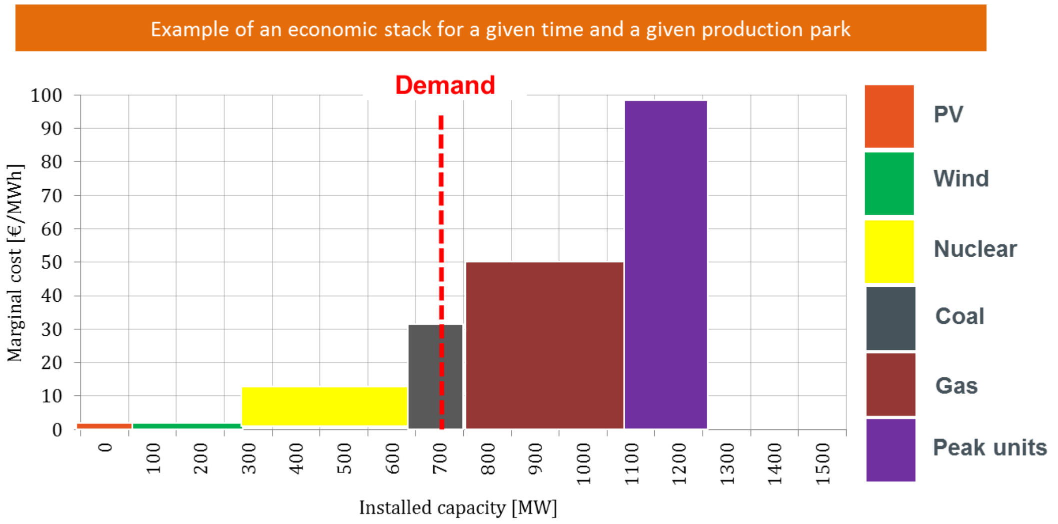


Figure 8.18

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[30], 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 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 8.1.1.4). The main process behind ANTARES is summarised in Figure 8.19 [12].

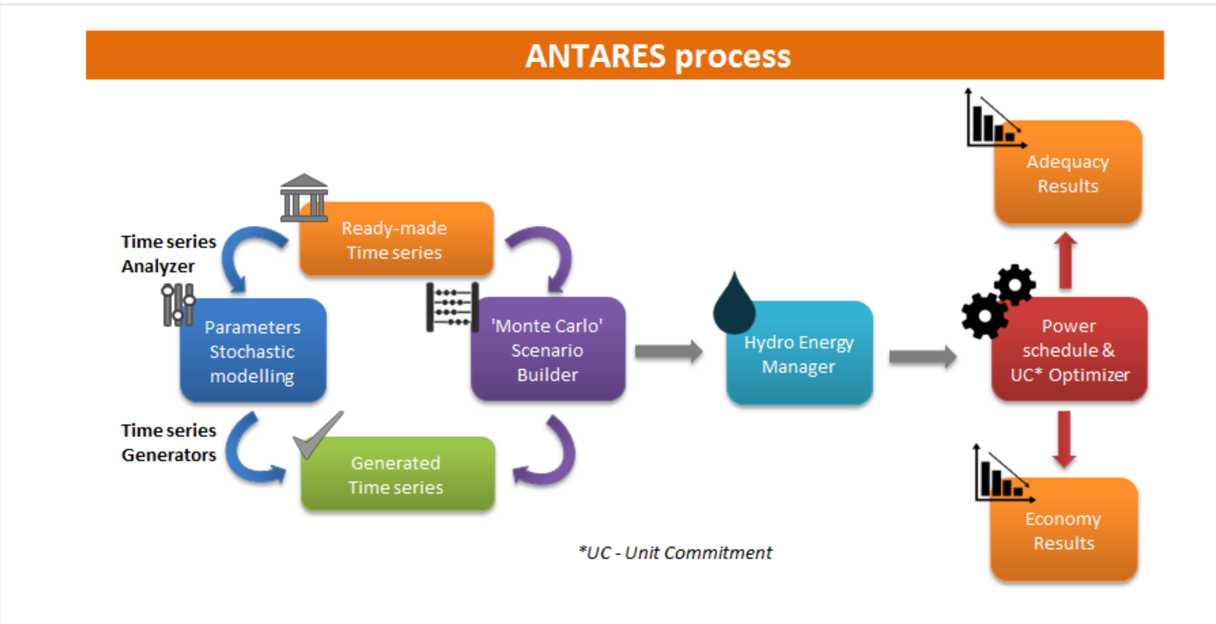


Figure 8.19

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

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

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 8.20). The number of time series for each parameter is usually between 10 to 100 and can be increased if necessary.

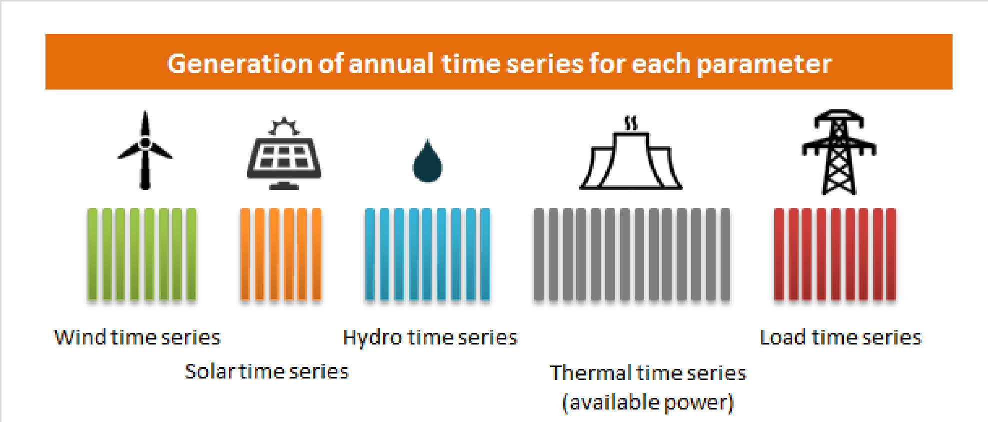


Figure 8.20

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 8.21.

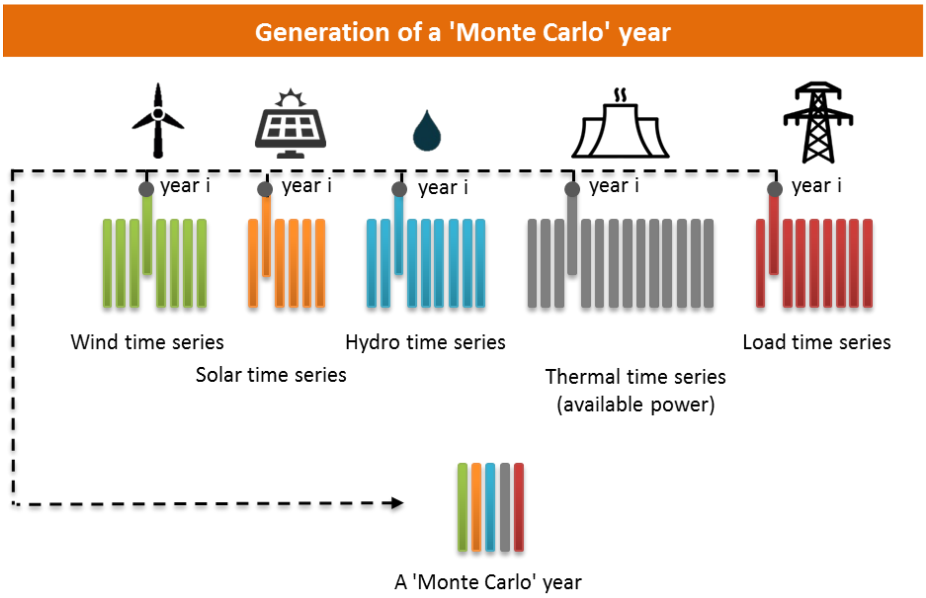


Figure 8.21

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 **8.1.1.4.**, 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 [15].

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) [12]. 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 published in 2015 [61], and the next version which is expected for publication on January 2018;
- the e-Highway2050 study [19];

- ENTSO-E's TYNDP [31] [20] and MAF [16];
- RTE French Generation Adequacy Reports [18].

•

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 [12].

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;

[31] TYNDP: Ten Year Network Development Plan

- 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[32] 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 8.22.

- The maximum amount of activations 'MAX' is used to determine the maximum number of activations during the winter period and is equal to **19**.
- The 'MAX' LOLE(h) is used for the cumulative maximum duration in hours of the annual delivery and is equal to **97 hours.**

[32] 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.

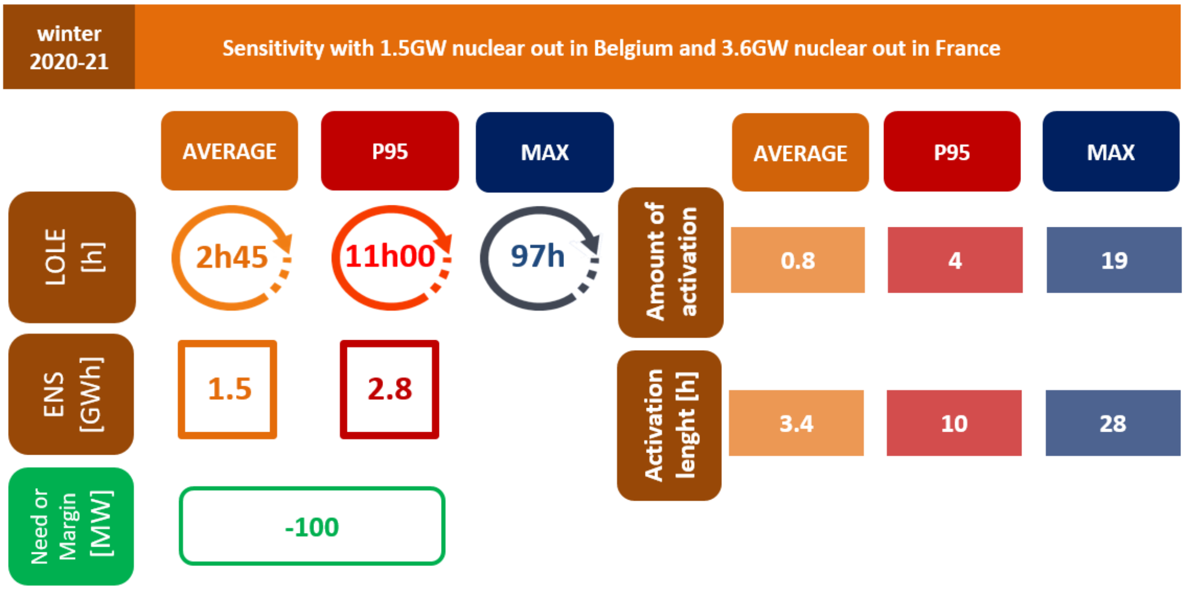


Figure 8.22

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 8.23.

- $\#Act_{cold}$: 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**.
- $\#Act_{hot}$: 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 **0**.
- $Act_{duration}$: 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**.

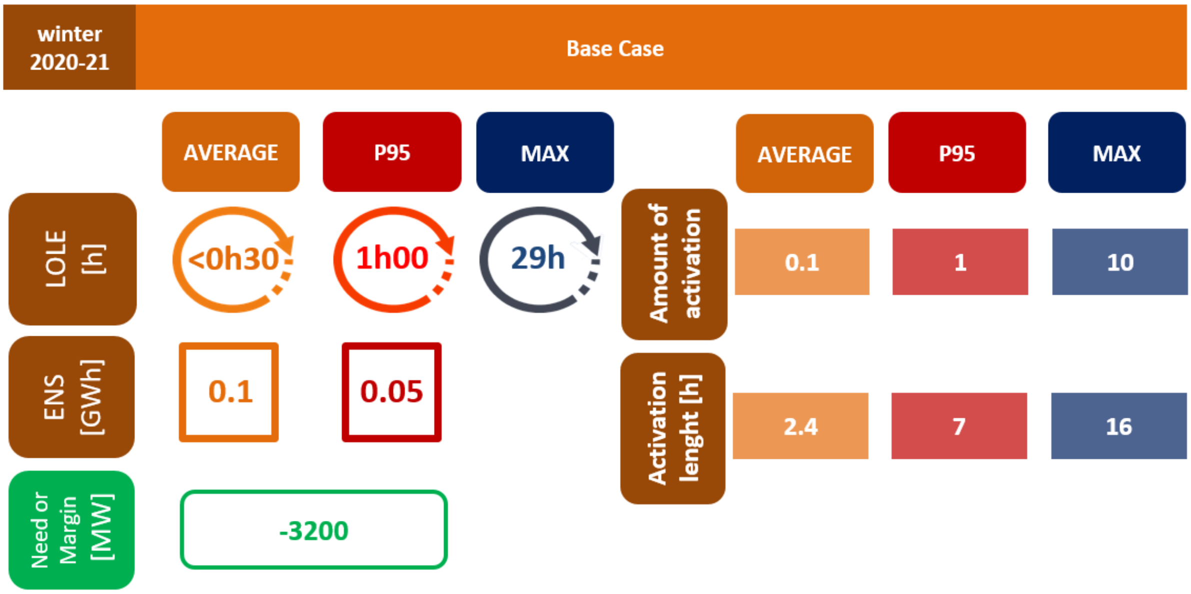


Figure 8.23

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 8.24) in the 'Sensitivity with 1.5 GW nuclear out in BE and 3.6 GW out in FR' scenario (Figure 8.22).

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.

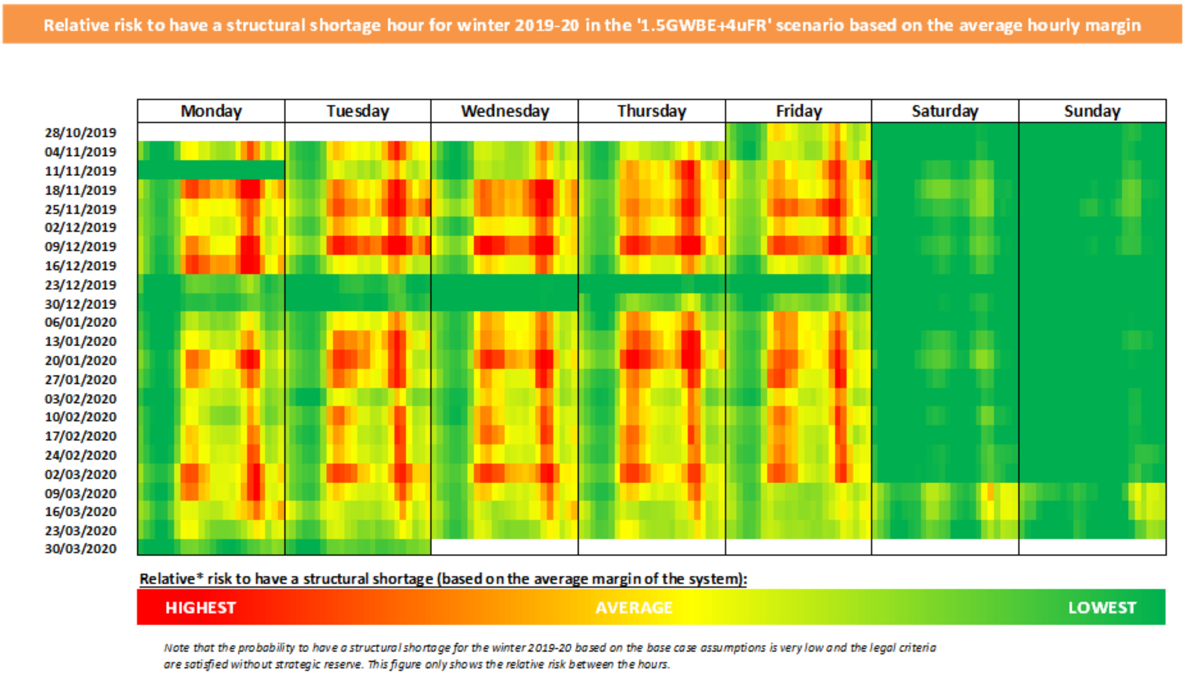


Figure 8.24

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.

8.2.1 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[33]) 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

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

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.

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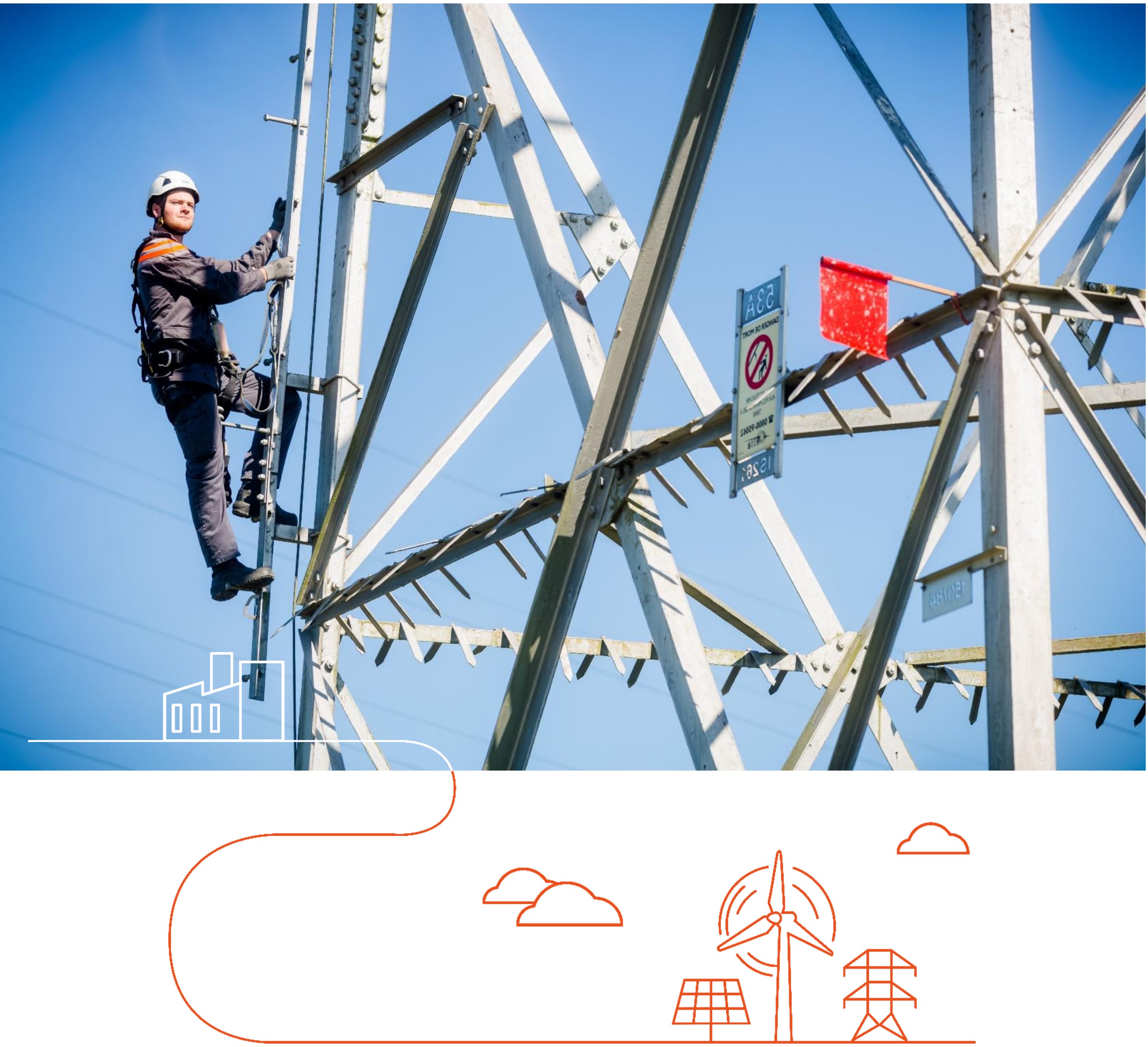
[33] SGR: strategic generation reserve

For this calculation, the 'Sensitivity with 1.5 GW nuclear out in BE and 3.6 GW out in FR' scenario (Figure 8.24), 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[34]**
Poffer ≤ 200 MW	N.A.
200 MW < Poffer ≤ 400 MW	N.A.
400 MW < Poffer ≤ 600 MW	N.A.
600 MW < Poffer	N.A.

[34] A calculation of the equivalence factor will be performed, should the volume of SR be revised by the Minister before 1 September 2019, and should the revised volume in this case be higher than 'zero' MW.

9. Abbreviations



aFRR: automatic frequency-restoration reserve

AMR: adjustment for minimum RAM

ANTARES: a new tool for adequacy reporting of electric systems

ARP: access responsible party

ASN: Nuclear Safety Agency

BRP: balance responsible party

CAGR: compound annual growth rate

CASC: capacity-allocating service company

CCG: CWE Consultative Group

CCGT: combined-cycle gas turbine

CEER: Council of European Energy Regulators

CfD: contracts for difference

CHP: combined heat and power

CIPU: contract for the injection of production units

CM: capacity mechanism

CNEC: critical network element and contingency

Coreso: Coordination of Electricity System Operators

CPB: Dutch Bureau for Economic Policy Analysis

CPF: carbon price floor

CREG: Commission for Electricity and Gas Regulation

CRM: capacity remuneration mechanism

CWE: Central West Europe

DA: day-ahead

DG: Directorate-General

DSO: distribution system operator

DSR: demand side response

ECN: Energy Research Centre of the Netherlands

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

FANC: Federal Agency for Nuclear Control

FB: flow-based

FBMC: flow-based market coupling

FCR: frequency containment reserve

FES: future energy scenario

FOR: forced outage rate

FPS: Federal Public Service

FRP: flexibility-requesting party

FRR: frequency restoration reserve

GDP: gross domestic product

GT: gas turbine

GU: grid user

HVDC: high-voltage direct current

IA: impact assessment

IHS CERA: Information Handling Services Cambridge Energy Research Associates

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

MR: market response

NCDC: National Climatic Data Center

NEV: Nationale EnergieVerkenning (Dutch National Energy Report)

NTC: net transfer capacity

OCGT: open-cycle gas turbine

OTC: over-the-counter

PBL: Dutch Environmental Assessment Agency

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)

SBR: supplemental balancing reserves

SDR: strategic demand reserve

SGR: strategic generation reserve

SO&AF: scenario outlook and adequacy forecast

SPAIC: standardised procedure for assessing the impact of changes

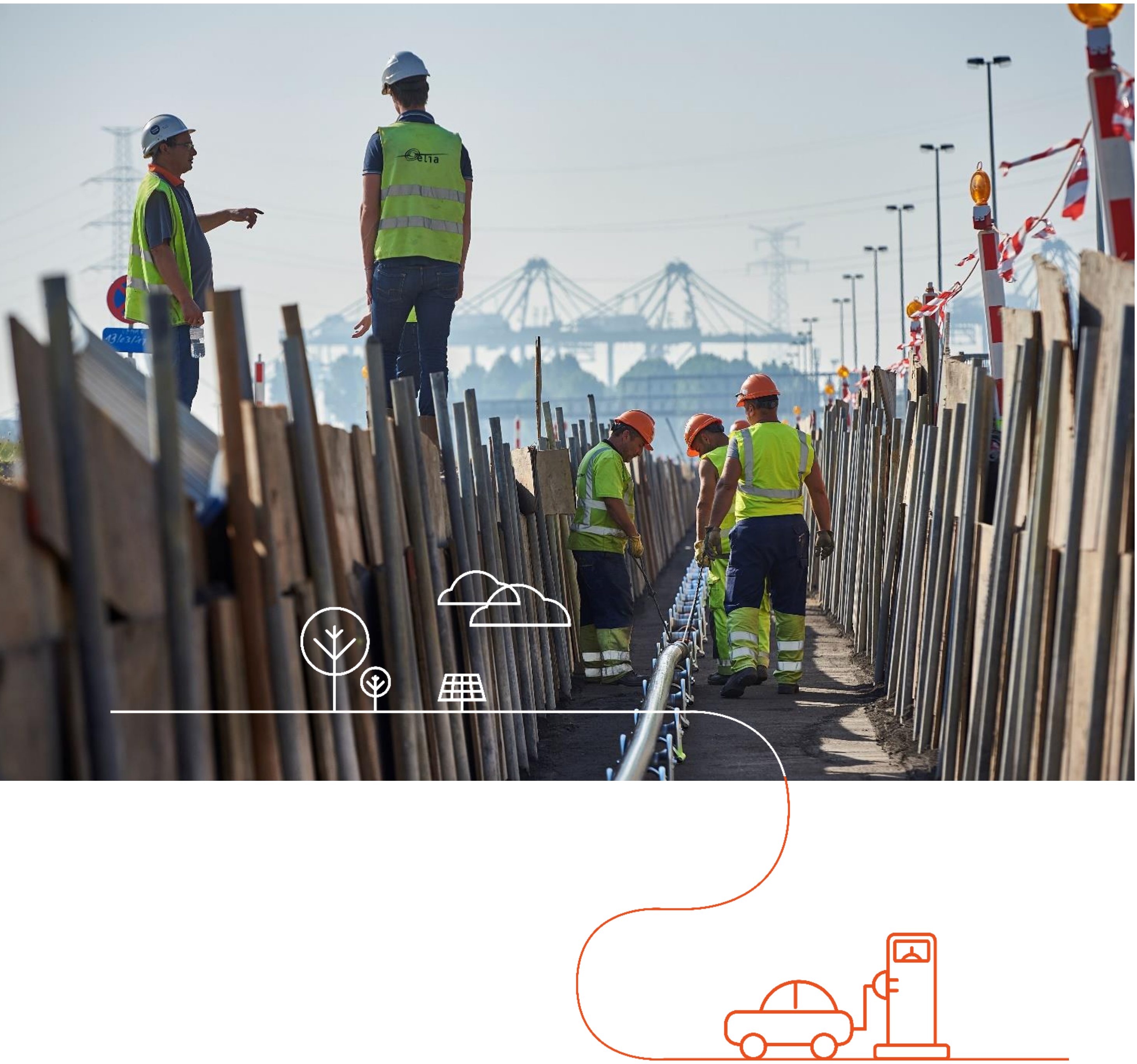
SR: strategic reserve

TSO: transmission system operator

TYNDP: ten-year network development plan

UC: unit commitment

10. Sources



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