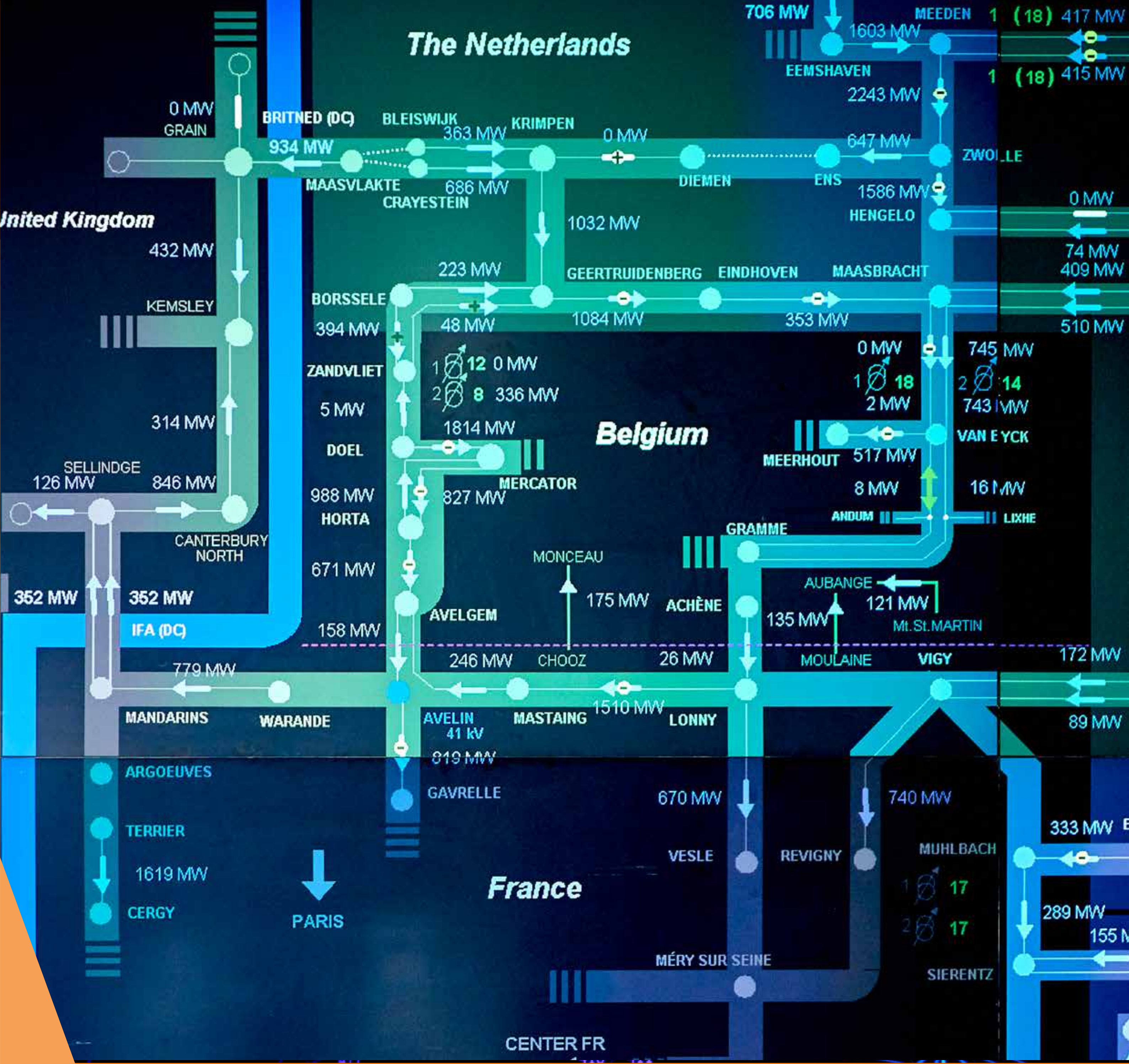

Adequacy and flexibility study for Belgium 2020 - 2030

| Elia Group

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It is still five minutes to midnight

Dear Reader,

Belgium is facing huge energy supply challenges in the near future. Its nuclear exit legislation means that by 2025 about half of the country's current electricity generation capacity will disappear. Moreover, the nuclear phase-out is happening against the more general backdrop of the energy transition taking place across Europe.

As the operator of Belgium's high-voltage grid, Elia ensures that the lights stay on. This remit means we also support the federal government in meeting its responsibility to maintain the country's security of supply. In this context, Elia published studies in 2016 and 2017 pointing to the impact of the major changes in the Belgian energy system and the measures required to prepare for them in time. This latest report follows on from these and describes the adequacy and flexibility needs in the period 2020-2030. These are both crucial pillars of a smoothly operating electricity system.

Our call to action applies more than ever. The replacement capacity required to cope with the nuclear exit in 2025 is up from 3.6 GW to around 3.9 GW.

Our most recent report on this subject from November 2017 (Electricity Scenarios for Belgium towards 2050) concluded that at least 3.6 GW of replacement capacity was needed in 2025 to cope with the impact of the nuclear exit and of developments in neighbouring countries. In the absence of sufficient investment, the free market would only be able to deal with this to some extent, making a support mechanism necessary to maintain security of supply.

We called on the federal government to produce a proposal which would have to be quickly coordinated with the European Union so that the capacity would be available in time. An important first step in this direction was taken in April 2019 with the amendment of the Electricity Act to establish the framework for introducing a capacity remuneration mechanism (CRM) in Belgium.

Given the ever-growing capacity need, it is crucial that the federal government's work on developing the planned CRM continues unabated so that Belgium has a robust safety net to maintain security of supply.

A year and a half later, we see in this new study that our call to action applies more than ever. The conclusions from our previous study have been confirmed and even reinforced insofar as the need for replacement capacity has gone up further from 3.6 GW to around 3.9 GW. This is mainly due to the accelerated coal phase out a number of European countries are now planning. This will make it harder for Belgium to import electricity from neighbouring countries when it has shortages.

Given the ever-growing capacity need, it is crucial that the federal government's work on developing the planned CRM continues unabated so that Belgium has a robust safety net to maintain security of supply at all times.

Next to preparing for a CRM, it is equally important to continue focusing on energy efficiency. In addition, the accelerated development of renewable energy sources will also bring a further positive contribution to the Paris climate agreements and a limited contribution to security of supply.

The coal phase out in neighbouring countries is making this even more pressing. As a result, between 2022 and 2025 additional capacity of more than 1 GW will be needed, requiring further measures to be taken.

This means that the work in this regard is far from over, all the more so because of the additional shortage indicated in this report. If Germany implements its coal exit commission's proposals, Belgium will be able to import less electricity as of winter 2022-2023, potentially resulting in a capacity shortage of more than 1 GW, which the market cannot necessarily be expected to offset. Therefore, further deliberations are needed, requiring additional consultation with the authorities and the regulator, to bridge the period between 2022 and the nuclear exit in 2025. Moreover, 2022-2025 coincides with the nuclear phase-out: Doel 3 will shut down in October 2022, followed by Tihange 2 in February 2023 and Belgium's other five nuclear reactors between February and December 2025.

Each scenario requires appropriate measures. There will be a need for upgrades to reactors whose operating licences are being renewed, with order times and periods of unavailability running into the winter months, which already promises to cause difficulties.

Elia plays an exclusively policy-support role in the energy debate. However, we repeat our call to action, given our observation of the increasing urgency of the situation and the fact that the power grid is a key pillar of Belgium's prosperity.

We also note that the nuclear exit as provided for by law is still a matter of debate and point out that the alternative scenario of a more gradual nuclear exit (e.g. renewal for Doel 4 and Tihange 3) would also have a significant impact. Even then, a considerable replacement capacity would still be necessary. Furthermore, there will be a need for upgrades to reactors whose operating licences are being renewed, with order times and periods of unavailability running into the winter months, which already promises to cause difficulties.

This means that each scenario requires appropriate measures and there must be clarity soon about the consequences and the action to be taken. Therefore, just as important as providing replacement capacity is the need for discussions to start soon with the nuclear power plants' owners.

Nor is that the end of it. Once the measures to support the nuclear exit have been taken, further efforts will be needed to pursue the process of meeting the climate objectives. This cannot happen without a long-term vision – a strategy that outlines the process and is adjusted along the way so that the goals can be achieved together.

In short, we ask the caretaker Belgian government and the next federal government to make the above needs an absolute priority. It is up to our policymakers to ensure that Belgium always has the necessary resources to be able to maintain security of supply at all times. Despite the efforts of the past year, at the time of writing we are not yet ready for any scenario. It is still five minutes to midnight. To ignore this from now on would be culpable negligence.

Chris Peeters – CEO of Elia

Executive summary

Call to Action 2.0

With the publication of this report on adequacy and flexibility needs in the period 2020-2030, we are launching a new call to action for the Belgian authorities. Attention must continue to focus as a priority on the impact of the nuclear exit provided for by law and the changing context of the energy transition in Europe if we want to be able to maintain security of supply in Belgium.

Additional capacity is needed to avert the risk of electricity shortages and even serious supply problems in the winter months. This study confirms and even reinforces the conclusions of other reports.

>1 GW of additional capacity required between 2022 and 2025

A key new development emerging in this study is the accelerated coal phase out in Belgium's neighbouring countries. In particular if Germany implemented its coal exit commission's plans, this would seriously hit Belgium's import options in winter, and would do so in the near future. As a result, in the period 2022-2025 we would need even more additional capacity, amounting to more than 1 GW, requiring further measures to be taken.

3.9 GW of additional capacity as of 2025

With the accelerated coal phase out in neighbouring countries, we are also witnessing an increase in the additional capacity needed as of winter 2025-2026 to offset the shutdown of the last five nuclear reactors. Whereas this replacement capacity was 3.6 GW in 2017, it is now 3.9 GW.

This capacity will not just appear out of thin air. Based on the assumptions and calculations in this study, Elia still discerns insufficient investment.

For the sake of Belgian society, both the caretaker government and the next federal government absolutely must have all the resources they need in time to avoid a serious capacity crisis. This means that the efforts to establish a capacity remuneration mechanism (CRM) must continue unabated.

Approach

As provided for in the Belgian Electricity Act, this study has been prepared both in collaboration with the Federal Public Service (FPS) Economy and the Federal Planning Bureau and in consultation with the Commission for Electricity and Gas Regulation (CREG). Regular meetings and consultations have been held with these government agencies since November 2018.

In addition, a public consultation was held in January 2019 during which stakeholders were given the chance to learn about the working hypotheses used (data and scenarios). We received more than 100 comments and suggestions, for example about additional sensitivities. A wide range of scenarios were considered, including an extra 1 GW in market response, additional energy storage, 1 GW more from combined heat and power (CHP) plants, accelerated rollout of onshore and offshore wind farms and a partial nuclear extension. We took all the requests into account.

This study only quantifies the adequacy and flexibility needs for the period 2020-2030. In this report, we do not calculate the volume involved in the future capacity remuneration mechanism. Those calculations will be part of a subsequent process. In November 2019, Elia will also publish a further report on the possible need for strategic reserves for winter 2020-2021 and the two years after that.

This study is fully in line with the current legal and regulatory framework and already abides by the spirit of the new EU legislation that will soon come into force (the Clean Energy for All Europeans package). The hypotheses drew on the draft Belgian National Energy and Climate Plan 2021-2030 and the Vision Paper for an Interfederal Energy Pact for Belgium.

What are adequacy and flexibility?

In this study, Elia quantifies Belgium's anticipated adequacy and flexibility needs for the period 2020 2030. 'Adequacy' and 'flexibility' are two crucial pillars of a smoothly operating electricity system and help maintain security of supply.

An electricity system is 'adequate' if there is sufficient capacity to meet the relevant needs (via generation, imports, storage, demand-side management and so on). Flexibility relates to the ability to cope with fluctuations between production and consumption due to the increasing volatility of generation.

EXECUTIVE SUMMARY

MAIN CONCLUSIONS

1 IF WE WANT THE NUCLEAR EXIT IN BELGIUM TO TAKE PLACE IN AN ORDERLY WAY, A REPLACEMENT CAPACITY OF AROUND 3.9 GW WILL BE NEEDED AS OF 2025.

As of the nuclear exit (winter 2025-2026) we will see a systematic need for new capacity of some 3.9 GW. This takes into consideration uncertainties in Belgium's neighbouring countries (around 1.5 GW) over which Belgium has no control, such as the reduced availability of generation or interconnections.

This study confirms and reinforces previous findings on the replacement capacity required for the nuclear exit in late 2025. This capacity can be covered by any technology but is necessary to be able to maintain security of supply in Belgium. Whereas in its study from late 2017 (Electricity Scenarios for Belgium towards 2050) Elia mentioned the need for 3.6 GW of replacement capacity, this is now quantified as 3.9 GW. The urgency is growing due to the accelerated coal exit in Belgium's neighbouring countries, especially in Germany.

Even if the nuclear exit is partly reversed by, for example, keeping two reactors (2 GW) open for longer, there will still be a systematic need for new capacity.

The structural capacity requirements will remain at a stable level between 2025 and 2030. Within this time frame, the gradual decommissioning of conventional generation plants in Europe will be balanced out by the mass arrival of renewable energy production on the scene. The speed of this transition and its exact timing may adversely affect capacity requirements if it is not planned properly.

2 THE EARLY COAL PHASE OUT IN NEIGHBOURING COUNTRIES MEANS THAT WE WILL NEED UP TO >1 GW EXTRA IN ADDITIONAL CAPACITY IN THE PERIOD 2022-2025.

Due to the accelerated coal phase out in neighbouring countries, the additional capacity Belgium will require for the winters 2022-2023, 2023-2024 and 2024-2025 has increased. This new development means that even before the nuclear exit in late 2025, yet more additional capacity exceeding 1 GW will be needed, requiring further measures to be taken.

In the next 10 years, coal-fired and nuclear power plants with a total capacity of around 100 GW will be shut down in Europe, above all in Western Europe. Since the publication of the previous adequacy and flexibility study in 2016, announcements of early and additional shutdowns mean a capacity reduction of 26 GW. The accelerated coal exit in neighbouring countries (the Netherlands, the United Kingdom, Italy, France and especially Germany) will have an adverse impact on our ability to import electricity in the winter months.

Additional measures will be required as of winter 2022-2023 to maintain security of supply in this changing context, given that the current strategy reserves mechanism has only been approved until winter 2021-2022. The additional measures will be needed to bridge the period 2022-2025. Only then will the general capacity remuneration mechanism (CRM), with the support this will give the market, be introduced.

3 FAILING ANY INTERVENTION (IN THE FORM OF A CRM), THERE WILL BE INSUFFICIENT INVESTMENT TO ENSURE THAT A FULL 3.9 GW OF NEW REPLACEMENT CAPACITY WILL BE AVAILABLE IN TIME TO COPE WITH THE NUCLEAR EXIT.

This study confirms the need for a systematic intervention (even if there is a partial nuclear renewal) that provides the investment required to ensure that the full replacement capacity is available in time. This must be tackled fast. The formal European Commission notification procedure must be launched by the end of December 2019 at the latest. Therefore, Elia asks the caretaker Belgian government and the next federal government to make this a priority so that the planned CRM offers market security for the near future. The CRM is a crucial safety net for risks of serious supply problems or electricity shortages.

The current support system involving temporary bookings of strategic reserves (off the market and on demand) is ill-suited to coping with the systematic capacity shortage arising from the nuclear exit. The strategic reserves generally keep uncompetitive power plants operating on the market for a short period but do not provide an incentive for new construction.

If we want to systematically ensure security of supply in Belgium after the nuclear exit, then we still consider that a market-wide CRM, complementing the energy market (Energy-Only Market) with a real capacity market, would be an effective solution. This mechanism must be technology-neutral (production, storage, demand management and so on), cost as little as possible and be in line with EU legislation.

An important first step was taken in April 2019 with the amendment of the Electricity Act to establish the framework for introducing such a capacity remuneration mechanism. This work, including the preparation of implementing decrees and the relevant detailed market rules, must continue unabated so that the formal European Commission notification procedure can be launched by the end of December 2019. The Commission will then investigate whether the mechanism distorts the market.

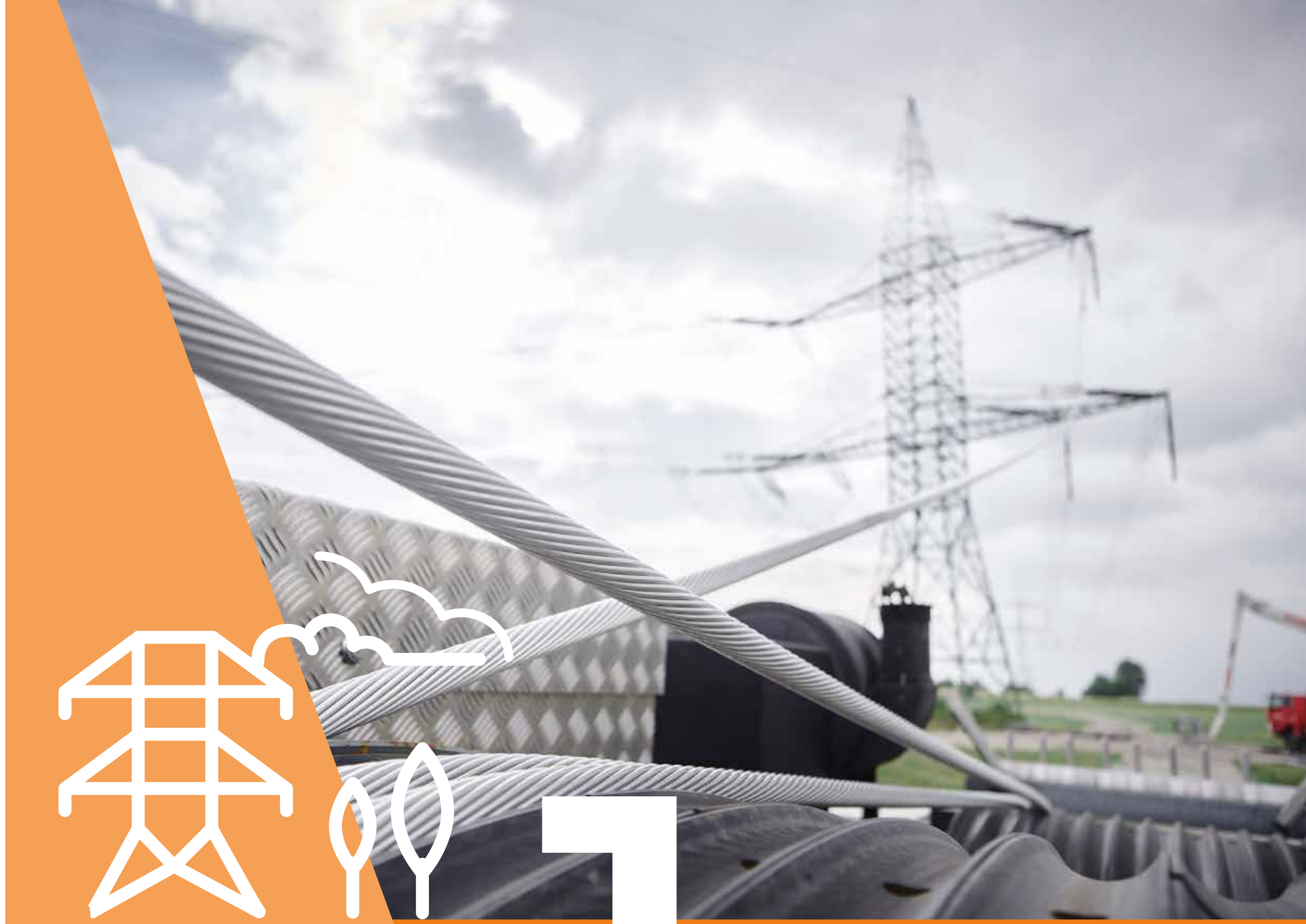
Next to preparing for a CRM, it is equally important to continue focusing on energy efficiency. In addition, the accelerated development of renewable energy sources will also bring a further positive contribution to the Paris climate agreements and a limited contribution to security of supply.

4 IN THE YEARS LEADING UP TO 2030, THE AVAILABLE FLEXIBILITY RESOURCES WILL BE ABLE TO COPE WITH THE INCREASING VARIABILITY THAT RENEWABLE ENERGY PRODUCTION INTRODUCES INTO THE ELECTRICITY SYSTEM.

Despite the additional challenges an increasing volume of renewable energy production will pose for system management, Elia expects that sufficient flexibility resources will be available to cope with the increased fluctuations between injections and offtake resulting from more volatile means of generation. This of course depends on there being no problems with the adequacy of the electricity system.

Although there will be enough flexible capacity in the system, care must be taken to ensure that this capacity is actually operationally available at all times in the period 2020-2030. This means there must be sufficient flexible resources in place that can be kept available both by the market and by Elia. This is the only way to cope with unexpected fluctuations in injections and offtake.

This study also confirms that new technologies covering areas such as storage and demand response will increasingly help cope with fluctuations in a renewable electricity system. Elia encourages this, actively contributing to proposals supporting this trend. In this light, Elia was one of those behind the launch of the Internet of Energy (IO.Energy) project in late 2018. After a pilot phase that is currently in preparation, the elimination of thresholds and the use of more fine-grained time-dependent price signals will ensure that even at the lower voltage levels, flexibility can play an optimal role in market operations.



1 Introduction

1.1. Context and objectives of this report

1.1.1. Context of the study

The European electricity system is profoundly and rapidly reshaping, as it is facing unprecedented changes and needs to adapt to meet major challenges - integrating high volumes of variable renewables, increasing decentralisation, digitalisation, the appearance of new players, the phase out of some conventional generation sources - whilst safeguarding security of supply, the balance of the system and ensuring competitiveness with neighbouring countries.

As the Transmission System Operator (TSO) for the Belgian electricity system, Elia will play a central role in these developments. In this respect, Elia is actively working to support the energy transition through innovation and continuous improvement in its role of developing and maintaining the transmission infrastructure, operating the system and facilitating the market.

In addition, Elia is encouraged by the Belgian federal government to take action by fulfilling a role as expert, facilitator and coordinator in the context of the debate about security of supply. This has also led to a modification of the Federal Electricity law of 29 April 1999 on the organisation of the electricity market ('Electricity Law'). More specifically, **Elia has been assigned the biennial task to perform an adequacy and flexibility analysis for the Belgian electricity system with an outlook for the next 10 years.**

The two central aspects of this study, adequacy on the one hand and flexibility on the other are both crucial aspects for the well functioning of the electricity system. Adequacy ensures that the sum of available and expected capacity, including imports, are at any time sufficient to meet the demand. The flexibility assessment investigates the extent to which this capacity disposes of the right technical characteristics to cope with future (un)expected variations of generation (in particular driven by renewable generation) and demand.

This study is the first edition following the new legal assignment for Elia and covers the time period from 2020 to 2030.

1.1.2. Legal framework

The Belgian framework: The Belgian Electricity Law

This study is based on article 7bis, §4bis of the Electricity Law, which states that (own translation):

Art.7bis, §4bis (study framework)

"No later than 30 June of each biennial period, the system operator shall carry out an analysis of the needs of the Belgian electricity system in terms of the country's adequacy and flexibility for the next ten years.

The basic assumptions and scenarios, as well as the methodology used for this analysis shall be determined by the system operator in collaboration with the Directorate General for Energy and the Federal Planning Bureau and in concertation with the Regulator."

In §5 of the same article, it is foreseen that the analysis should be submitted to the Minister (of Energy) and the Directorate General for Energy of the Federal Public Service of Economy ('FPS Economy'). In addition it must be published on the websites of the Transmission System Operator and the FPS Economy.

/ INTRODUCTION

Art.2 52°-53° & Art.7 bis, §2 (reliability standard)

Eventhough this study is not a calculation to determine the volume for the strategic reserves (for which the next yearly study is foreseen in November 2019), the reliability standard in terms of adequacy that is to be ensured in the strategic reserve framework is assumed to be equally valid for this analysis. This is **the only adequacy reliability standard defined today for Belgium**. This also ensures coherency with all the previous adequacy assessments. In the current Electricity Law a two-part loss of load expectation (LOLE) criteria (see Figure 1-1) is described as the reliability standard, i.e. the level of security of supply that needs to be achieved for Belgium:

- ***LOLE:*** *A statistical calculation used as a basis for determining the anticipated number of hours during which, even taking into account interconnectors, the generation resources available to the Belgian electricity grid will be unable to cover the load for a statistically normal year. (art.2, 52° Electricity Law – own translation)*
- ***LOLE95:*** *A statistical calculation used as a basis for determining the anticipated number of hours during which, even taking into account interconnectors, the generation resources available to the Belgian electricity grid will be unable to cover the load for a statistically abnormal year. (art.2, 53° Electricity Law – own translation)*

ADEQUACY CRITERIA [FIGURE 1-1]

LOLE < 3 hours
LOLE95 < 20 hours

The model Elia uses for the probabilistic assessment enables both indicators to be calculated. Additional information about how to interprete these criteria can be found in Appendix A.

There is at this moment **no legally determined standard for flexibility**, but obviously the analysis and methodology are based on identifying the needs in order to keep a system in balance at all times, which is one of the core tasks of the TSO in accordance with article 8 of the Electricity Law. In addition, Balance Responsible Parties (BRPs) are in first instance expected to present a day-ahead portfolio in balance.

The lack of legally determined standard for this flexibility analysis is not to be confused with the minimum criteria that Elia uses for its dimensioning of reserve capacity on Frequency Restoration Reserves (FRR) when covering Load Frequency Control (LFC) block imbalances. This is currently set to cover at least 99.0% of expected LFC block imbalances. This criteria does not alleviate the requirement of the system (and the market) to be in balance at all times.

The European framework

There is currently little European regulation concerning adequacy and flexibility methods. In article 8 of Regulation 714/2009 however, the tasks of ENTSO-E are described, among which figure the annual summer and winter generation adequacy outlooks and the Mid-Term Adequacy Forecast ('MAF'), to which Elia actively participates.

As from 1 January 2020, a new Regulation of the European Parliament and of the Council on the internal market for electricity (recast) will be applicable. This Regulation is part of the legislative package on which the European institutions have been working on for the last years, better known as the 'Clean Energy for all Europeans Package' (CEP).

In this Regulation, Chapter IV is dealing with Resource Adequacy. It contains 8 articles (article 20-27) and stipulates in article 24 some modalities for the National Resource Adequacy Assessment.

As these stipulations are not yet applicable and, moreover, as the foreseen minimum timings for submission and approval of the in the Regulation foreseen methodologies (particularly the methodology on the European resource adequacy assessment and the reliability standard (Art. 23 & 25)) will need at least nine months after entry into force, **there is to date no methodology following the Regulation that should be used as a basis for this study**. The former notwithsthanding, Elia has deployed a lot of care to ensure that **this 10-year adequacy and flexibility study is to a maximum extent in line with both the spirit and the modalities** that are foreseen in article 24 (national resource adequacy assessment) and the more elaborated principles as stipulated in article 23 (European resource adequacy assessment), in particular art.23(5) (b) to (m) of the upcoming Regulation.

Indeed, points (b) to (g), (l) and (m) are addressed in Chapter 2 where the details on scenario framework and data assumptions are given. Points (h) and (i) are addressed in Chapter 3 where the methodology is explained. Point (j) and (k) are tackled in Chapter 4 where results are detailed and explained.

The same reasoning applies to reliability standards. Article 25 of the Electricity Regulation refers to modalities on that level. However, this provision is not applicable yet. Moreover it is not implemented (i.a. with a methodology to determine the reliability standards). Hence, the present study is based on the reliability standards that are in force in Belgium, as stipulated in the Electricity Act. Notwithstanding this, the study does take as much as possible into account the Electricity Regulation. Consequently, it already pro-actively refers to both the LOLE hours and the Expected Energy Not Served (EENS), two standards referred to in the above mentioned Article 25 of the Electricity Regulation.

Article 23 European resource adequacy assessments

[…]

5. *The European resource adequacy assessment shall be based on a transparent methodology which shall ensure that the assessment:*

(a) […]

(b) is based on appropriate central reference scenarios of projected demand and supply including an economic assessment of the likelihood of retirement, mothballing, new-build of generation assets and measures to reach energy efficiency and electricity interconnection targets and appropriate sensitivities on extreme weather events, hydrological conditions, wholesale prices and carbon price developments;

(c) contains separate scenarios reflecting the differing likelihoods of the occurrence of resource adequacy concerns which the different types of capacity mechanisms are designed to address;

(d) appropriately takes account of the contribution of all resources including existing and future possibilities for generation, energy storage, sectoral integration, demand response, and import and export and their contribution to flexible system operation;

(e) anticipates the likely impact of the measures referred to in Article 20(3);

(f) includes variants without existing or planned capacity mechanisms and, where applicable, variants with such mechanisms;

(g) is based on a market model using the flow-based approach, where applicable;

(h) applies probabilistic calculations;

(i) applies a single modelling tool;

(j) includes at least the following indicators referred to in Article 25:

- *"expected energy not served", and*
- *"loss of load expectation";*

(k) identifies the sources of possible resource adequacy concerns, in particular whether it is a network constraint, a resource constraint, or both;

(l) takes into account real network development;

(m) ensures that the national characteristics of generation, demand flexibility and energy storage, the availability of primary resources and the level of interconnection are properly taken into consideration.

Article 24 National resource adequacy assessments

1. *National resource adequacy assessments shall have a regional scope and shall be based on the methodology referred to in Article 23(3) in particular in points (b) to (m) of Article 23(5). National resource adequacy assessments shall contain the reference central scenarios as referred to in point (b) of Article 23(5).*

National resource adequacy assessments may take into account additional sensitivities to those referred to in point (b) of Article 23(5). In such cases, national resource adequacy assessments may:

(a) make assumptions taking into account the particularities of national electricity demand and supply;

(b) use tools and consistent recent data that are complementary to those used by the ENTSO for Electricity for the European resource adequacy assessment.

In addition, the national resource adequacy assessments, in assessing the contribution of capacity providers located in another Member State to the security of supply of the bidding zones that they cover, shall use the methodology as provided for in point (a) of Article 26(11).

2. *National resource adequacy assessments and, where applicable, the European resource adequacy assessment and the opinion of ACER pursuant to paragraph 3 shall be made publicly available.*

3. *Where the national resource adequacy assessment identifies an adequacy concern with regard to a bidding zone that was not identified in the European resource adequacy assessment, the national resource adequacy assessment shall include the reasons for the divergence between the two resource adequacy assessments, including details of the sensitivities used and the underlying assumptions. Member States shall publish that assessment and submit it to ACER.*

1.1.3. Overview of previous studies

In addition to this new biennial, 10-year adequacy and flexibility study, Elia already performs, individually or as a partner in other organisations, a multitude of adequacy studies.

First of all, in the framework of the **strategic reserves**, Elia performs a yearly analysis of the adequacy needs for the Belgian system for the upcoming winter period, and with an outlook for the next two winter periods. This analysis, assigned to Elia as per art. 7bis of the Electricity Law, is performed by November 15th of each year. All previous reports are available on the websites of Elia [ELI-1] and the FPS Economy [FPS-1].

In addition, at the request of the Federal Minister of Energy, Mrs Marie-Christine Marghem, **a study on the adequacy and flexibility needs of the Belgian electricity system was performed by Elia in 2016** [ELI-2][ELI-6]. This study was realised by Elia in cooperation with the Cabinet of the Minister and the FPS Economy. An addendum to this study (published in September 2016) was carried out following a public consultation organised by the FPS Economy [FPS-2]:.

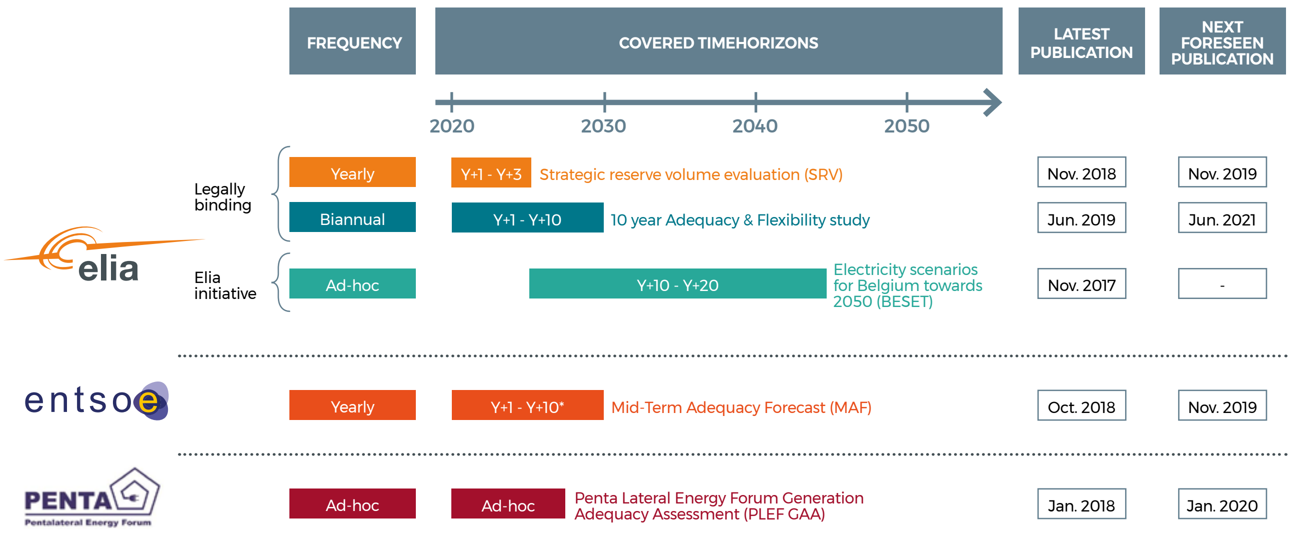
This 2016 study on adequacy included a 10-year ahead 'flexibility analysis', focusing on determining the reserve capacity needs to be foreseen by the Transmission System Operator. These needs were calculated based on a statistical method in which historical system imbalances and prediction errors of renewable generation were extrapolated towards the future. The calculated reserve capacity needs were thereafter taken into account in the adequacy assessment.

In 2017, Elia took the voluntary initiative to perform a study with a long-term horizon, i.e. up to 2050. **The study '*Electricity scenarios for Belgium towards 2050 – Elia's quantified study on the energy transition in 2030 and 2040*'** was published in November 2017 [ELI-3]. This study was designed to complement existing studies on 2050 trajectories, with a focus on the Belgian electricity sector within the European landscape. By outlining electricity scenarios for 2030 and 2040 on the path towards 2050, the study aimed to provide a solid basis for the choices that Belgian authorities have to make concerning the development of the electricity sector in the three dimensions of the 'Energy Trilemma'.

In addition, Elia also closely collaborates with its European colleagues of ENTSO-E to perform a yearly European adequacy analysis, called the **'Mid-term Adequacy Forecast (MAF)'**. This analysis also includes some elements related to system flexibility and can be considered as a European adequacy assessment which will further evolve into the European resource adequacy assessment as mentioned in the CEP. It is worth noting that all the previous releases of this study have always shown results in line with the Belgian national resource adequacy assessments. The MAF is subject to a vast public consultation process and all documentation is publicly available on the website of ENTSO-E [ENT-1]. The next release of this study is foreseen for November 2019 and will be based on the same data sources as used for the present study.

Finally, Elia also collaborates with the **Pentalateral Energy Forum** which occasionally performs additional adequacy assessments with a regional focus. The planning and scope of these studies are illustrated in Figure 1-2.

OVERVIEW OF NATIONAL, REGIONAL AND EUROPEAN ADEQUACY STUDIES [FIGURE 1-2]



* Although the latest edition of MAF 2019 will consider Y+1 and Y+5 only, the target model according to CEP is Y+1 and Y+10 with yearly resolution.

1.1.4. Overview of recent relevant political milestones

On December 24th, 2018, the Governance Regulation (EU) 2018/1999 on the Energy Union entered into force, which included, among other things, the obligation for all EU member states to submit a first draft of an integrated **National Energy and Climate Plan 2021-2030 (NECP)** to the European Commission by the end of 2018. Belgium fulfilled this obligation and submitted its draft NECP and all the relevant annexes to the European Commission on December 31st, 2018 [NEC-1].

A public consultation on the NECP was launched by the authorities on June 4th 2019 in accordance with Article 10 of the Governance Regulation. The objective is to submit a final NECP to the European Commission by December 31st, 2019 at the latest.

As the NECP covers a wide range of topics related to the federal, as well as to the regional levels of Belgium, a specific working group within the 'CONCERE/ENOVER' platform has been put in place. This working group consists of representatives of the climate and energy administrations of each region and of the federal level.

The draft NECP is thus considered as the most relevant and recent source of information from the authorities, in particular for the targets for renewable energy generation and the evolution of the demand.

Prior to the adoption of the NECP, the Federal and Regional governments concluded a note on the **vision of an interfederal energy pact for Belgium** [TOM-1]. This document contains useful values on several parameters not included in the NECP, in particular regarding market response and storage.

Both sources from the Belgian public authorities can thus be considered complementary and have accordingly been taken into account in this study. More information on the assumptions can be found in Chapter 2.

BOX 1: A CAPACITY REMUNERATION MECHANISM (CRM) FOR BELGIUM

On April 4th 2019 the Belgian Federal Parliament adopted a proposal of law, modifying the Electricity Law in order to anticipate the implementation of a Capacity Remuneration Mechanism in Belgium [DEK-1]. This framework law still needs to be further complemented with a number of Royal Decrees and working rules (detailed principles, parameters, methodologies, eligibility criteria, etc.).

By the end of 2019, this work should be finalised, after a vast stakeholder engagement process, so that the Belgian authorities can notify the capacity remuneration mechanism to the European Commission in order to respect the State Aid guidelines.

A committee of representatives of the CREG, the FPS Economy, Elia and the cabinet of Minister Marghem has been set-up to oversee the progress and to discuss all further details of the CRM. All these elements are consequently discussed with a wide range of market actors. The Elia Users' Group platform is used to centralise all these stakeholder interactions and all documentation (meeting minutes, participant lists, presentations, market parties' position papers, etc.) is publicly available and continuously kept up to date [ELI-4].

Once the mechanism has been approved by the European Commission, as a first formal step of the CRM, an adequacy and parameter report is foreseen towards the end of 2020. This report will be established according to a pre-defined methodology, after public consultation and several formal advices. This first step is then followed by a series of other decisions and milestones that should lead to the first auction (T-4) in 2021, to ensure the availability of the necessary capacity as from 1 November 2025 to guarantee the security of supply of Belgium.

Eventhough the Capacity Remuneration Mechanism and this study on adequacy and flexibility are closely linked, as they both deal with the adequacy of Belgium, it should be pointed out that this study is not the basis for the calibration of the parameters required in the framework of the CRM design or the calibration of the volumes to be procured in the future CRM auctions (as mentioned above).

The present study however does provide a very accurate and detailed view on the adequacy outlook for the next 10 years on the basis of a state-of-the-art methodology, which can serve as input for any future reflections on the matter, in particular to demonstrate the need for a Belgian CRM towards the European authorities.

1.2. Stakeholder involvement

As stipulated in the Electricity Law, the basic assumptions and scenarios, as well as the methodology used for this study should be determined by the transmission system operator *in collaboration* with the FPS Economy and the Federal Planning Bureau (FPB) and *in concertation* with the Regulator.

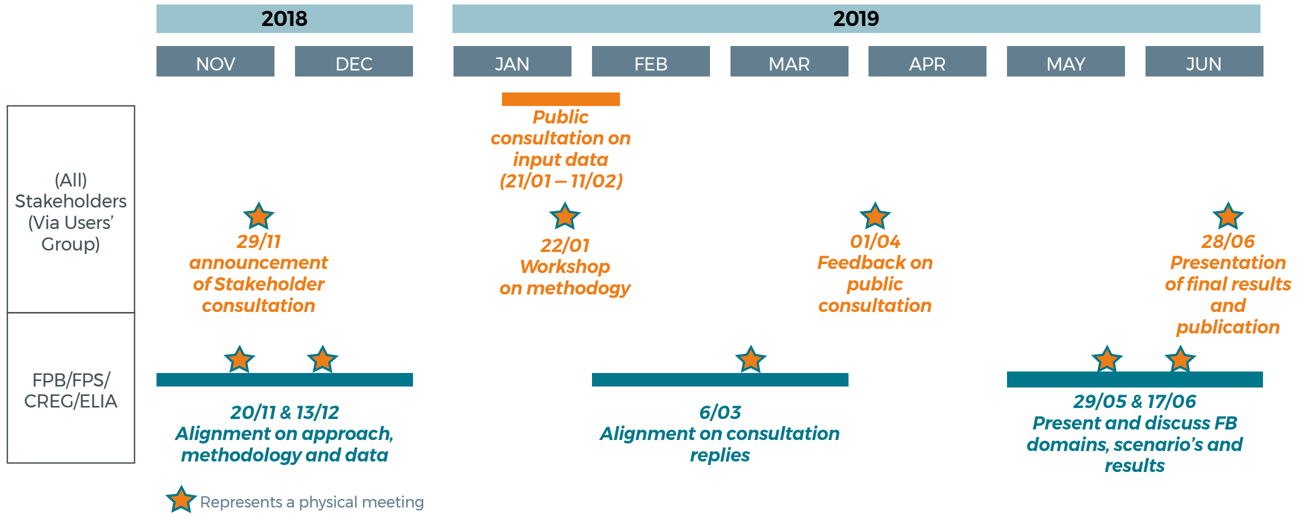
Right from the start, **no distinction was made between the involvement of the FPS Economy and the Federal Planning Bureau on the one hand, and the Regulator on the other hand.** Instead, a working group involving designated representatives of each institution was established to exchange information, present and discuss the approach, progress, results, etc. More concretely, prior to the publication of this report five extensive meetings have taken place: on November 20th 2018 (proposal approach, timing and methodology), December 13th 2018 (refinement methodology and assumptions prior to consultation), March 6th 2019 (modifications following public consultation), May 29th 2019 (first results, flow-based domains, scenarios and sensitivities) and June 17th (additional meeting on results and conclusions).

In addition, there have been a number of bilateral meetings with some members of the working group (e.g. explanation on the used model for adequacy and clarifications on the new methodology for the flexibility assessment) and regular e-mail exchanges have taken place. This constructive collaboration has significantly helped to improve the overall quality of the report and has contributed to shape the actual scope of the study.

Eventhough not formally instructed by the Electricity Law, on proposal of Elia, the working group supported the approach to engage actively with the market parties prior to the elaboration and publication of the study. In this respect, **a public consultation was organised on the input data to be used for this study**. The consultation aimed at receiving comments from the market on these data and on receiving any suggestion for sensitivity analyses on the CENTRAL scenario.

The consultation period was set from Monday 21th of January 2019 until Monday 11th of February 2019, was publicly announced on the Elia website and was discussed during a Task Force Implementing Strategic Reserves on January 22nd 2019. During this Task Force the methodologies of the flexibility and adequacy analysis were also presented. Specific attention was given to the methodology for the flexibility assessment as it is the first time that the methodology will be implemented. The adequacy methodology however further builds on previously used, and already extensively consulted methodology (e.g. in the annual framework of the strategic reserves). It was also clearly stated that the consultation aimed at receiving any suggestion for sensitivities around the suggested central scenario. The non-confidential contributions and a comprehensive consultation report, answering each remark that was received, are publicly available on the Elia website [ELI-5] and were presented to the market parties in a Task Force meeting on April 1st 2019.

TIMELINE STAKEHOLDER INTERACTION [FIGURE 1-3]



BOX 2: INTEGRATION OF THE RECEIVED STAKEHOLDER FEEDBACK DURING THE PUBLIC CONSULTATION

The public consultation led to a vast number of stakeholder reactions. In addition to the remarks made during the workshop on the 22nd of January (reflected in the published minutes of the meeting [ELI-6]), in total seven stakeholders (of which two confidential) provided written comments for over a hundred remarks, suggestions of sensitivities or questions. The five public reactions were provided by:

- CREG;
- FEBEG;
- FEBELIEC;
- COGEN Vlaanderen;
- D. Woitrin (ACER).

This feedback was very much appreciated and has duly been taken into account.

Requested sensitivities

A large number of sensitivities were requested by the stakeholders and can be summarized as follows:

On the Belgian level:

- A nuclear life-time extension [CREG, FEBELIEC];
- Sensitivity on the demand growth: different source [FEBEG] or low growth [FEBELIEC];
- Lower growth for renewable energy sources [FEBEG];
- Additional new CHP capacity (+1GW) [CREG, FEBELIEC, COGEN];
- Lower CHP capacity (-1GW) [FEBEG, COGEN];
- Existing thermal capacity in structural block [CREG];
- Market response volume in function of results [CREG];
- Lower storage as it won't develop without support [FEBEG, ACER];
- Additional unit in Coo [ACER];
- Lower market response as won't develop without support [FEBEG];
- Additional diesels/turbojets [CREG, FEBELIEC];

On the European level:

- Reduced thermal in Central-West Europe [FEBEG], replace coal by gas abroad [CREG];
- CO_2 price [CREG], carbon price sensitivity [FEBEG].

In order to duly take these stakeholder requests into account, ALL those sensitivities have been calculated or taken into account in the scenario framework (e.g. all existing units are considered). The sensitivity 'market response volume in function results' was replaced by another sensitivity 'higher market response volume of +1 GW' which is complemented with the fact that in the 'economic viability check' the model can also invest in additional market response (if viable). In such case, the market response volume is 'in function' of the results.

Additionally, sensitivities on the price cap of the market, different WACC assumptions and investment costs ranges are used. Those sensitivities are integrated and quantified in Chapter 2 and results are available in Chapter 4.

Data Source

The stakeholders provided a series of suggestions for data to be used for the analysis. Whenever the suggested source could objectively be used and is externally available for all market actors, this was taken into account. Among others, changes were brought to the following parameters:

- Consumption growth was aligned with the draft NECP (scenario WAM);
- Installed capacity for renewable energy sources (onshore and offshore wind, pv and biomass) was aligned with the draft NECP (scenario WAM);
- Grid development projects to be taken into account for Belgium were fully aligned with the recently approved 'Federal development plan' and with the reference grid of the TYNDP 2018 for other countries;
- Investments costs table was reviewed with additional sources and other technologies were also added (existing units refurbishment costs, gas engines, diesels, ...);
- All units are now considered when new capacity is needed in the system (and not only new CCGT/OCGT);
- Creation of a new category (CCGT-CHP) to reflect the ability of 2 CCGT units to operate in CHP mode.

Additionally, Elia received specific information concerning the characteristics of generation (combined heat and power technologies), storage and demand-side management (market response) technologies. This allowed Elia to more accurately examine the potential flexibility of each technology and in particular for combined heat and power generation units.

Clarification

Several requests were received for more explanation and clarification. In addition to the clarification brought in the consultation report, this report also places more emphasis on several aspects where more explanation may be necessary:

- Data sources used for the 'CENTRAL' scenario were clarified;
- Grid assumptions to be based on the latest grid development plans aswell as the CEP min70% rule is taken into account from 2025;
- In order to take the min70% rule into account in a 'flow-based' environment, a new methodology has been developed and is described in this study;
- Introduction of the 'GAP volume' in addition to the defined 'structural block' volume to allow comparison with previous studies;
- Data for neighbouring countries are detailed in this study (with link to more detailed reports when available);
- Clarification on storage split of capacities and associated reservoir durations;
- Definition of total demand;
- Definition used for forced outage characterization;
- Existing thermal units in the structural block;
- Market responses/diesel assumptions.

This is done throughout the report, and also by providing some more technical explanations in the annexes to this study.

Several clarifications were given on the objectives, methodology and assumptions of the flexibility analysis. Specific clarifications were given towards the relation between the system's flexibility needs and Elia's balancing needs and the assumptions made concerning outage probability (and how offshore storm cut-offs are taken into account) and how Elia takes into account flexibility from cross-border, market response and new capacity to complete Belgian's adequacy needs.

Additional analysis on the results performed

It was also requested if the analysis could include whether grid or availability of generation abroad is constraining the imports to Belgium during scarcity periods. This has consequently also been analysed and mentioned in this report.

Data transparency

In addition to this report which includes detailed assumptions and describes the methodology of the study, an Excel file containing all data used for Belgium, economic assumptions, flexibility characteristics and 'flow-based' domains constraints are published together with this study.

Finally, this report has been presented to an extended Elia Users' Group on June 28th, sent to the Minister and the FPS Economy and made public on the same day. All of the steps are summarised in Figure 1-3 which gives an overview of the stakeholder interaction timeline.

1.3. Overview of improvements since the previous study

Elia has been performing probabilistic studies for a decade now and has always been a frontrunner in new methodological developments. Since the first study evaluating the 10 year adequacy and flexibility forecast of the Belgian power system published in April 2016, several improvements have been introduced in the methodology for assessing adequacy and flexibility. In fact, a new methodology, including a new scope and objective, has been introduced for the flexibility study compared to the one of 2016.

On top of the aforementioned improvements in terms of the governance of the study (public consultation, concertation/collaboration with the regulator, FPS Economy, Federal Planning Bureau, ...), further improvements have also been brought into the methodology and data. These improvements will be highlighted throughout the next chapters, but a concise overview is already provided below (with references to the associated sections for more information):

List of changes and improvements concerning data quality and transparency:

- The climate dataset used is fully aligned with the most recent release used by ENTSO-E (see Appendix E.2);
- The construction of consumption profiles is based on the tools recently developed by ENTSO-E (see Section 2.5.1.1);
- Data on generation, storage, consumption and demand flexibility for foreign countries are taken from the most recent release of the ENTSO-E dataset (see Section 2.6);
- An increased number of scenarios and sensitivities is simulated in order to capture future uncertainties around European assumptions, economics, cross border capacity calculation, national developments, etc. The flow-based market coupling (including the most recent CEP rules) is simulated for the CWE zone (see Chapter 2 and Appendix B);
- Assumptions on market response are further detailed (shifting, shedding) (see Section 2.5.2.2).

List of changes and improvements related to the flexibility methodology:

- The objective and scope of the flexibility study is enlarged from Elia's balancing capacity needs towards the general flexibility needs of the system (see Section 3.4);
- A new methodology is implemented to calculate the Belgian flexibility needs (see Section 3.4.2);
- A new methodology is implemented to integrate the flexibility needs in the adequacy assessment and assess the available flexibility means based on the adequacy assessments (see Section 3.4.3).

List of changes and improvements related to the adequacy methodology:

The methodology used in the previous study was already compliant with the European Resource Adequacy Assessment (i.e. MAF). Several improvements were adopted in order to take new developments or technologies into account:

- The modelling of storage (in addition to pumped storage) is introduced (see Section 2.5.2.1);
- Forced outages on HVDC interconnectors (as done in the European Adequacy assessment) are applied (see Section 2.5.3 and 3.1.3.1);
- An economic viability assessment on existing and new capacity is performed (see Section 3.2);
- A methodology was developed to take into account countries which have put a capacity mechanism in place to ensure their adequacy criteria are consistently met (see Section 2.6.7).

1.4. Structure of the report

This report contains **five chapters**, complemented with additional background information bundled in the **annexes**. In addition, there is a list of **abbreviations** and a full reference to the used sources in the **Bibliography and References** part. Separately, an Excel-document is published on the Elia website with all the data that was used for Belgium.

All elements related to the legal assignment as mentioned in Section 1.1.2 are included in the five chapters in the body of the report. Furthermore, given Elia's role as market facilitator and expert in matters of security of supply, **additional information is provided on the economics of the results**. This analysis builds further on earlier adequacy reports and provides answers to a number of questions received from market actors and the regulator during the public consultation on the data.

THE REPORT IS DIVIDED IN SIX PARTS [FIG. 1-4]

1. INTRODUCTION
2. SCENARIOS AND ASSUMPTIONS
3. METHODOLOGY
4. SIMULATION RESULTS
5. CONCLUSIONS
6. APPENDIX

In general the approach of the study is as follows: first a general introduction is provided, followed by an extensive explanation on the data and assumptions and the detailed methodology. The assessment itself starts first with a flexibility needs assessment for Belgium for different scenarios and sensitivites. An adequacy assessment is performed afterwards, for the same scenarios, to which additional sensitivities are performed to calculate the needed capacity in Belgium. If a capacity need is identified, an economic viability check is performed on existing and new capacity to see whether they would be viable in the market with the current market design. If the last step still results in an 'in the market' need that would not be covered by current energy market signals, several options are considered to fill the identified gap in the market. Those options are compared in terms of economics, market welfare, etc... and are used as basis for the flexibility means calculations.

Chapter 1 serves as introduction to this study and presents the relevant background, context and structure of the report. It also details the stakeholder involvement process and provides an overview of similar studies.

Chapter 2 takes an in-depth look at the key scenarios and assumptions. The focus here is on available generation, storage, flexibility resources and consumption in Belgium as well as the situation in neighbouring countries. The cross-border exchange assumptions are also detailed. An overview of the economic assumptions is provided.

Chapter 3 sets out the methodology that is used for the adequacy and flexibility part, including the economic impact assessment.

Chapter 4 provides the simulation results for the identified horizons. It includes the results of the different scenarios and sensitivities on the needed volume and the flexibility needs and means, including several economic viability checks on the basis of the economic assessment.

The study ends with **Chapter 5** setting out the conclusions of this report.

Additional information on data, methodology and results are available in **Appendix**.

2 Scenarios and assumptions

This chapter elaborates on the current energy trends, the scenario framework and the assumptions used in this study. A coherent set of hypotheses is defined and reflects a wide range of possible futures for the European and Belgian electricity systems. A '**CENTRAL' scenario for Belgium** is constructed based on expected trends and policies on which **a large amount of sensitivities is also applied as requested by stakeholders.**

The 'CENTRAL' scenario for Belgium combines:

- The **draft NECP ('With Additional Measures' scenario - WAM) for Belgium** as the basis for RES, nuclear generation and consumption;
- The '**Energy Pact' figures for Belgium** as the basis for newly developed market response and storage;
- All **existing generation units** are taken into account;
- An **economic viability check** is performed on **both existing** generation units and **any kind of new capacity** (generation, storage and market response);

As a basis for the other countries, the study uses the latest data from the European Adequacy Assessment performed at ENTSO-E level (MAF – Mid-Term Adequacy Forecast) complemented with the most recent dataset available for each country and collected within ENTSO-E. It is complemented with a 'Hight Impact Low probability' scenario as currently used in the framework of the strategic reserve volume evaluation. Sensitivities are also applied on those scenarios.

The 'EU-BASE' and 'EU-HiLo' scenarios combine:

- For other countries:
  - The **latest planned developments in Europe** (draft National Energy and Climate Plans (NECPs), announced coal phase outs, CRMs, RES development, …);
  - For the **'EU-HiLo'**, an **additional unavailability of 4 nuclear units in France** (on top of the 'normal unavailability'.
- For cross border capacities:
  - The **CEP min 70% rule** for cross-border capacity calculation in 'flow based' methodology.

In addition, economic and flexibility assumptions are also taken in order to perform economic dispatch simulations and the flexibility assessment.

Economic assumptions are based on:

- The **scenarios from the IEA** ('World Energy Outlook 2018') as the basis for fuel and carbon price developments;
- A **large amount of sources for investment, fixed and variable costs of existing and new capacities;**
- A sensitivity on the **market price cap**.

Assumptions concerning flexibility are based on:

- An extensive literature study for **flexibility characteristics of all considered technologies** (including ramp rate, minimum up/down time, (hot, warm, cold) start up time, minimum stable power);
- **Forced outage characteristics** of generation units and HVDC-interconnectors based on historic observations (ENTSO-TP);
- Elia's **total load and variable generation prediction data**, as seen on its website.

This chapter is divided in 9 sections:

Section 2.1 gives an overview of the trends in the electricity system in Belgium and Europe.

Sections 2.2 and 2.3 define the study's framework with a definition of targeted time horizons and of the geographic perimeter included for this analysis.

Section 2.4 deals with the scenario framework and outlines the sources used for the quantification of scenarios and sensitivities.

Section 2.5 provides all the details regarding Belgian assumptions and sensitivities.

Section 2.6 provides more information on the generation and demand assumptions used for European countries.

Interconnection modelling and **cross-border exchange** assumptions as well as the 'flow-based' methodology used in this study are described in **Section 2.7.**

The data used for the flexibility assessment are further detailed in **Section 2.8**

Finally, fixed and variable costs as well as the investment costs of the different technologies used for market simulations and economic assessments are detailed in **Section 2.9.**

2.1. Trends in the electricity sector

This section aims to provide a non-exhaustive overview of recent trends and expected developments in the electricity sector in Belgium and Europe. Those trends are key in understanding the ongoing and upcoming changes in the system. Those evolutions are also the basis upon which the scenario framework and the sensitivities are constructed.

2.1.1. Key facts about the Belgian electricity system

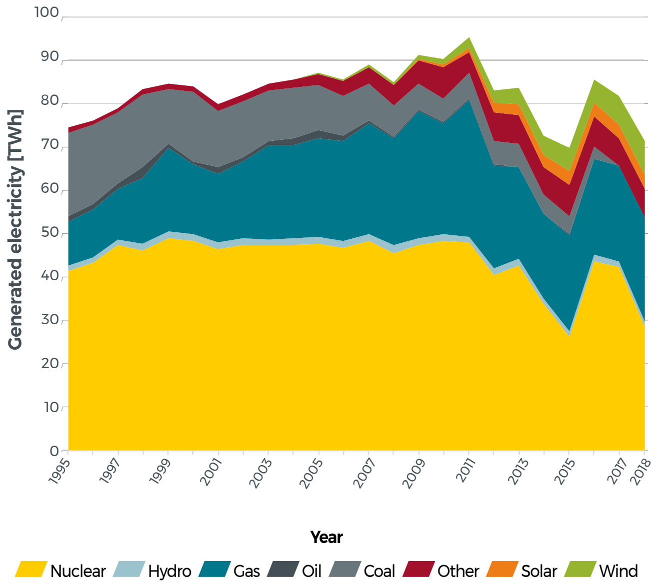
After being gradually replaced by natural gas over the past 20 years, the last coal unit was phased out in 2016

Belgium has been relying on coal for its electricity generation for decades. Since 1990 the coal units have gradually been replaced by gas-fired generation. This evolution was completed in 2016 with the closure of the last coal-fired unit. Natural gas became the second-most used primary resource for electricity generation from 2000 and has gradually increased in importance to actually represent around 30% of generated electricity today.

Nuclear generation, representing 50% of the total electricity produced, is planned to be phased-out in the next 5 years

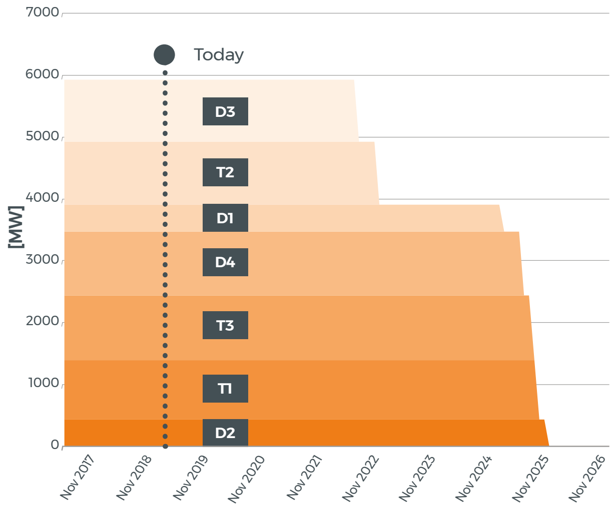
Belgium has been relying on nuclear energy for most of its electricity generation for more than 40 years. Nuclear generation represents around 50% of the electricity produced in the country (depending on the availability of the nuclear fleet). In terms of generation capacity, nuclear also represents around 50% of the thermal capacity of the country. The upcoming phase-out (which is to be completed by the end of 2025 according to the law [GOV-1]) will lead to several challenges and changes which are emphasised and analysed in this study.

HISTORICAL GENERATED ELECTRICITY IN BELGIUM SINCE 1995 (PER FUEL) [FIGURE 2-1]



Source: FPS Economy

EVOLUTION OF EXISTING NUCLEAR GENERATION IN BELGIUM [FIGURE 2-2]



Belgium is a front-runner on the development of offshore wind farms

Despite the fact that Belgium has the smallest exclusive economic zone in the North Sea, offshore wind generation capacity will reach 2.3 GW by the end of 2020. Additionally, a future increase of this capacity to 4 GW is also planned. Although Belgium has very good wind conditions, such an increase will bring new challenges regarding the ability to operate the electrical system and to ensure a reliable electricity supply. Those aspects are also tackled in the present study.

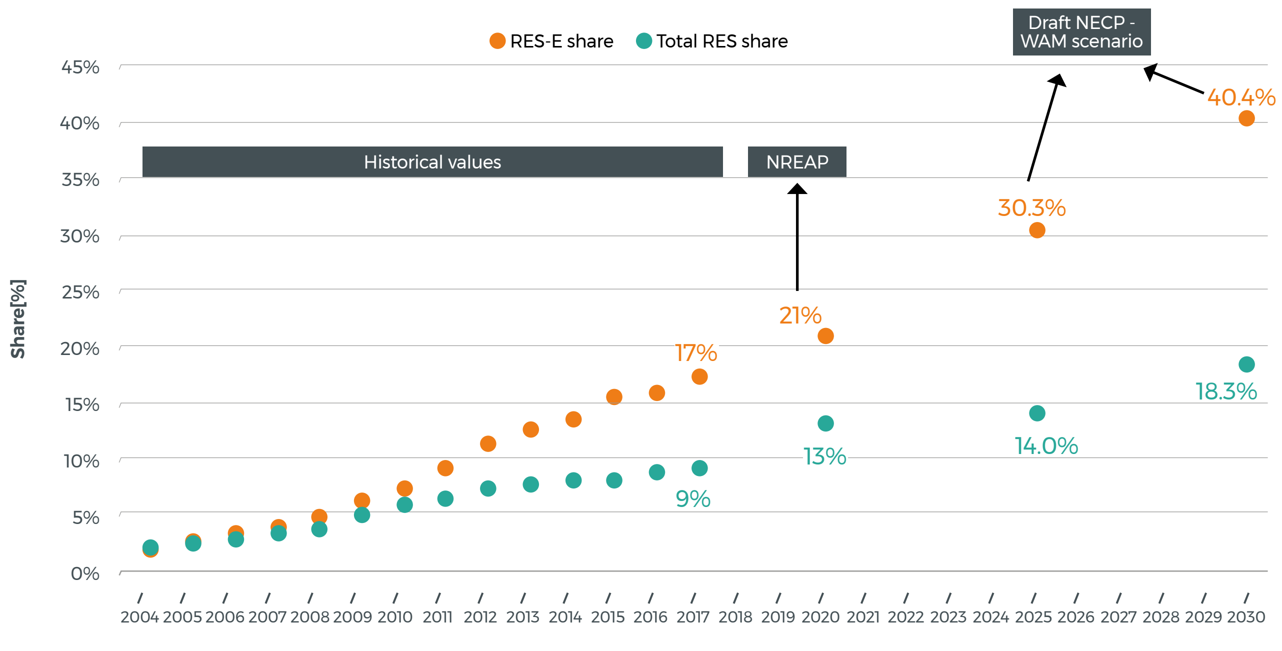
Belgium is one of the most interconnected countries in Europe

Given its location in the heart of Europe, Belgium has had an important focus on developing interconnections in order to facilitate market integration, improve efficiency and bring welfare for the European and Belgian society. Nowadays, Belgium can import or export more than 40% of its peak consumption (if the energy is available abroad and market conditions are favourable). This value will further increase in the near future thanks to for example the new HVDC interconnection with Germany (ALEGrO) which is currently being realised.

The RES-E share of Belgium was around 17% in 2017. Thanks to further RES development, this share could reach 40% by 2030 (based on the draft NECP submitted to the EC)

The RES-E share of the Belgian electricity consumption represented around 17% in 2017. This share is planned to at least double by 2030 (based on the draft NECP - WAM scenario). Figure 2-3 shows the historical RES shares in Belgium, the 2020 targets and 2030 proposed targets for the total RES (RES share of total energy consumption) and RES-E (RES share of electricity consumption) share. More information on RES and RES-E share can be found in BOX 4.

RES SHARE OF ENERGY AND ELECTRICITY CONSUMPTION IN BELGIUM [FIGURE 2-3]



Sources: [OBS-1] [EUC-3]

RES share of electricity consumption. Estimated target from the NREAP for 2020 and draft NECP submitted to the EC for 2025 & 2030

RES share of total energy consumption. Binding 2020 Target (from NREAP) - 13% 2025 & 2030 based on draft NECP submitted to the EC

2.1.2. European targets

Long term strategy

On 28 November 2018, the European Commission presented its strategic long-term vision for a prosperous, modern, competitive and climate-neutral economy by 2050. This strategy is in line with the 'Paris Agreement' aiming to keep the global temperature increase well below 2 °C and pursue efforts to keep it to 1.5 °C. Such an ambition would require a **reduction of greenhouse gas emissions by at least 85%** (compared to 1990 levels) in 2050.

This long-term vision has now been complemented with the 'Clean Energy for all Europeans' (CEP) package (cf. introductory chapter) which includes new targets for 2030 on renewable energy and energy efficiency among others.

The EU has set intermediary goals to reduce greenhouse gas (GHG) emissions by 20% in 2020 and by at least 40% in 2030 (compared to the 1990 levels):

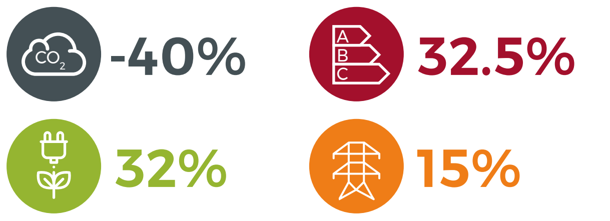
- The EU is responsible for the GHG emissions that fall under the EU Emissions Trading System (ETS). Electricity GHG emissions are part of the ETS;
- Each member state is responsible for the non-ETS emissions. Binding targets were set for each member state. For Belgium, the proposal is to achieve a 35% reduction for the non-ETS sectors in 2030.

For 2030, each member state has submitted a draft National Energy and Climate Plan (draft NECP) to the EU at the end of 2018 which may be further consulted and adapted in order to reach the overall EU 2030 targets.

For 2030, the EU has set the following targets (at EU level):

- **At least a 40% reduction in greenhouse gas emissions** (compared to 1990 levels). This target was agreed at the level of the Heads of State and government;
- **Energy efficiency** target of a **minimum of 32.5%** (reduction compared to 2007 modelling projections for 2030 which results in no more than 1273 Mtoe of primary energy consumption and no more than 956 Mtoe of final energy consumption);
- **Renewable energy** binding target (at EU level) of the final energy consumption of a **minimum of 32%**;
- **Interconnection targets** for all Member States of **15%**.

2030 TARGETS SET BY THE EU [FIGURE 2-4]



Targets are set on the renewable share of total energy consumption. It is nevertheless possible to extrapolate possible ranges for RES in the electricity consumption (RES-E) which will be required in order to achieve the global target. Those extrapolations are indicative as they depend on the level of consumption and the development of RES in other sectors.

BOX 3: THE EUROPEAN EMISSIONS TRADING SYSTEM (EU-ETS)

There are no national targets for electricity GHG emissions

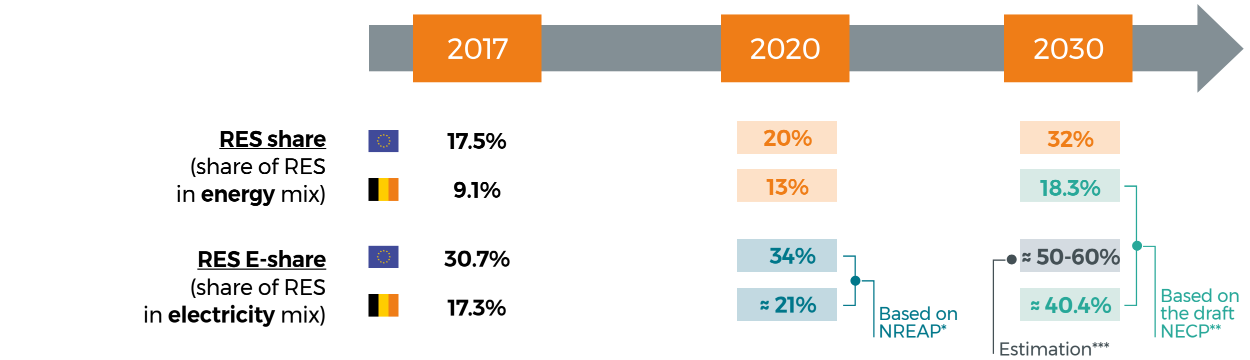
Those emissions are dealt with on the European level in the ETS. Electricity can easily be imported or exported depending on market conditions. Therefore, setting national targets has no or little value given that imported energy and its associated emissions are not accounted for in national values. Such reasoning is even more valid for a country like Belgium where imports could reach up to 50% of the future annual electrical consumption (depending on market conditions and the capacity mix).

How does the EU-ETS work ?

Electricity falls under the EU-ETS. It consists of a cap and trade system where companies receive and can trade emission allowances. The cap (i.e. the maximum amount of emissions that can be emitted per year) is reduced over time in order to achieve the targets. A carbon price reflects the supply and demand of allowances. More information can be found at [EUC-1].

BOX 4: RES TARGETS AND TRANSLATION TO ELECTRICITY SECTOR

RES TARGETS ON ENERGY AND ELECTRICITY CONSUMPTION IN EUROPE AND BELGIUM [FIGURE 2-5]



* The RES-E share target is an estimation as it depends on the developments in other energy sectors (transport, heat, ...), shifting between sectors (electification, ...) and energy efficency. Those data are based on NREAP that were submitted by each country [EUC-3], [EUC-4].

***based on [KOT-1]

**based on the draft NECP sent by Belgium end of 2018

RES targets in relation to the total energy consumption

Country based targets for the share of renewable energy in **2020** were defined to achieve the **20% target of renewable energy in the final energy consumption**. Following the Renewable Energy Directive (2009/28/EC), each country has submitted a National Renewable Energy Action Plan (NREAP) explaining which measures and mix are pursued in order to reach the binding targets [EUC-2].

Belgium has committed to a share of 13% (RES share) of energy to be generated from renewable sources in relation to the final energy consumption. The NREAP for Belgium provided forecasts for renewable shares in the main energy sectors: Heating/Cooling, Transport and Electricity.

For 2030, the European Commission proposed a 32% EU-binding RES target as part of its 'Clean Energy for all Europeans' package. At the end of 2018 each Member State submitted a draft Integrated National Energy and Climate Plan (as part of the European Energy Union Governance framework). For Belgium, the RES share proposed in the plan accounts for **18.3% in 2030**. Those values are subject to change following the ongoing process to agree on a country breakdown for 2030.

RES targets in relation to electricity consumption (RES-E)

Given that the present study only covers the electricity sector, an estimation of the targeted RES penetration in the electricity sector is needed. The targeted RES-E share (share of renewables in the electricity consumption) depends on developments in the other sectors as the final targets are set on the total energy consumption.

In 2017, the Belgian RES share of the energy consumption was 9%, and renewable electricity generation on final electricity consumption was 17%.

For 2020, an EU RES-E share of 34% was estimated, based on the NREAP that each country has submitted. For Belgium 21% is expected to be the RES-E share to achieve the total RES energy targets.

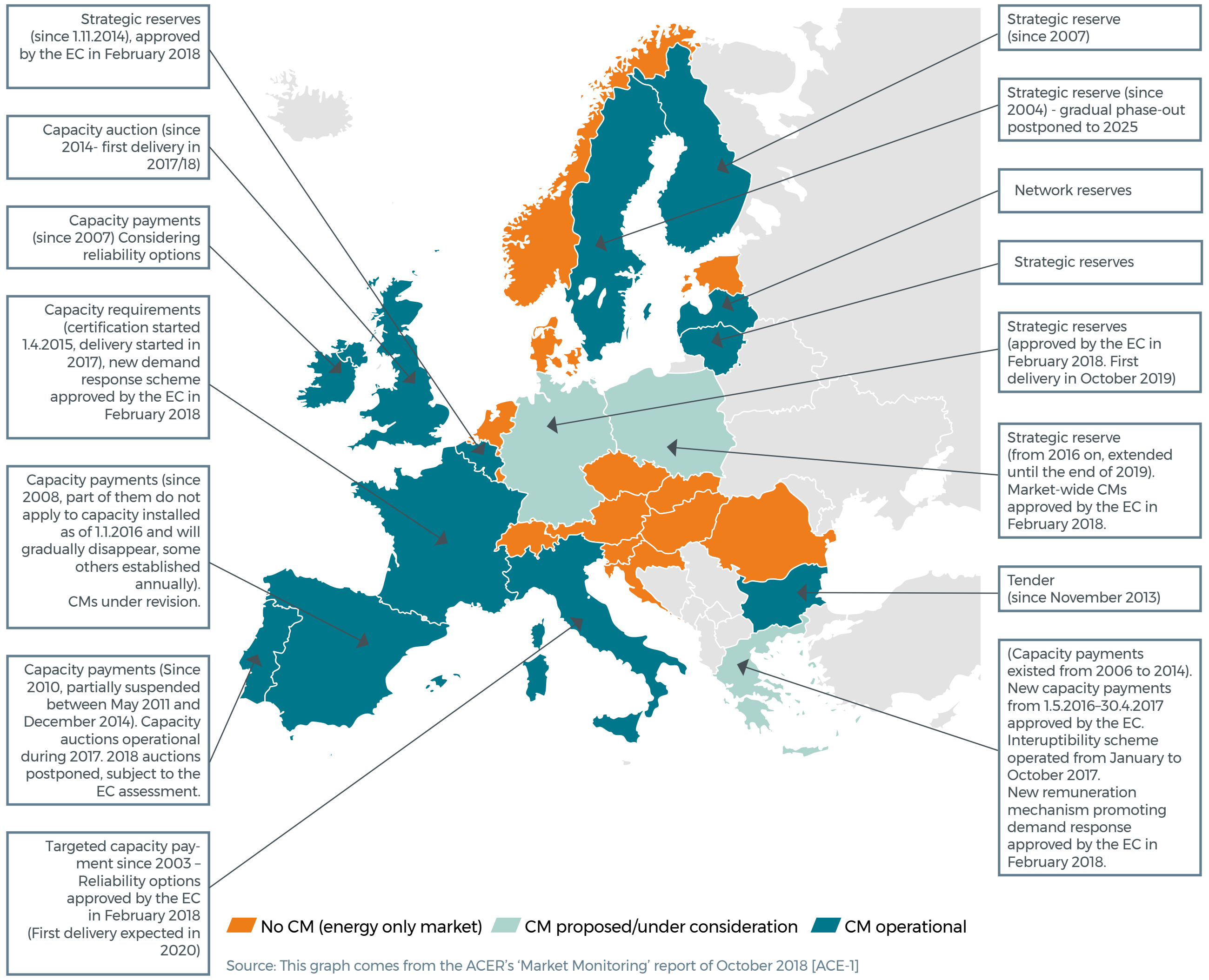
For 2030, the breakdown of RES targets for electricity is estimated to be around 50-60% for Europe and around 40% for Belgium (based on the draft NECP). Those values are subject to change.

2.1.3. Adequacy market mechanisms

Throughout Europe more and more countries are relying on capacity mechanisms to ensure an adequate supply. The precise driver for this choice and the nature of the capacity mechanism installed varies across Europe. As a common denominator, however, one could notice that these markets are no longer solely relying on energy market revenues to ensure a sufficient level of installed capacity for maintaining security of supply.

In its yearly Market Monitoring Report, ACER provides an overview of all the capacity mechanisms in Europe. The map in Figure 2-6 below covers all capacity mechanisms in place in 2017 as published in ACER's report of October 2018 [ACE-1]. Note that meanwhile additional mechanisms are being considered and developed, such as those in Belgium and Lithuania.

OVERVIEW OF CAPACITY MECHANISMS THROUGHOUT EUROPE [FIGURE 2-6]



Source: This graph comes from the ACER's 'Market Monitoring' report of October 2018 [ACE-1]

Notwithstanding the distinct nature of each installed or foreseen capacity mechanism, generally three groups can be distinguished:

- **Market-wide capacity remuneration mechanism** (CRM) (e.g. FR, GB, PL, IR, IT): In such market-wide mechanisms all capacities, irrespective of their technology or whether they are existing, new or undergoing refurbishments can participate. Each capacity can be remunerated proportional to its assumed contribution to adequacy, typically by means of a de-rating factor (e.g. a thermal unit proportionally contributes more than capacity subject to energy constraints or depending on climatic conditions). All these capacities contracted in such a mechanism continue to operate in the energy market without any intervention from the CRM on the dispatch decision, i.e. those capacities are 'in-the-market'. Whereas most CRMs are typically centrally organised with a single buyer, also decentralised designs exist. As pointed out by the European Commission in its 2016 Sector Inquiry [EUC-3] focusing on capacity mechanisms, such mechanisms provide an appropriate solution when longer term adequacy concerns are identified and long-term commitments are needed to foster new investments.
- **Strategic reserve** (SR) (e.g. DE, FI, SW, BE): A strategic reserve typically operates 'out-of-market', which means that the capacity held as strategic reserve cannot participate in the energy market like any other capacity. It can only deliver energy when called upon during periods of (anticipated) scarcity, typically reacting on a (strong) market signal and/or a signal given by the TSO. Strategic reserves are procured following a market-based tendering process amongst eligible capacity. According to the European Commission in its 2016 Sector Inquiry, strategic reserve could be useful to overcome shorter periods of adequacy concerns, provided there is sufficient capacity available in the system that might otherwise be at risk of leaving the system. They are less appropriate as a tool to foster new investments typically requiring longer term commitments.
- **Capacity payment** (CP) (e.g. ES, PT): Capacity payments are a price-based mechanism (in contrast to volume-based mechanisms like market-wide CRMs and strategic reserve) that provide an administratively-set side payment to eligible capacity. Such a mechanism is not market-based.

As mentioned in the introductory chapter, a strategic reserve mechanism is currently in place in Belgium and recently the Electricity Law has been amended with the aim of installing a market-wide capacity remuneration mechanism.

At European level such mechanisms are typically considered as so-called state aid and therefore the European Commission (DG Competition) has to be notified to verify their compliance with Guidelines on State aid for environmental protection and energy (EEAG). Moreover, as from 1 January 2020 the Clean Energy Package, via the Regulation dealing with the Internal Energy Market, also provides a framework for capacity mechanisms, including strategic reserves covering mainly implementation, design and cross-border aspects.

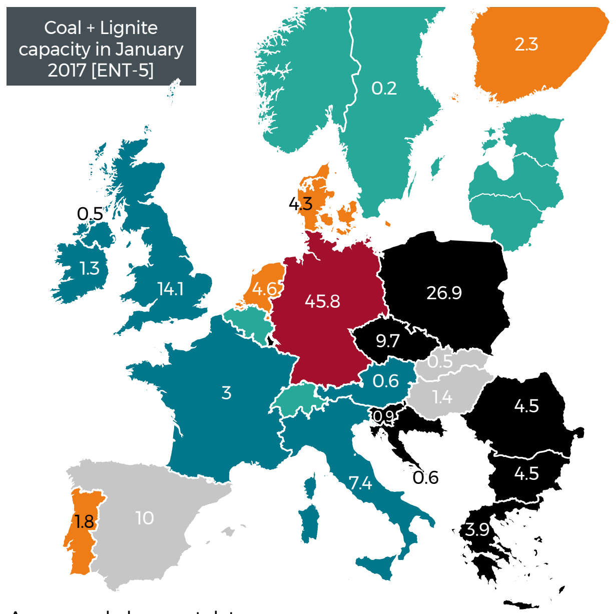
2.1.4. Coal phase outs

One of the major changes expected in the European electricity system since the publication of the previous 10-year adequacy & flexibility study' in 2016 are the coal phase out announcements in Western Europe. Several countries have the ambition to close or to drastically reduce their coal and lignite fleet in the upcoming decade. Those countries are mainly concentrated in Western Europe. The following Figure 2-7 gives an overview of the announced ambitions.

The phase out of coal will lead to lower emissions from the European power sector. Those decommissionings could however also lead to adequacy concerns in countries that are relying on a large share of coal and lignite capacity (and their neighbours if they rely on imports for their adequacy). The properties of thermal generation (to which coal generation belongs) allow the high availability of electricity production during moments of scarcity (as there are not limited by energy nor activation constraints).

The latest known policies and ambitions from each country are integrated in the scenarios used in the present study.

OVERVIEW OF COAL PHASE-OUT DATES IN EUROPE [FIGURE 2-7]



Announced phase-out dates

- By 2020 or no coal
- By 2025 or earlier
- By 2030 or earlier
- By 2040 or earlier
- No known date
- Under discussion

Source: [BEY-1]

2.1.5. Electrification

Electricity is seen as the major contributor to the decarbonisation of the economy in most long-term studies. There is a broad consensus between long-term energy studies on this [EUC-4] which is mainly due to three reasons:

- Technologies are available to produce electricity from renewable sources (PV, wind, hydro, biomass, geothermal...);
- If electricity is produced from renewable sources, it saves the production and transportation energy/emissions of the needed fossil fuels, as well as the transformation losses when using those to produce electricity (while losses to transport electrical energy itself remain fairly low);
- Mature technologies exist to easily convert electricity to any other form of usable energy (heat, movement...) and with high efficiency rates.

With the increased European ambition to reduce GHG emissions and local authorities to ban certain types of fossil based transportation, electrification of the transportation and heating sectors will rise in the future.

Several cities across Europe have also announced their ambition to ban diesel vehicles or petrol cars, and some have already put in place a 'low emissions zone (LEZ)': Paris, Rome, London, Madrid, Amsterdam, Oslo, Brussels, etc. It is widely expected that such regulations will lead to more electric vehicles in the coming years.

2.1.6. Enabling flexibility at the customer side

With the increase of decentralised generation, electrification of heat and mobility and decarbonisation ambitions, the customer will certainly play a key role. The energy transition will also need to happen at the customer side to fully unlock their flexibility potential. Such a transformation is also supported by the 'Clean Energy for All Europeans' package.

In November 2018, Elia Group published a Vision Paper outlining better services and optimised energy bills for consumers. 'Towards a Consumer-Centric System' encourages households and industries to directly benefit from advanced energy services via a real-time communication platform, an appropriate market design and digital innovations. This will enable end users to fully exploit their technological investments, optimise their electricity bills and contribute to system balance.

Enabling a Consumer-Centric System requires three building blocks:

- A real-time communication platform;
- An upgraded market design;
- New digital tools.

More information on the vision [ELI-7] and ongoing developments [ELI-8] can be found via the associated sources.

Such developments are also integrated in this study by giving attention to decentralised flexibility and demand side response. Assumptions are taken on 'Vehicle-to-Grid' (V2G), demand shifting, small scale batteries at household levels, etc.

2.1.7. Further grid development

The ambitious path Europe engaged on towards decarbonisation and a rapid replacement of fossil fuel generation by renewable energy sources can only be considered successful if both the costs of transforming the system are kept as low as possible and the continuous secure access to electricity remains guaranteed for all citizens.

In both of these requirements the high-voltage grid plays a key role. An appropriate set of investments is to be realised in order to enable better market integration, as well as contributing to overall security of supply. It is vital to acknowledge that the construction of grid infrastructure has a longer lead time than renewable energy projects. Therefore, to make the energy transition a reality and reap the most benefit from it, it is in society's interest that transmission infrastructure is built in time.

On the European scale, ENTSO-E's 10-year network development plan (TYNDP) abridges, enables and complements the national development plans. It looks at the future power system in its globality and how power links and storage can be used to make the energy transition happen in a cost effective and secure way. The TYNDP describes a series of possible energy futures jointly built with ENTSO-E's gas counterpart, ENTSO-G, and co-constructed with environment and consumer associations, the industry and any interested parties. It uses an approved European range of indicators to compare how electricity infrastructure projects help to deliver the European climate targets, market integration and security of supply. The latest issue of the TYNDP was published in November 2018, and can be found on ENTSO-E's website [ENT-2].

At Belgian level, the Federal Development Plan builds on the scenarios developed in the TYNDP framework, and identifies the transmission capacity needs of Belgium's high-voltage grid (110 to 380 kV). Furthermore, the plan describes the investment programme intended to satisfy these needs. The latest Federal Development Plan, targeting a horizon from 2020 to 2030, has been approved by the Federal Minister for Energy on April 26th 2019 and can be consulted on a dedicated website [ELI-9]. For the extra high-voltage grid (380 kV), this plan contains projects that reinforce the internal grid (backbone), integrate additional offshore wind generation and encourage the international exchange of electricity through the further development of interconnections. For the transmission system (110 kV - 150 kV – 220 kV), the plan contains projects that, for instance, replace ageing grid infrastructure, cope with expected economic developments at local level and further integrate renewable energy.

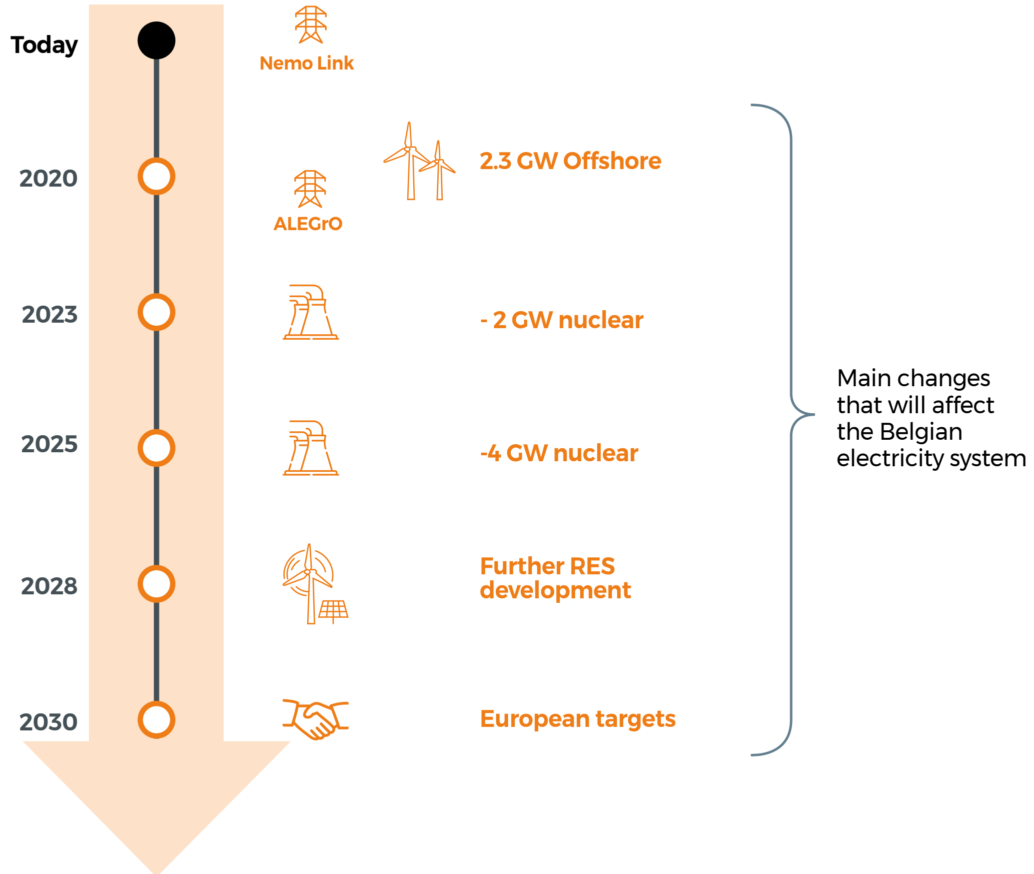
2.2. Studied time horizons

This study covers a 10-years horizon, from 2020 to 2030. This period was punctuated by 5 reference years, highlighting the significant changes expected in the Belgian electricity system:

- **2020:** corresponds to the expected situation in the 'short term' and the starting year of the study;
- **2023:** reflects the period when the first nuclear units are being decomissionned in Belgium according to the current law (2 GW for closure);
- **2025:** full nuclear phase-out in Belgium according to the current law (4 GW additionally closed);
- **2028:** the 'second offshore wave' is expected to be fully commissioned, enabling offshore capacity to reach 4 GW combined with continuous development of RES in Europe;
- **2030:** reference year for which European targets are defined. This time horizon is also quantified and analysed by several national and European studies.

5 time horizons are simulated in the study which cover the major expected changes in the electricity system

SELECTED TIME HORIZONS TO BE SIMULATED [FIGURE 2-8]



All time horizons are defined with a calendar starting from **September 1st of the mentioned year up to August 31st of the next year**. Therefore the year '2025' is to be understood as including the entire 'winter 2025-26'.

2.3. Simulated perimeter

Given the position of Belgium in the heart of the European electricity system and its structural dependency on electricity imports for its security of supply, the modelling has to include a large part of Europe. This will be key in accurately taking into account European developments into account that have an impact on the security of supply of our country.

The perimeter of this study includes twenty-one countries (named 'EU21' afterwards), as shown in Figure 2-9, namely:

- Austria (AT)
- Belgium (BE)
- Switzerland (CH)
- the Czech Republic (CZ)
- Germany (DE)
- Denmark (DK)
- Spain (ES)
- France (FR)
- Finland (FI)
- 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 current market zones' definition, and is identical to the approach used in other studies, e.g. at ENTSO-E.

In the assessment, 21 countries are modelled in detail. This makes it possible to determine the available generation capacity abroad when Belgium needs to import energy.

THE SIMULATION PERIMETER COVERS 21 EUROPEAN COUNTRIES = EU21 [FIGURE 2-9]

2.4. Scenario framework

The scenario framework is built around one **'CENTRAL' scenario** which is a combination of several parameters that are detailed in this section. On top of the 'CENTRAL' scenario, a large amount of sensitivities is simulated and taken into account to assess whether results can stand up to different assumptions. Those sensitivities were suggested by the stakeholders during the public consultation on data and assumptions. This section covers more precisely:

Belgian assumptions

- Policy driven technologies (existing and new RES, nuclear) and consumption;
- Storage, CHP and Market Response (existing and new);
- Existing and new thermal/turbojet generators;

European generation, storage, market response & consumption assumptions

- Policy driven technologies;
- European ENTSO-E database;
- Market wide capacity mechanisms (CRM);

Cross-border exchange capacities

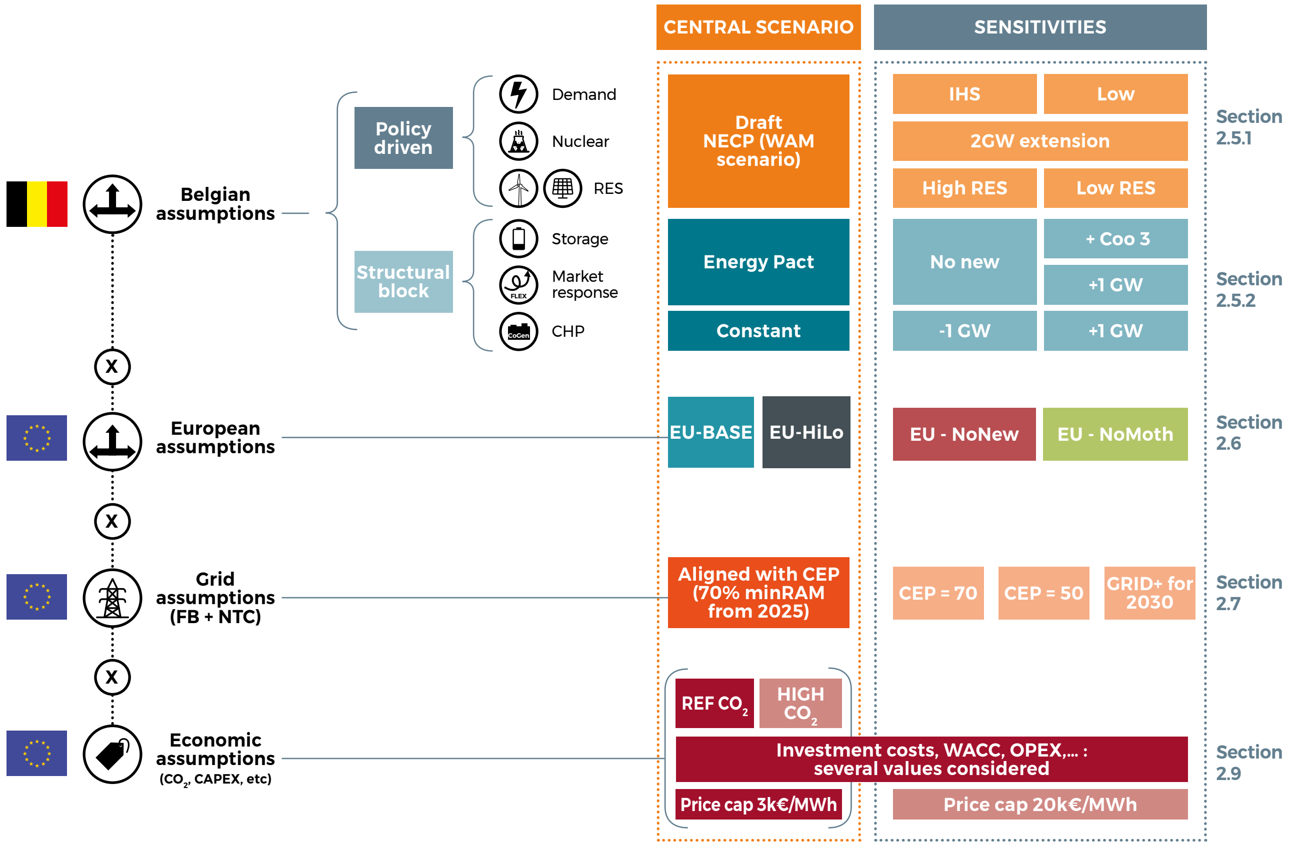
- Grid development assumptions;
- Flow Based capacity calculation for the CWE region;
- Net Transfer Capacities for countries outside of CWE;
- Additional capacity calculation rules (CEP targets);

Economic assumptions

- Variable costs of generation (fuel costs, emissions' cost, variable operation & maintenance costs);
- Fixed cost of generation;
- Investment or refurbishment costs;
- Price caps.

An overview of the different sensitivities is given in Figure 2-10. Their detailed definition is explained throughout the following sections.

OVERVIEW OF THE SCENARIO FRAMEWORK [FIGURE 2-10]



2.5. Belgian scenario and sensitivities

In order to assess the adequacy and flexibility needs for Belgium in the different time horizons described in Section 2.2, a 'CENTRAL' scenario was quantified based on public data and recent ambitions/targets proposed by Belgian authorities in order to comply with European targets for 2030.

Those ambitions/targets are officially defined through two main sources used for the construction of the 'CENTRAL' scenario.

Draft National Energy and Climate Plan (NECP) – 'With Additional Measures' scenario

The **draft version** of the **NECP**, as submitted by Belgian authorities to the European Commission on 31 December 2018 (see Section 1.1.4 for more info on the NECP), is used for the quantification of:

- **Offshore** and **onshore** wind, **photovoltaic** and **biomass** capacity as set by regional and federal authorities in order to reach EU 2030 targets (see Section 2.5.1.3);
- **Nuclear** capacity which follows the phase-out calendar as outlined in the law (see Section 2.5.1.2) [GOV-1];
- **Total electricity consumption growth** which includes the planned measures foreseen in the framework of the European energy efficiency targets for 2030. A forecast of DSO and TSO grid losses (not part of the final consumption definition used in the draft NECP) is also added (see Section 2.5.1.1).

The draft NECP for Belgium includes two scenarios as proposed by regional and federal authorities: the so-called WEM ('with existing measures') scenario considering measures already adopted and implemented and the so-called WAM ('with additional measures') scenario which takes additional measures into account.

This draft NECP version demonstrated that only the WAM scenario could be able to achieve EU targets, with the condition that the measures provided in this scenario are effectively implemented. On this basis, the CENTRAL scenario follows the **WAM scenario** regarding total electricity growth and RES assumptions.

'Energy Pact'

In the **'Energy Pact'**, as agreed upon by Belgian authorities in 2018, several ambitions were set for:

- **Market response volume** (shedding and shifting) for 2025 and 2030. The latest study conducted by e-Cube in the framework of the strategic reserve volume determination is also used for 2020/2021 [ELI-10]. This study follows a methodology that has been developed in close collaboration with the market parties [ELI-11]. A linear interpolation is applied between the first 3 years and the 'year 2025' from the 'Energy Pact';
- **Storage facilities** for 2025 and 2030 with linear interpolation between those targets and the current installed capacities.

Those assumptions are complemented with **all existing units** not considered in previous steps unless (temporary) decommissioning dates were formally announced before the 1st of April 2019.

Additionally, **any kind of new capacity will be considered** (on top of new capacity already considered in the above categories), **if viable** under different market design assumptions.

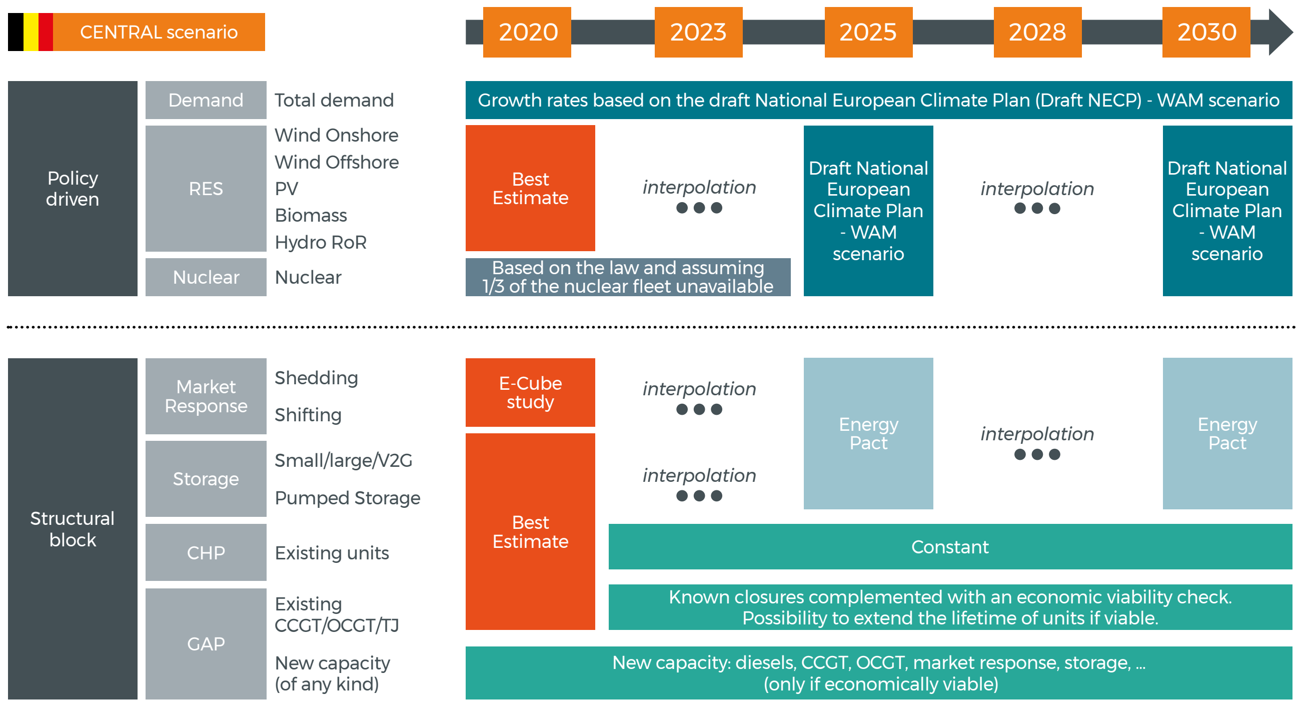
Figure 2-11 below summarises the sources used for the 'CENTRAL' scenario.

On top of this 'CENTRAL' scenario, several sensitivities for Belgium were performed in order to assess the robustness of the obtained results. All sensitivities are based on requests from the stakeholders during the public consultation organised about the input data used for this study (cf. Section 1.2). More specifically, the following sensitivities (for Belgium) are analysed in this study (for 2025-2028-2030):

- Another source for electricity consumption growth ('IHS Markit');
- Lower electrification leading to lower consumption growth;
- Higher growth for renewable energy sources;
- Lower growth for renewable energy sources;
- A nuclear life time extension of 2 GW after 2025;
- Higher market response volumes by 2025 (+1 GW on top of 'Energy Pact' figures);
- No new market response (from currently existing volumes);
- No new storage (from currently existing volumes);
- An additional pumped storage unit in Coo ('Coo 3');
- Additional new CHP capacity on top of the existing one (+1 GW);
- Lower CHP capacity compared to the existing one (-1 GW);
- Different economic assumptions to check the economic viability of existing and new capacity after 2025 (those are further detailed in Section 2.9).

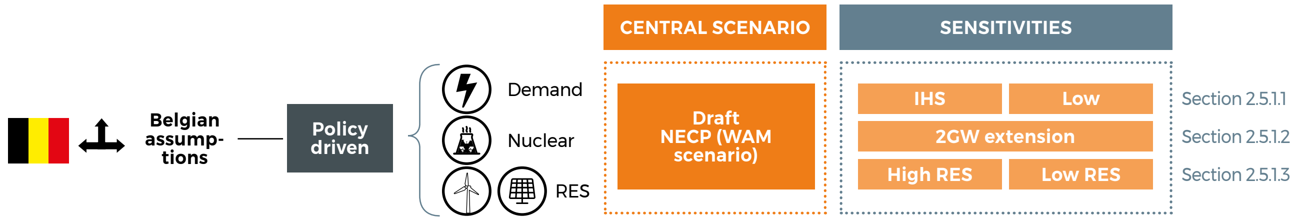
This section elaborates on the assumptions taken for the 'CENTRAL' scenario and for each sensitivity retained for this study.

OVERVIEW OF THE 'CENTRAL' SCENARIO FOR BELGIUM [FIGURE 2-11]



See Section 2.5.1 and 2.5.2 for "Policy driven" and "Structural block" definition

2.5.1. Policy-driven assumptions



2.5.1.1. ELECTRICITY CONSUMPTION

The 'CENTRAL' scenario follows the draft NECP consumption growth (WAM scenario).

As requested by stakeholders, sensitivities will be applied with:

- **a different source for the consumption growth ('IHS Markit') and;**
- **a sensitivity with lower electrification.**

The future consumption profiles (and hence the total demand) are constructed in three steps (see Figure 2-12):

1. Growth of consumption due to **economic growth/ population growth** and **energy efficiency** is applied on the normalised load profile;
2. **Additional electrification** of transportation and heating sectors is quantified and added to the profile;
3. **Thermosensitivity** of the consumption is applied which leads to different profiles and volumes for each climate year.

The model used for the creation of hourly load profiles for all European countries is called 'TRAPUNTA' (Temperature REgression and loAd Projection with UNcertainty Analysis) and comes in a new software application developed by Milano Multiphysics for ENTSO-E..

It allows to easily perform electric load prediction starting from data analysis of historical time series (electric load, temperature, climatic variables and other). In addition, TRAPUNTA incorporates the decomposition of time series into basic functions, which reduces the computational burden and required data fed into the forecast model.

In a second phase, TRAPUNTA adjusts load time series using TSOs bottom-up scenarios that reflect future evolution of the market (e.g., penetration of heat pump, electric vehicles, batteries). The forecast model reads a diverse set of data sources (historical load profiles, temperature time series, heat pumps, electric vehicles, etc.) and can provide multi-year demand forecasts in hourly resolution.

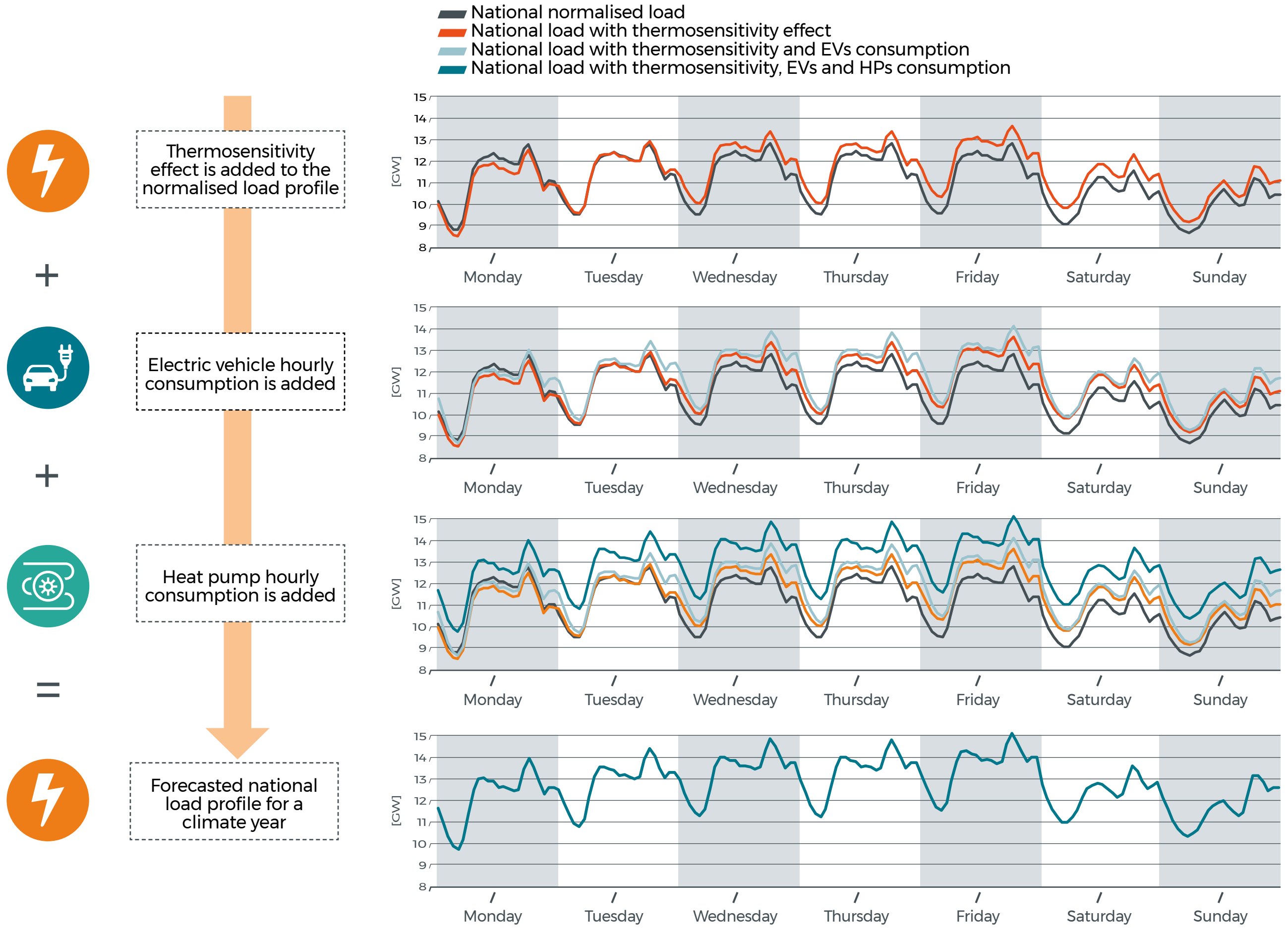
TRAPUNTA is a fundamental input to European adequacy studies performed by ENTSO-E. With regard to the past modeling approach, its utilization brings several advantages (non-exhaustive list):

- Multiple historical climate and load time series are used to derive forecasted load profiles for each market node. In the previous methodology, only one reference year was used during the forecasting process;
- 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.);
- The load forecast is decamped into temperature-dependent and temperature-independent components. That way, final load profiles are adjusted, taking into account added consumption from heat pumps and electric vehicle charging. This way, the forecasts also consider the interdependencies of historical temperatures of each climate year and historical load patterns.

More information regarding the model will be available in the Mid-Term Adequacy Forecast study that ENTSO-E will publish in November 2019.

The applied methodology therefore ensures consistency with the ENTSO-E methodology and with consumption profiles applied for other countries.

DEMAND CONSTRUCTION – ILLUSTRATION WITH A WEEKLY PATTERN [GW] [FIGURE 2-12]



BOX 5: WHAT IS THE DIFFERENCE BETWEEN TOTAL ELECTRICAL CONSUMPTION AND ELIA'S CONSUMPTION ?

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

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

What are the differences compared to Elia's consumption (more generally known as 'Elia grid load')?

The Elia grid load covers all offtake as seen from the perspective of the Elia grid. It is indirectly calculated based on the injections of electrical energy into the Elia grid, which includes 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 a net injection onto the Elia grid is measured.

The energy needed to pump water into the reservoirs 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 therefore 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.

What is published on Elia's website?

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

The published Elia grid load and total load [ELI-12] includes the load of the Sotel/Twinerg grid (which is not the case for the total load calculated in this study).

Scenario and sensitivities on the evolution of total demand

As requested by stakeholders, sensitivities with higher and lower consumption compared to the 'CENTRAL' scenario are performed:

- **'IHS demand':** evolution of the total load based on the projection from 'IHS Markit', as used for the evaluation of the need for strategic reserves and initially proposed in the public consultation;
- **'Low demand':** evolution based on the WAM scenario from NECP for demand growth but with half the electrification of heat and transport compared to the 'CENTRAL' scenario.

Demand growth driven by economics and energy efficiency

Initially, the most recent forecast by 'IHS Markit', as used for the evaluation of the strategic reserves volume study, was proposed for the 'CENTRAL' scenario. After the comments received during the public consultation, it was decided to retain the WAM scenario from the draft NECP for the consumption growth in order to be fully aligned with the projections from Belgian authorities. It therefore includes the additional measures foreseen in the framework of the European energy efficiency targets for 2030. All information can be found in [NEC-1]. Using the draft NECP growth results in lower consumption than the initially proposed growth from 'IHS Markit' but has been kept as a sensitivity. The total electricity consumption used in the draft NECP is based on the EUROSTAT definition which doesn't include losses. For this reason, the evolution of DSO and TSO grid losses are added in the forecasting process.

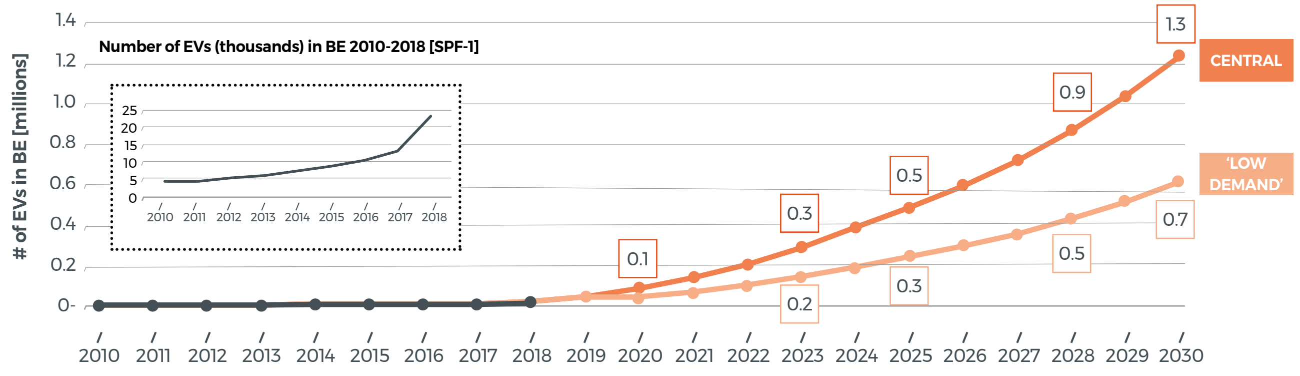
Additional electrification

Additional electrification (on top of the existing devices in 2015 already taken into account in the normalised and total consumption profile) was added by considering the consumption from additional electric vehicles (EVs) and heat pump (HPs) as defined in the NECP. Although no exact numbers of electric vehicles and heat pumps are provided in the draft NECP, assumptions were made to derive the number of EVs and HPs from additional electrification consumption foreseen. Figure 2-13 and Figure 2-14 summarise the expected evolution of electric vehicles and heat pumps until 2030 respectively for the 'CENTRAL' scenario (WAM scenario from draft NECP) and 'Low demand' scenario (considering half the amount of electric vehicles and heat pumps foreseen in the 'CENTRAL' scenario). More information on the draft NECP figures can be found here: [PLN-1].

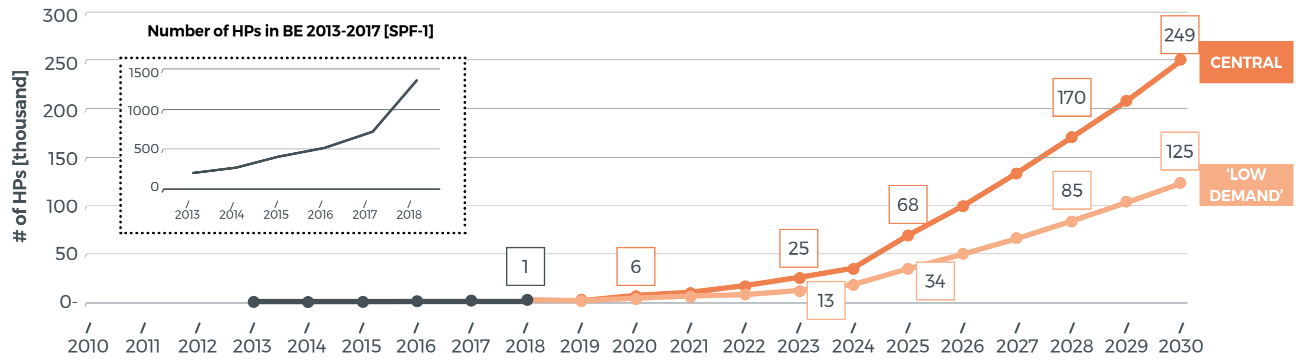
Thermosensitivity

Starting from the normalised hourly load profile (i.e. without thermo-sensitivity effect), thirty-four hourly load profiles are constructed by considering a large range of temperature conditions. Thirty-four historical daily temperature time series are used in the computation to provide an hourly load profile for each climatic year. This process is performed through the centralised tool TRAPUNTA used by ENTSO-E for European studies.

EVOLUTION OF THE NUMBER OF ELECTRIC VEHICLES PER SCENARIO IN BELGIUM [FIGURE 2-13]



EVOLUTION OF THE NUMBER OF HEAT PUMPS PER SCENARIO IN BELGIUM [FIGURE 2-14]



Resulting total consumption and peak load distribution for Belgium

Figure 2-15 gives an overview of the annual total demand since 2011 with its associated temperature-normalised value and the resulting total demand for the 'CENTRAL' scenario and the two sensitivities.

TOTAL LOAD EVOLUTION IN BELGIUM FOR EACH SCENARIO [FIGURE 2-15]

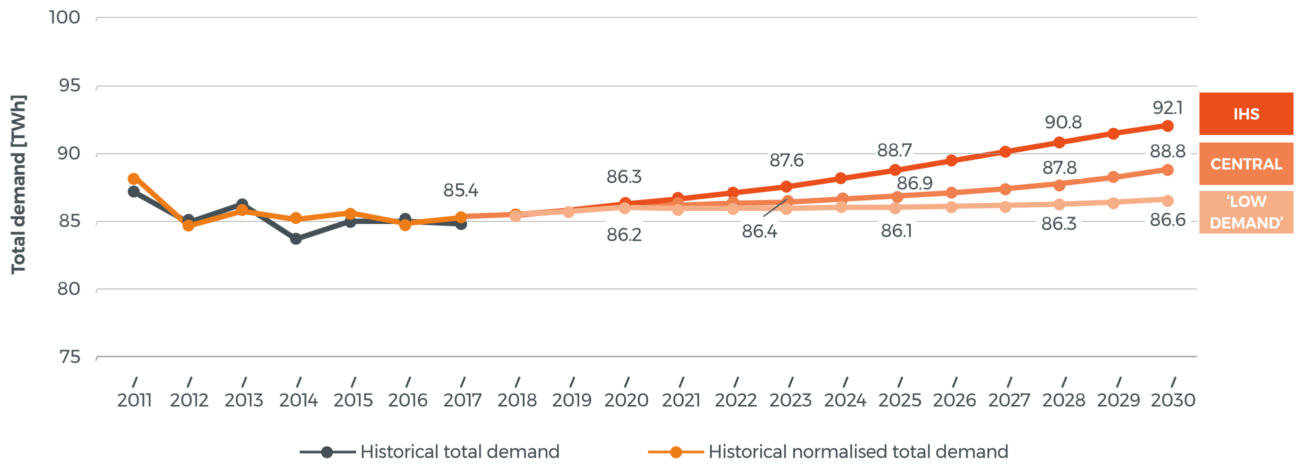
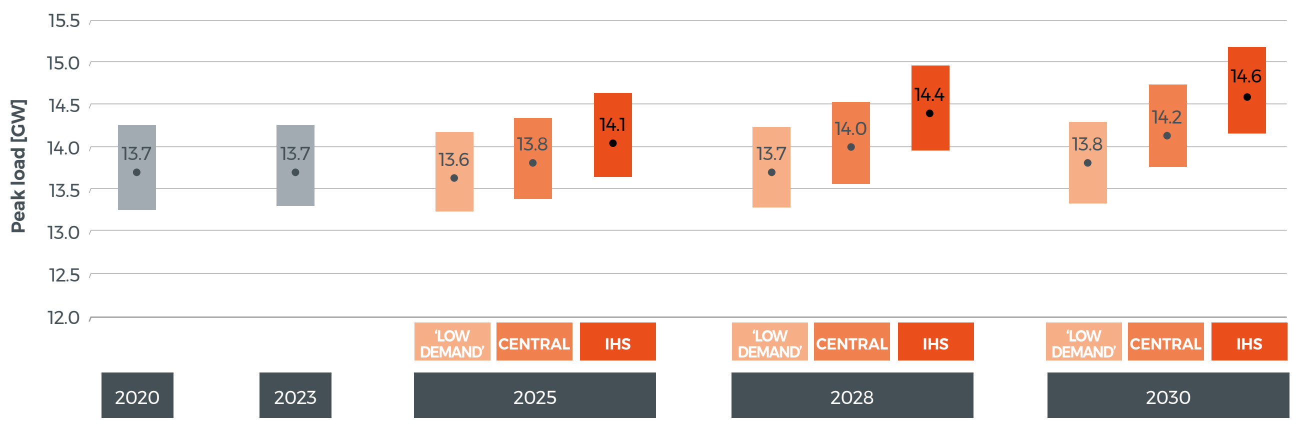


Figure 2-16 shows the peak load distribution over the different climate years for each scenario before applying any market response (shedding or shifting) and storage. The latter are economically dispatched by the model as described in Section 3.1.2.

PEAK LOAD EVOLUTION IN BELGIUM FOR EACH SCENARIO [FIGURE 2-16]



2.5.1.2. NUCLEAR GENERATION

The 'CENTRAL' scenario follows the current law regarding installed capacity from nuclear generation and assumes an unavailability of one third of the nuclear fleet such as observed in the past winters. A sensitivity is performed considering a 2 GW lifetime extension of the nuclear fleet after 2025 as requested by the stakeholders.

The hypothesis used in this study regarding installed capacity from nuclear generation is aligned with the law governing the nuclear phase-out [GOV-1], which has been amended twice:

- in 2013, with a 10-year lifetime extension of the Tihange 1 power plant (installed capacity of 962 MW);
- in June 2015, when the Belgian government decided that the Doel 1 and Doel 2 nuclear power plants (each with an installed capacity of 433 MW) could stay operational for an additional 10 years.

On this basis, the planned decommissioning date for each nuclear reactor is:

- **Doel 3:** 1st October 2022;
- **Tihange 2:** 1st February 2023;
- **Doel 1:** 15 February 2025;
- **Doel 4:** 1st July 2025;
- **Tihange 3:** 1st September 2025;
- **Tihange 1:** 1st October 2025;
- **Doel 2:** 1st December 2025.

BOX 6 : PAST AND FUTURE NUCLEAR AVAILABILITY

Since 2012, several events have impacted the nuclear generation fleet availability in Belgium. The following Figure 2-17 gives an overview of the available capacity per unit over the last ten years. It can be easily observed that from 2012 onwards, there were few periods when all the production fleet was available at the same time. Moreover, there were also periods where less than half of the fleet was available.

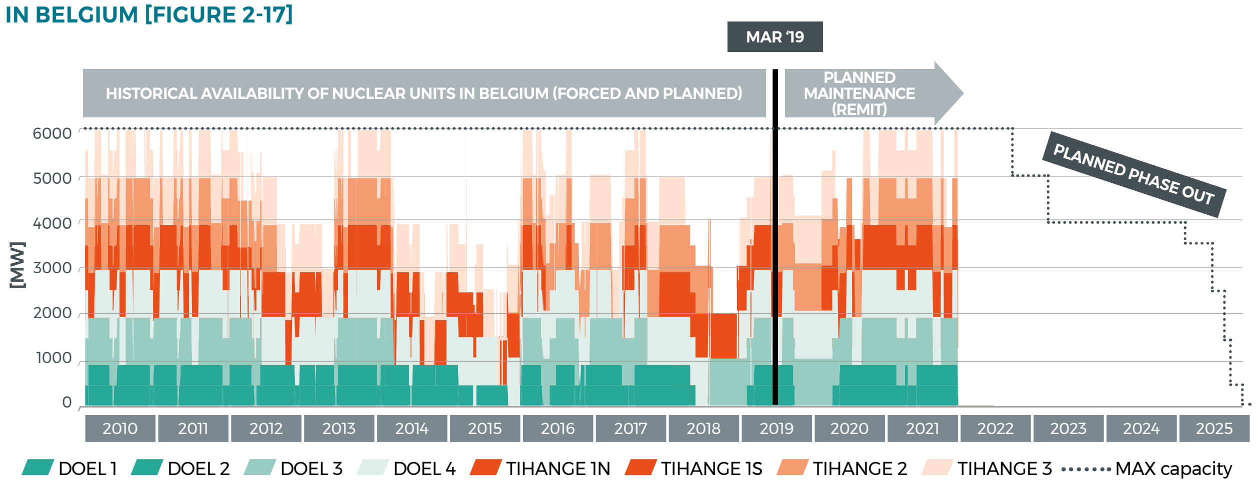
A non-exhaustive list of 'exceptional' events is provided below. Those events are to be considered on top of 'normal unavailability' due to forced outage or 'normal maintenance' that a unit has to comply with:

- Non conformity issues discovered during major overhauls or inspections. Such discoveries can lead to additional unavailability of one or more reactors (as some of them are based on the same technology) to perform additional analyses and, if required, to conduct the necessary repairs;
- Sabotage of parts of the installation. Such events are unpredictable and can lead to months of unavailability to repair the installation;
- Damages to certain parts after civil works;
- Prolongation works;
- New safety measures or tests to be performed.

Moreover, after the discovery or when the above events take place, it is sometimes hard to estimate the return dates of the nuclear units. Several months with intensive works are sometimes required which make it hard to estimate exactly when a unit will be back online.

With the increase of the safety measures and the ageing fleet, such events are not to be omitted when performing adequacy analyses. For a country such as Belgium, which nowadays relies on a large share of nuclear capacity, it is key to include a higher unavailability for those units than only the 'technical one'. This highlights the impact these events have on the country's adequacy. Recent history has also shown that those events are happening more often than in the past.

HISTORICAL NUCLEAR AVAILABILITY, FORECASTED AVAILABILITY (REMIT) AND NUCLEAR PHASE OUT IN BELGIUM [FIGURE 2-17]



Source: - Day ahead nominations for historical data
- REMIT data from ENGIE consulted end March 2019

The **'CENTRAL' scenario includes an unavailability of one third of the nuclear fleet** rounded to the unit above. This assumption was chosen to reflect the 'unexpected' events listed in BOX 6 and is in line with the so-called **'High Impact Low Probability'** scenario used to dimension the required volume of strategic reserve volume to respect the legal reliability standards for next winters, which is compliant with the **EC State Aid approval** for this mechanism [EUC-5].

The additional unavailability (on top of the technical outages) of nuclear units assumed in the 'CENTRAL' scenario is captured by removing a certain amount of capacity instead of applying higher outage rates (with low probability and long duration). Those events that are to be captured in the considered 'additional unavailability' are lasting much longer but have a very low probability of occurrence. Due to the major increase in the computational time required to perform such simulations, a certain capacity is removed from the simulation instead, leading to a similar effect. As this capacity is linked to the size of the units, it will not always be possible to ensure the same unavailability rate (e.g in the 'nuclear extension sensitivity'). In such case, the amount of units to be set as 'unavailable' will be chosen to at least cover the required unavailability of one third of the capacity.

The following unavailability of the nuclear generation fleet is taken into account:

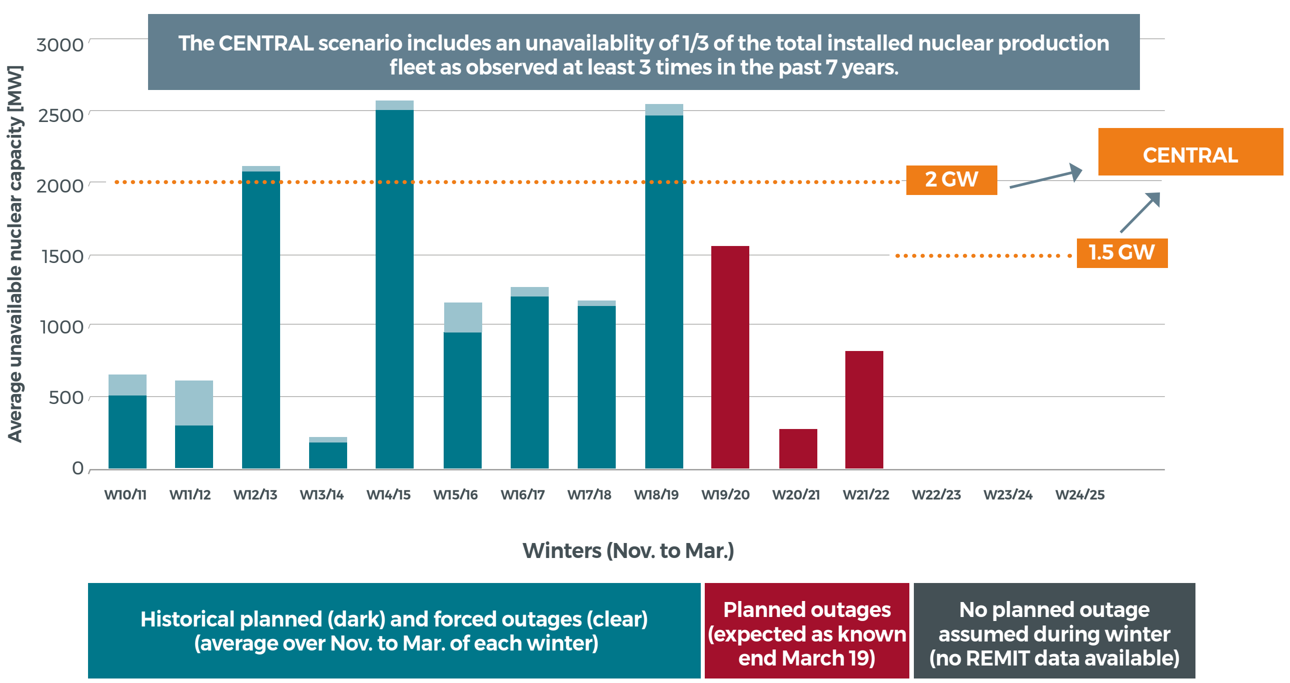
- Winter 2020-21: 2 GW unavailability in total (including already planned outages (REMIT) such as shown in Figure 2-18. and a forced outage rate of 3.5%);
- Winter 2023-24: 1.5 GW unavailability in total (including a forced outage rate of 3.5%);
- Winter 2025-26: no additional unavailabilities considered (only a forced outage rate of 3.5% for the remaining capacity until 1st December 2025).

The number of units considered as unavailable in the 'CENTRAL' scenario is in line with the strategic reserve volume evaluation scenario of November 2018 where 1.5 GW is considered unavailable (on top of the already planned maintenance of 500 MW) which resulted in a total unavailability of 2 GW in this assessment. More information can be found on page 130, Section 6.3 of the latest SR report [ELI-13].

Finally, as suggested by some stakeholders, a sensitivity with a 2 GW (2 units) nuclear lifetime extension for the next 10 years was also assessed. In this sensitivity, 1 unit will be considered as unavailable (out of the 2) which corresponds to the minimum amount of units to satisfy one third of unavailability of the nuclear production fleet (≈700 MW).

It is also important to mention that extending the lifetime of nuclear reactors would also lead to prolongation works. Given the high safety standards and the possible works required (as mentioned in BOX 6), those could lead to long lasting unavailabilities prior to the currently planned phase out or during the first years of the lifetime extension. In this study, the effect of this potential extra unavailability has not been further assessed in a quantitative way.

HISTORICAL UNAVAILABILITY OF NUCLEAR UNITS DURING WINTER, PLANNED UNAVAILABILITY AND SIMULATED UNAVAILABILITY [FIGURE 2-18]



2.5.1.3. RENEWABLES

The 'CENTRAL' scenario follows the draft NECP (WAM scenario) installed capacities for Belgium.

A sensitivity with a higher and lower growth will be applied to assess the impact on the needed volume as requested by the stakeholders.

For the public consultation, the values from the 'Energy Pact' were initially proposed for the 'CENTRAL' scenario. Following the questions from stakeholders, the values were changed to be fully aligned with the draft NECP - WAM scenario. Specifically, 3 GW of PV were added in total for the year 2030 and 300 MW of biomass was removed for the same year.

As requested by the stakeholders, a sensitivity with higher and lower RES penetration compared to the 'CENTRAL' scenario was simulated:

- **'High RES':** higher penetration of onshore wind and solar capacity in Belgium. The commissioning of the second wave of offshore wind is also accelerated;
- **'Low RES':** lower penetration of onshore wind and solar capacity in Belgium compared to the CENTRAL scenario. Offshore wind capacity follows the same assumption as in the CENTRAL scenario.

The underlying assumptions for these sensitivities are described below for each technology.

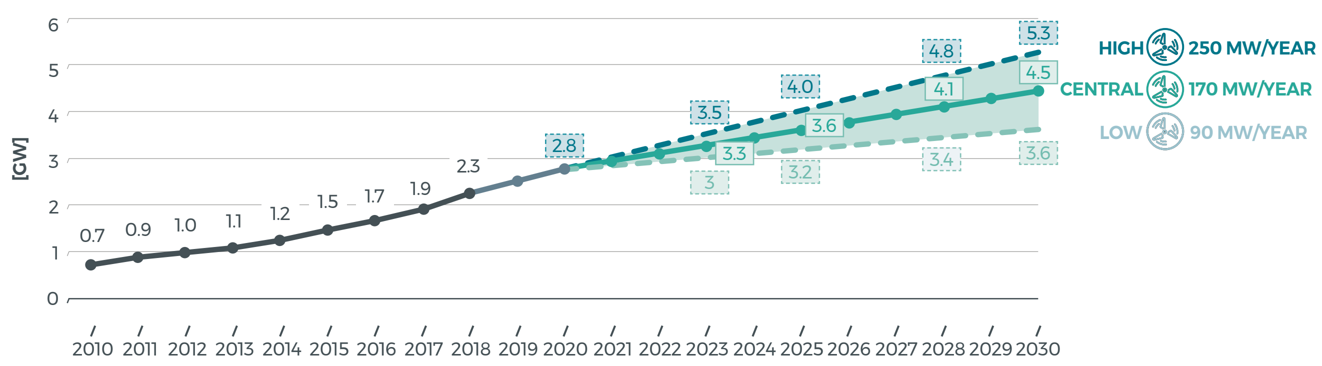
Onshore wind

Figure 2-19 shows the historical increase in installed capacity for onshore wind generation and the evolution foreseen in the WAM scenario from the draft NECP. This basis is used as the reference for the 'CENTRAL' scenario. The average forecasted development amounts to an increase of approximately **170 MW per year** in the 'CENTRAL' scenario reaching **4.5 GW in 2030**.

Two sensitivities are applied on this evolution:

- In the **'High RES'** scenario, the onshore capacity grows by **250 MW per year** reaching **5.3 GW in 2030**;
- In the **'Low RES'** scenario, the growth of onshore capacity is limited to **90 MW per year** reaching **3.6 GW in 2030**.

EVOLUTION OF INSTALLED ONSHORE CAPACITY PER SCENARIO IN BELGIUM (AT THE END OF THE MENTIONED YEAR) [FIGURE 2-19]

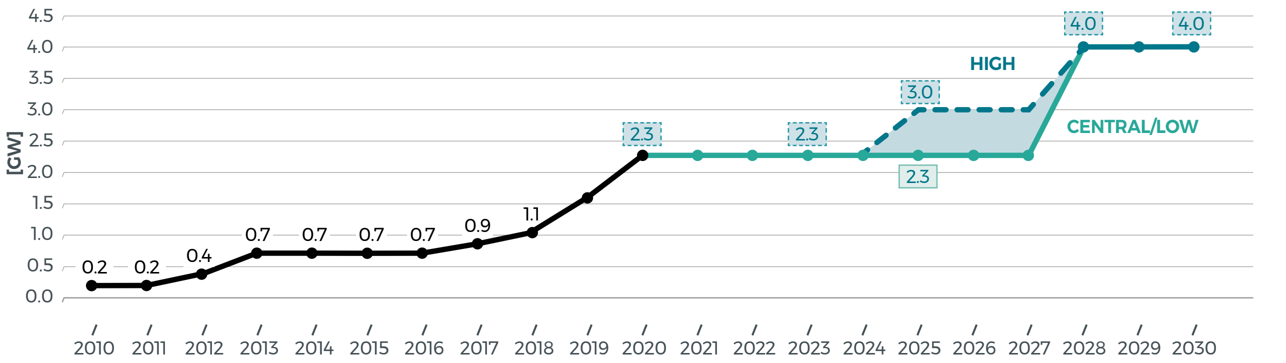


Offshore wind

Figure 2-20 shows the historical increase in the installed capacity of offshore wind and the forecasted installed capacity considered in this study. The installed offshore wind capacity is expected to reach around 2.3 GW by mid-2020 according to the latest planning of offshore concessions and up to 4 GW before the end of 2028 with the 'second offshore wave'. This forecast is aligned with the draft NECP.

In the **'High RES'** scenario, the 'second offshore wave' starts commissioning earlier with 700 MW by 2025. This would lead to 3 GW installed offshore wind capacity for 2025. The installed capacities for the other years studied are kept at a similar level for the different scenarios.

EVOLUTION OF INSTALLED OFFSHORE CAPACITY PER SCENARIO IN BELGIUM (AT THE END OF THE MENTIONED YEAR) [FIGURE 2-20]

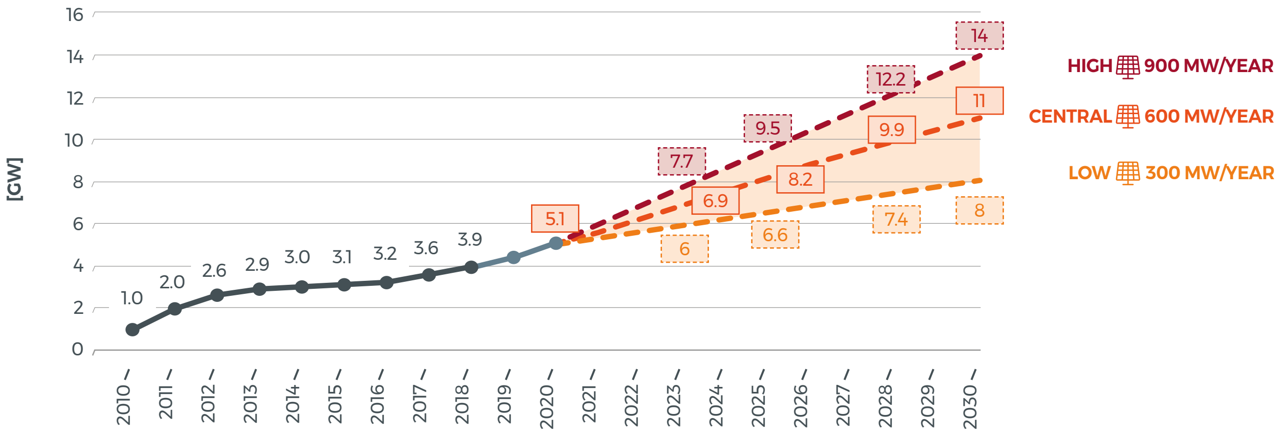


Solar

Figure 2-21 shows the historical increase in installed capacity from photovoltaic (PV) generation in Belgium and the projection used in this analysis, which was based on the forecast defined by the regions in the draft NECP. The average increase amounts to **600 MW per year** in the '**CENTRAL**' scenario leading to **11 GW in 2030**. Two sensitivities are applied on this projection:

- In the **'High RES'** scenario, the growth rate of the CENTRAL scenario is doubled: PV grows by **900 MW per year** reaching **14 GW in 2030**;
- In the **'Low RES'** scenario, the growth rate of the CENTRAL scenario is halved down to **300 MW per year**, which leads to **8 GW** of installed PV capacity **in 2030**.

EVOLUTION OF INSTALLED SOLAR CAPACITY PER SCENARIO IN BELGIUM (AT THE END OF THE MENTIONED YEAR [FIGURE 2-21]



Run-of-river hydro

The potential for run-of-river hydro is limited in Belgium. The draft NECP (WAM scenario) foresees a slight increase of run-of-river capacity in the WAM scenario going from 123 MW in 2020 to 151 MW in 2030. A linear interpolation is applied for time horizons between 2020 and 2030.

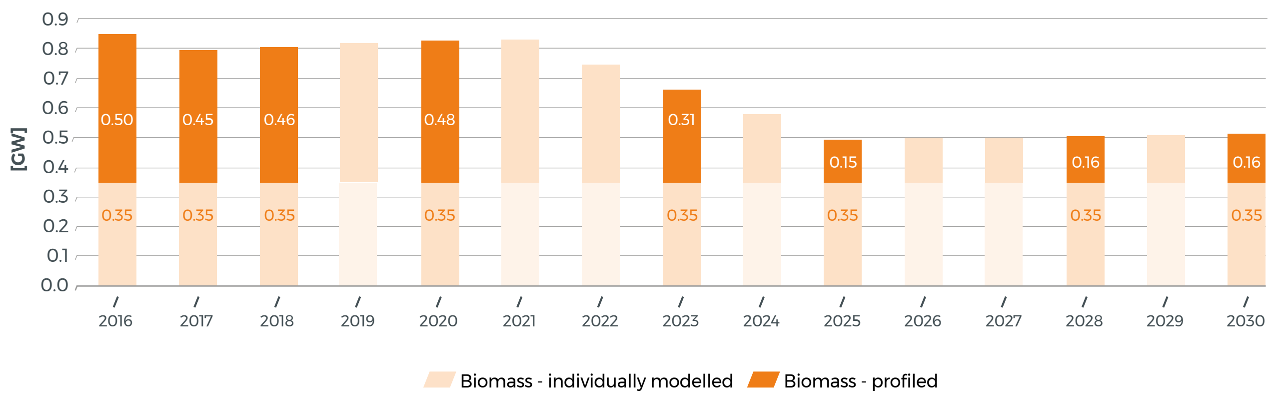
Biomass

Figure 2-22 shows the evolution foreseen in the WAM scenario from the draft NECP for biomass units. For modelling purposes, there is a need to distinguish the 'large' units which are individually modelled (with an associated forced outage) and the 'smaller' units which are taken into account with an historical average generation profile.

In order to perform this split, Elia maintains a database of centralised and decentralised generation units, which is updated on a monthly basis following exchanges with DSOs and grid users directly connected to the Elia grid. The database includes both units with and without a CIPU[1] contract:

- The biomass units with CIPU contracts are modelled individually with historical availability rates. In the model, these units are set as 'must run', i.e. they operate baseload given support mechanisms or following other specific requirements (heat, demand, ...). The installed capacity is kept constant until 2030 (348 MW);
- The non-CIPU biomass units are taken into account by the model through hourly normalised profiles. These time series are constructed on the basis of available historical data. The installed biomass capacity forecasted by the regions in the draft NECP is assumed to decrease until 2025 (-31% compared to 2021) and to remain relatively stable after 2025.

EVOLUTION OF INSTALLED CIPU AND NON-CIPU BIOMASS CAPACITY IN BELGIUM (AT THE END OF THE MENTIONED YEAR) [FIGURE 2-22]



2.5.1.4. WASTE

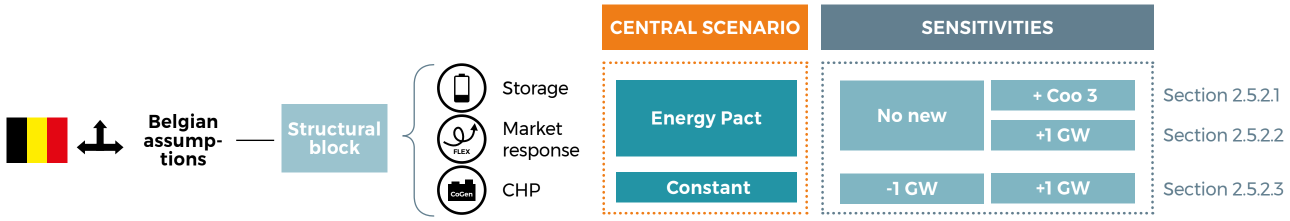
As for biomass capacity, the installed waste capacity in Belgium is based on a database of centralised and decentralised generation units maintained by Elia. The same modelling used for biomass capacity is also applied for waste units:

- The waste units with CIPU contracts are modelled in the same way as the biomass CIPU category. The installed capacity is kept constant until 2030 (268 MW);
- The non-CIPU waste units are taken into account by the model through hourly normalised profiles in the same way as for non-CIPU biomass. The installed waste capacity is kept constant until 2030 (46 MW).

Note that some of the waste capacity is also considered as renewable. As proposed in the public consultation (and as no comments or counter proposals on this evolution were received), the capacity is assumed constant after 2020.

1. 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.

2.5.2. Structural block



The 'structural block' consists of all the other capacities not yet described in Section 2.5.1. One could argue that some of the technologies considered in the 'structural block' could also be considered as policy driven given existing or future support schemes (if any) although most of the capacity can be assumed as market driven. More information regarding structural block definition can be found in Section 3.1.1.

2.5.2.1. STORAGE

The 'CENTRAL' scenario considers the existing pumped-storage facilities with an increase of the COO reservoir by 400 GWh from 2021 and capacity by 87 MW from 2024.

In addition, based on the 'Energy Pact', new storage in the form of small and large scale units and 'Vehicle-to-Grid' is considered for an amount totalling 1 GW by 2025 and 1.6 GW by 2030.

A sensitivity with no new storage facilities will be performed to assess the impact on the required volume to be adequate.

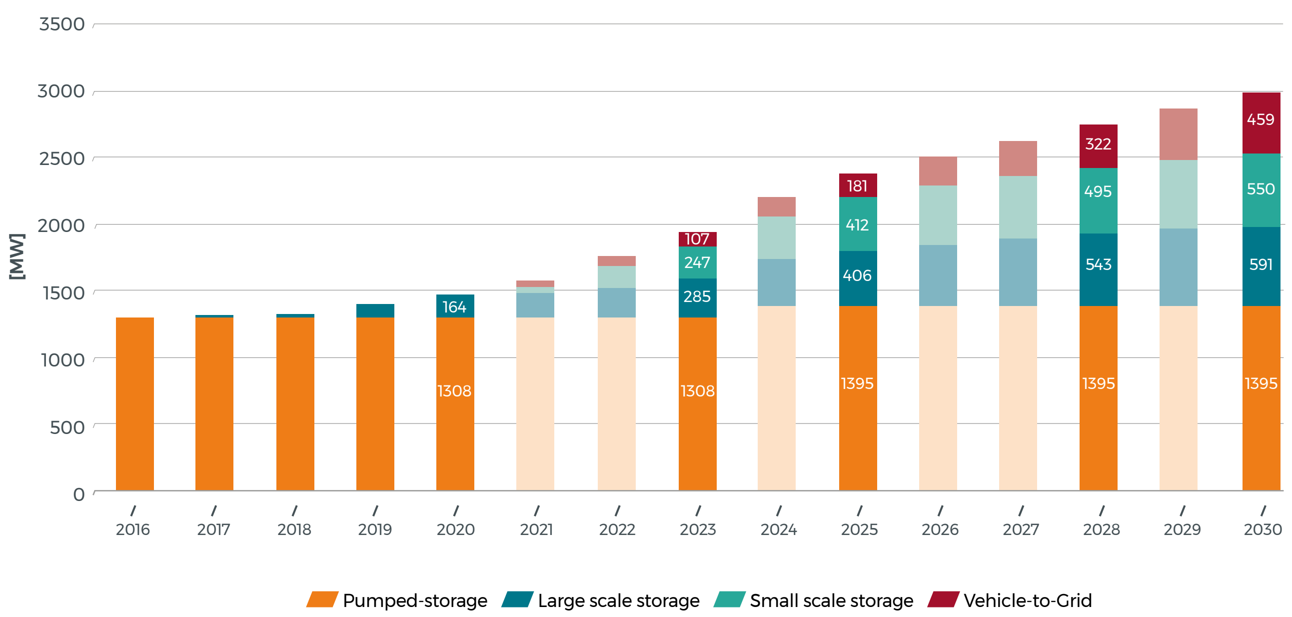
A sensitivity with an additional pumped-storage unit of 600 MW (with a proportional increase of the current reservoir in Belgium) will also be assessed.

This study considers 4 types of storage facilities:

1. Existing pumped-storage facilities (with an increase of the COO reservoir by 400 GWh from 2021 and capacity by 87 MW from 2024);
2. Large scale batteries (>100 kW), installed nowadays to provide ancillary services;
3. Small scale batteries (<100 kW), usually called 'home batteries';
4. Electric vehicles' batteries operating in 'Vehicle-to-Grid' (V2G) mode.

The total future storage capacity (in the form of small or large scale units and V2G) is based on the target set by the 'Energy Pact' leading to 1.6 GW in 2030 (excluding pumped-storage). Although the total power capacity is mentioned in the 'Energy Pact', no breakdown nor a reservoir capacity is provided. For this reason, additional assumptions have been made to split the total capacity set by the 'Energy Pact' for large/small scale batteries and V2G batteries. Those assumptions are explained below. Figure 2-23 shows the evolution of storage facilities included in this study.

EVOLUTION OF INSTALLED CAPACITY OF 'OTHER STORAGE FACILITIES' IN THE CENTRAL SCENARIO [FIGURE 2-23]



Pumped-storage

The operating cycles of pumped-storage units are optimised by the model, which determines the ideal moment to use those units based on the hourly price (i.e. economic dispatch). In order to consider the limited energy that can be stored, a reservoir volume is associated with each unit.

The current installed capacity of **1.3 GW** pumped-storage in Belgium (Coo 1 & 2 and Plate Taille) is considered in this study. The dispatchable reservoir volume is 5.3 GWh (5.8 GWh where 0.5 GWh is considered to be reserved for black start services). Additionally, an increase of the Coo reservoir to 5.7 GWh (i.e. 7.5%) from 2022 and Coo capacity to 1.4 GW (i.e. 7.5% as well) from 2025 is taken into account.

A **sensitivity** on storage facilities is considered in this study by considering **a new unit of 600 MW in Coo ('Coo 3')**. The total reservoir size was increased proportionally to 8.1 GWh.

Given the limited reservoir size of pumped-storage units in Belgium, they usually follow daily cycles: the reservoirs are filled during the night in order to be able to compensate for the peak demand occurring during the day. This cycle could change in the future with larger penetrations of PV installations where it could be more interesting to pump energy during the day (when PV is producing the most). This is taken into account in the model with the economic optimisation of the storage facilities. A roundtrip efficiency of 75% is considered.

Vehicle-to-Grid

A part of the electric vehicle fleet is assumed to allow bidirectional flows between the vehicle batteries and the grid, so-called 'Vehicle-to-Grid' (V2G). Those vehicles – when connected to the power grid – can store or release energy based on different signals. Energy can therefore be stored in the vehicle batteries and released at a later stage. The following set of characteristics were considered to determine the usable storage capacity of the vehicles:

- 5% of the electric vehicle fleet is continuously connected to the grid and is able to operate in V2G mode (and has a specific installation for it);
- Chargers of around 7 kW;
- 4 hours storage capacity (assuming 50% of the battery size can be used for V2G and a mean value of a vehicle battery of 60kWh). Today the mean battery size is around 35 kWh but the arrival of premium models in the market could bring the mean to around 60 kWh in the future [CLT-1].

On this basis, the total capacity for V2G reaches 0.18 GW (with 0.73 GWh of reservoir) in 2025 and 0.46 GW (with 1.84 GWh of reservoir) in 2030.

Small scale batteries

The penetration of small scale batteries (i.e. residential/home batteries) is based on foreseen PV installations. It was assumed that from 2021 onwards 5% of total installed solar capacity will be combined with small scale batteries with 1 kWh storage for 1kW PV.

The following characteristics are considered:

- Those batteries are assumed to have an energy content of 3h (based on current and future expected average battery sizes)[TES-1];
- A roundtrip efficiency of 90%;
- No limitations in terms of the amount of charge/discharge cycles (the utilisation is only limited by the available energy in the battery at a given time).

On this basis, the total capacity for small scale batteries reaches 0.41 GW (with 1.23 GWh of storage reservoir) in 2025 and 0.55 GW (with 1.65 GWh of reservoir) in 2030.

Large scale batteries

Finally, the large scale batteries are quantified based on the total capacity defined by the 'Energy Pact' from which V2G and small scale battery capacity was deducted.

The following characteristics are considered:

- Those batteries are assumed to have an energy content of 1h (based on current and future projects' expected average battery size);
- A roundtrip efficiency of 90%;
- No limitations in terms of the amount of charge/discharge cycles (the utilisation is only limited by the available energy in the battery at a given time).

On this basis, the total capacity for large scale batteries reaches 0.41 GW (with 0.41 GWh of reservoir) in 2025 and 0.59 GW (with 0.59 GWh of reservoir) in 2030.

2.5.2.2. MARKET RESPONSE

The 'CENTRAL' scenario considers all existing market response volumes based on the annual historical analysis performed in the framework of the strategic reserve volume evaluation, including the volume participating in the ancillary services.

On top of the existing volumes in 2018, an additional 1.3 GW is considered for market response in the form of 'shedding' and 1.5 GWh in the form of 'shifting' for 2030, based on the 'Energy Pact' figures.

A sensitivity is performed with an additional volume of 1 GW from 2025.

A sensitivity is performed considering no additional volumes on top of existing ones for the future.

Market response is a crucial dynamic parameter when difficult situations occur on the electricity grid, especially under demanding conditions when adequacy problems arise. European policy makers (2009/72/EC and 2012/27/EC), national politicians and regulators are all striving towards the further development of market response (MR).

This study takes into account market response reacting to price signals through **shedding and shifting**. The market response contracted for ancillary services is also modelled in order to take into account its participation in the needed flexibility options to balance the grid. Market response volumes can be considered as distributed capacity that can be activated when prices rise above a certain level and for a limited time duration (depending on several constraints). These include shedding and shifting of consumption, storage and even small scale generators (those not explicitly taken into account as generation units in the model such as emergency generators). In this study, storage capacities are nevertheless considered in a separate category.

For this study, as the goal is to assess whether the system can cope with the adequacy and total flexibility requirements, no distinction is made between flexibility provided through the TSO (i.e. ancillary services) and flexibility provided through the market (i.e. as market response). In the 'strategic reserve volume' study, only the market response participating in the energy market was modelled because the volumes contracted for balancing services were assumed to be unavailable for the day-ahead market. In this study, the market response is complemented with the balancing capacity volumes (ancillary services) procured by Elia from decentral capacity. These contribute both to adequacy and flexibility.

As for all other technologies, the 'CENTRAL scenario' is based on the ambitions set in the draft NECP and the 'Energy Pact'. In the latter, the authorities have set fixed targets/ambitions for market response for 2030 and these are used for the 'CENTRAL scenario' as described in the section below. Sensitivities on these assumptions are performed. Note that the model can also invest in new market response if viable (see Section 3.2. for more information).

Shedding

Shedding is realised by grid users that can reduce part of their consumption when prices reach a certain level (called the 'activation price'). This can also be realised by activating emergency generators.

The Energy Pact also mentioned that the main increase will happen after 2025 (i.e. from **2025** to **2030** for this study), with around 30% to 40% of the target achieved in 2025.

On this basis, the market response volumes for the CENTRAL scenario in 2025 and 2030 are set with:

- 1.6 GW in **2025** (including 565 MW for ancillary services, see below);
- 2.6 GW in **2030** (including 565 MW for ancillary services, see below).

Note that it is also assumed that the volumes proposed in the 'Energy Pact' do not include the market response participating today in the ancillary services (which is around 470 MW for winter 2017-18). This latter volume is added to the targets set by authorities following the projection from E-CUBE study and additional assumption for volume after 2021:

- 535 MW of ancillary services volume for 2020;
- 565 MW of ancillary services volume from 2021 and kept constant for all next years.

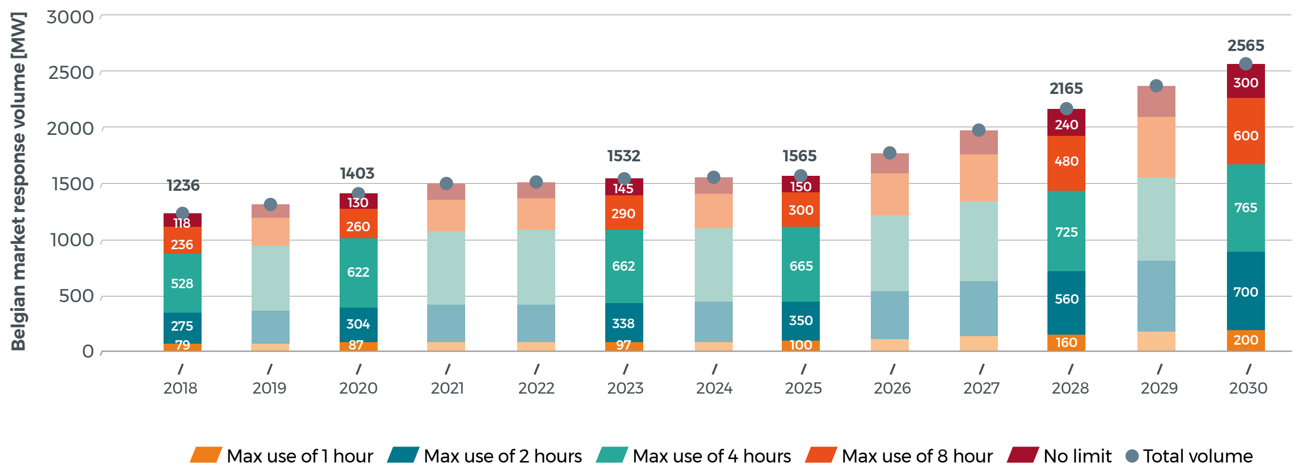
For the **forecasts before 2025**, the 'E-Cube study' [ELI-10], i.e. the latest market response evaluation study conducted in 2018 for the Strategic Reserves evaluation, is only used for 2020-21 and to make the linear interpolation between the first 3 years and 2025.

In 2020, a market response capacity of 1403 MW is assumed (extrapolation of market response capacity following the 'E-Cube study'), which is expected to include an ancillary service volume of 535 MW (estimation used in the current market response study for 2020).

It was chosen to allocate the capacities over five categories with the only distinction being the amount of energy that can be allocated per day (expressed in amount of hours). This is different from the seven categories from the 'E-Cube study' where both weekly and duration constraints are defined (see Figure 2-24 below). The seven categories from the 'E-Cube study' are reduced to five categories for this study by taking the number of activations per week into account and underlying activation duration translated into equivalent energy per day (i.e. max use of 1 hour, 2 hours, 4 hours, 8 hours and no limit). An activation price between 300 and 2000 €/MWh is considered.

The capacity of ancillary services is added to the 4-hour duration category, as this corresponds with the current products of ancillary services resulting in a share of 86% (535 MW of ancillary services volume on 622 MW of 4-hour duration category) in 2020, going to a share of 74% (565 MW of ancillary services volume on 765 MW of 4-hour duration category) in 2030 (as the capacity of market response grows in this category while the 565 MW is kept constant).

BELGIAN MARKET RESPONSE VOLUME SHEDDING (INCLUDING THE ONE PARTICIPATING IN THE ANCILLARY SERVICES TODAY) [FIGURE 2-24]



Shifting

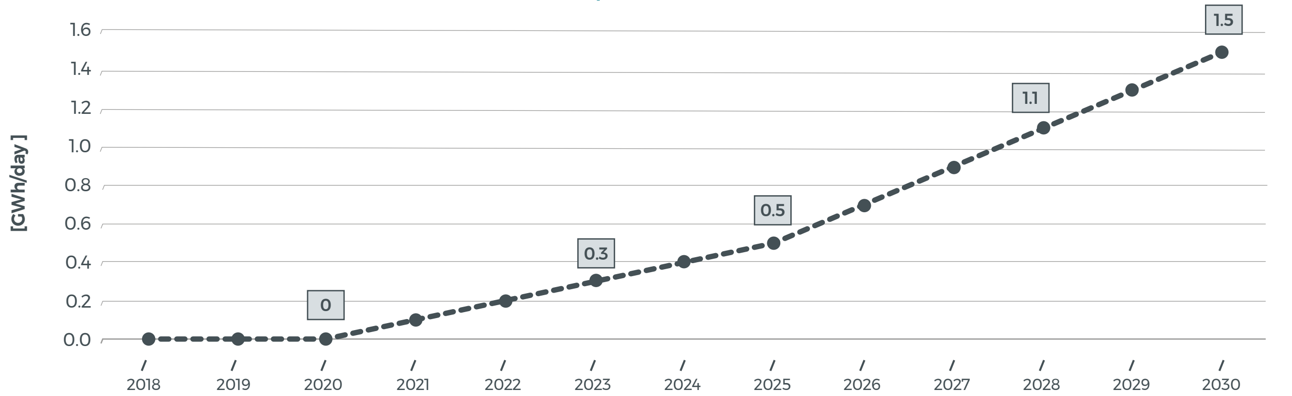
Load shifting consists of consumption that can be moved to another moment within the day (unique requirement set in the model). This kind of flexibility option can be used to optimise the consumption profile in relation to electricity prices or other signals.

Based on the 'Energy Pact', the demand shifting volume for the CENTRAL scenario in **2025** and **2030** is set with:

- 0.5 GWh in **2025**;
- 1.5 GWh in **2030**.

As for shedding, the 'Energy Pact' indicates that the main increase takes place after 2025 (i.e. from 2025 to 2030 for this study) as shown in Figure 2-25.

TOTAL MARKET RESPONSE SHIFTING VOLUME [GWH/DAY] [FIGURE 2-25]



SCENARIOS AND ASSUMPTIONS

2.5.2.3. FOSSIL FUEL GENERATION

The 'CENTRAL' scenario considers all existing units unless their closure has been announced (CHP, CCGT, OCGT, turbojets, ...)

An economic viability check is performed to assess which of these capacities would remain available in the future based on their market revenues.

As requested by stakeholders, a sensitivity with higher and lower values for installed CHP capacity will be considered.

No maintenance for those units is applied during winter months.

The fossil fuel generation is consisting of:

- Combined heat and power (CHP) units with CIPU contract (individually modelled) and without CIPU contract (modelled through hourly normalised profiles);
- Existing CCGT and OCGT units;
- Existing turbojets.

For the individually modelled units (i.e. CHP with CIPU contract, existing CCGT and OCGT units and existing turbojets), a draw on the availability is performed based on their outage characteristics. This is described in greater detail in Section 2.5.3.

Installed CHP capacity

As for biomass and waste capacity, the installed CHP capacity in Belgium is based on a database of centralised and decentralised generation units maintained by Elia. The same modelling for biomass/waste capacity is applied for CHP units:

- The CHP units with CIPU contracts are modelled in the same way as the biomass CIPU category. Those units are modelled with a partial must-run associated to a marginal price being 20% lower than new CCGTs;
- Based on a suggestion during the public consultation, it was decided to include Zandvliet Power (384 MW) and Inesco (138 MW) in a separate category (CCGT-CHP) to reflect their ability to operate in CHP mode. Those units follow the same characteristics as CCGTs;
- The installed capacity for CIPU CHP is kept constant until 2030 with a volume of 1337 MW (i.e. including Zandvliet Power and Inesco);
- The non-CIPU CHP units are taken into account by the model through hourly normalised profiles. The installed CHP capacity is kept constant until 2030 (1244 MW).

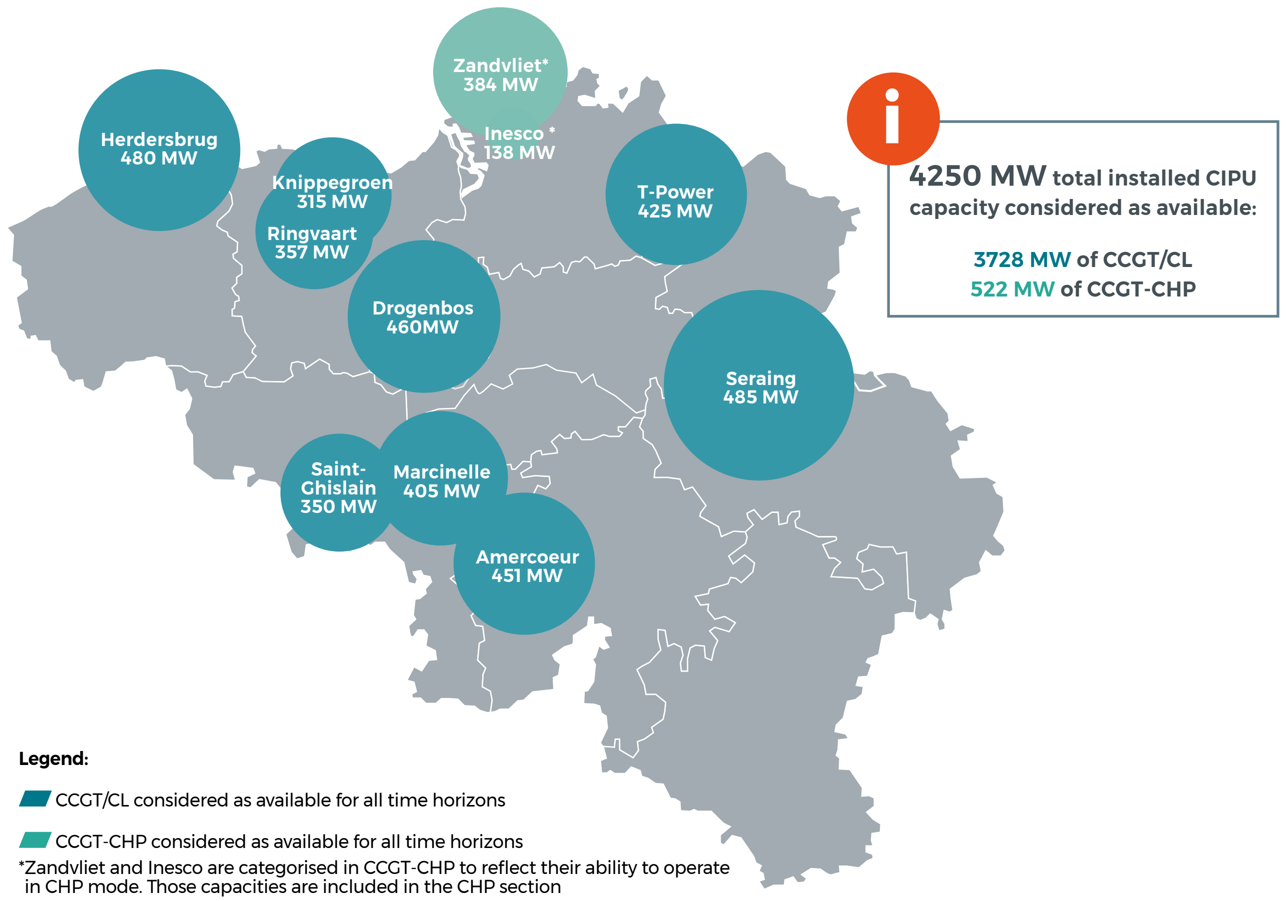
As requested by stakeholders, a sensitivity with higher (+1GW) and lower (-1GW) CHP capacity is considered, cf. Section 4.1.3 for more information.

Installed capacity of CCGT/Classical, OCGT and turbojet units

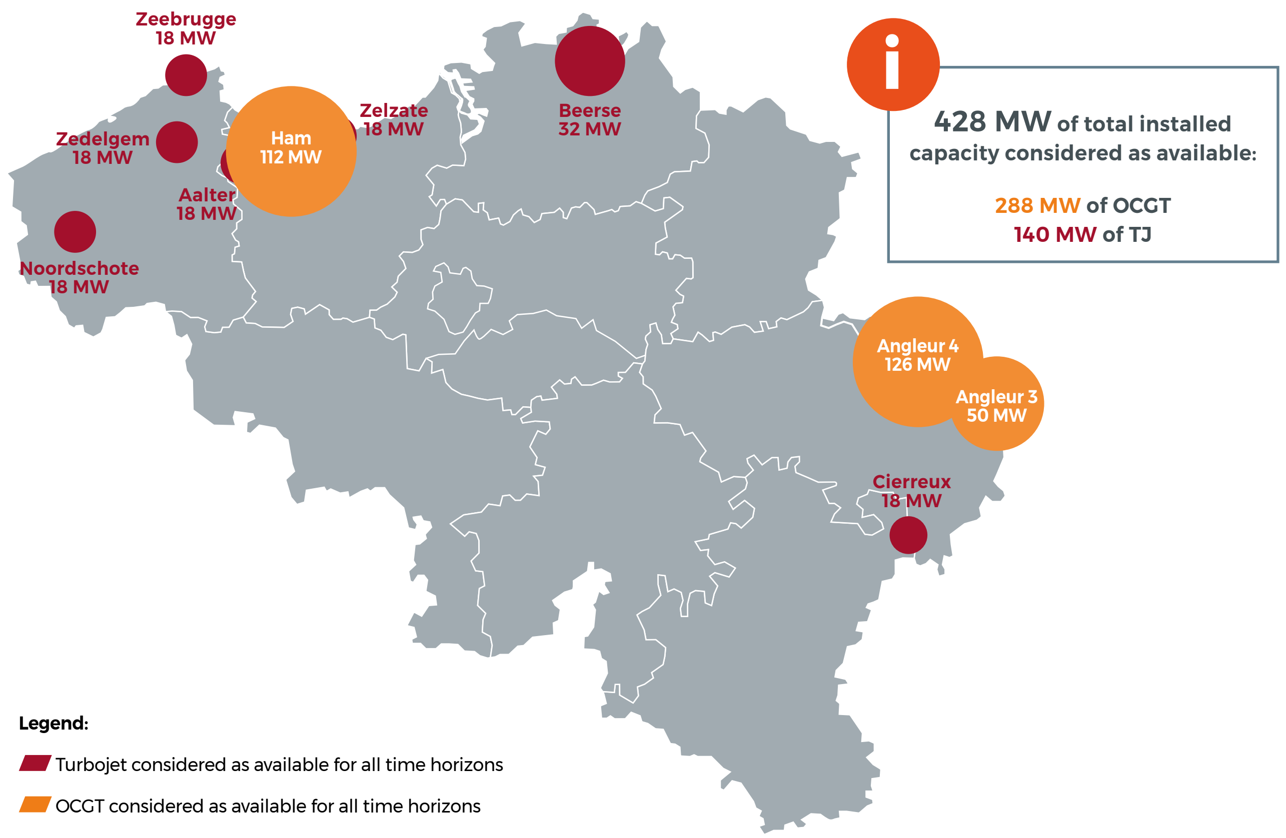
The installed capacity of Belgian thermal generation units covered by a CIPU contract is consolidated during summer by Elia and the FPS Economy based on information submitted by producers to the federal Minister for energy, the FPS Economy, CREG and Elia, as stipulated in the Electricity Law. The latter parties cannot be held accountable for actually realising the hypothetical volumes, as this is the producers' responsibility. Figure 2-26 shows the generation units covered by a CIPU contract and considered in this study. The status of each unit was updated with the information known on 1st April 2019.

For illustrative purposes, the geographical distribution of CCGT, classical (CL) and CCGT-CHP in Belgium is shown in Figure 2-26 and the same for OCGT and turbojets in Figure 2-27.

TOTAL INSTALLED CCGT/CCGT-CHP/CL CAPACITY AVAILABLE IN BELGIUM [FIGURE 2-26]



TOTAL INSTALLED OCGT AND TURBOJET CAPACITY AVAILABLE IN BELGIUM [FIGURE 2-27]



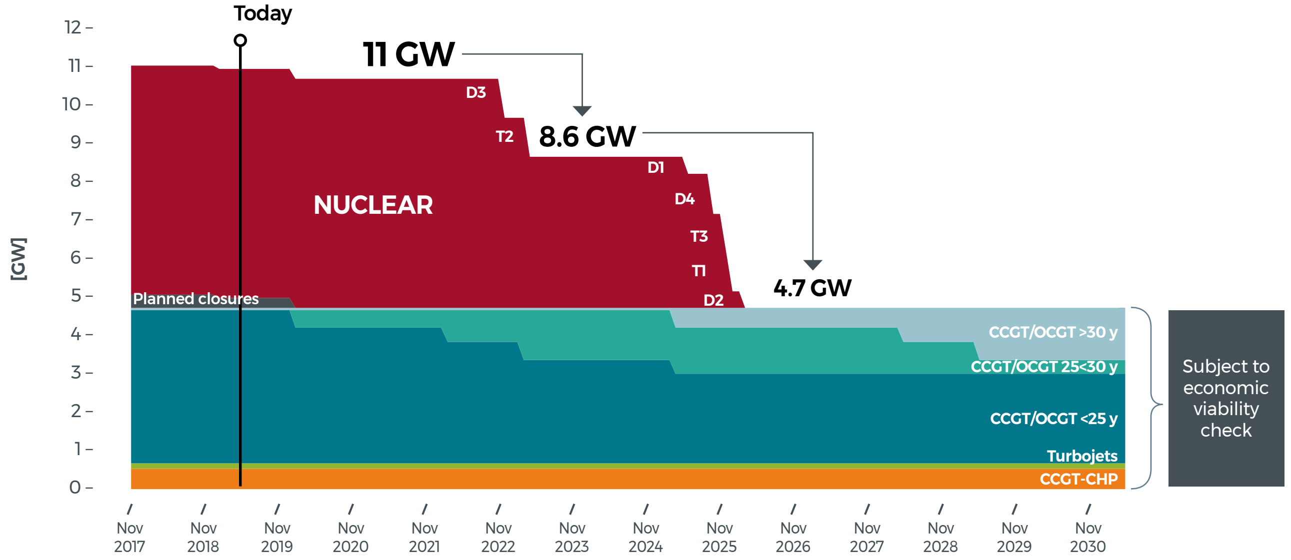
The complete list of existing units can be found in the Excel file published in attachment to this report on the Elia website.

All those thermal units can be part of the structural block and can contribute to it by considering their economic viability. On top of those units, new built CHP, CCGT and OCGT (if needed) will also be considered when the assumed volumes in all other technologies would not be sufficient to meet adequacy requirements, while also considering an economic viability check.

For the economic viability check, a distinction will be made between units below 25 years of operation and above. It will be assumed that the first ones do not require refurbishment costs. The second ones will be considered to require such costs. Figure 2-28 illustrates the distribution of age for CCGT, OCGT and CCGT-CHP thermal units for the different time horizons (i.e. excluding turbojet units). Note that the installed capacity is the one available at the end of each year.

Note that (as suggested by the CREG during one of the working group meetings with FPS Economy and FPB) the CCGT unit Seraing was considered in the first category (<25 years) for the whole horizon given that the refurbishment of the unit happened in 2008.

INSTALLED THERMAL CAPACITY IN BELGIUM (EXCLUDING CHP AND BIOMASS) [FIGURE 2-28]



2.5.2.4. NEW CAPACITY OF ANY KIND TO FILL THE IDENTIFIED NEED

Depending on the adequacy results (see Chapter 4) and the economic viability check (see Section 4.2), the identified structural block can be filled by new technologies such as:

- New CHP;
- New storage;
- New market response (shedding, shifting, emergency generators);
- New diesel generators/turbojets/gas engines;
- New CCGT/OCGT.

The process followed to invest in new technologies in the structural block is described in Section 3.1.1.

2.5.3 Forced outage characteristics

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 2007-2017 and using the availability for generation units nominated in the day-ahead market. The available public data from ENTSO-E Transparency Data were used for historical years when available (i.e. only for 2015-2017 period), more info can be found here: [ENT-3].

TABLE 1: FORCED OUTAGE PROBABILITIES

OUTAGE RATE	NUMBER OF FORCED OUTAGES PER YEAR	AVERAGE FORCED OUTAGE RATE OVER 2007-2017 [%]	AVERAGE DURATION OF FORCED OUTAGE RATE (2007-2017)
Nuclear	1.6	3.5%	7 days - 171 hours
Classical	6.1	7.9%	3 days - 83 hours
CCGT	5.2	8.9%	4 days - 97 hours
GT	2.8	12.3%	6 days - 133 hours
TJ	2.2	4.3%	4 days - 105 hours
Waste	1.3	1.5%	3 days - 72 hours
CHP	3.5	6.4%	5 days - 111 hours
Pumped storage	1.9	4.3%	6 days - 141 hours
NEMO-Link (in each direction)	2	5%	7 days - 168 hours

3 DIFFERENT OUTAGE PARAMETERS ARE NEEDED FOR THE CURRENT STUDY:

The definitions of the first two parameters are used in adequacy studies and are in line with the ENTSO-E methodology. The third one is only used for the flexibility assessment.

1. The forced outage rate (used for the adequacy assessment)

This consists of the amount of unavailable energy due to forced outage (FO) divided by all the other moments when the unit was available and in forced outage.

$$\text{Average FO rate} = \frac{\text{FO energy } 2007\rightarrow 2017}{\text{FO energy } 2007\rightarrow 2017 + \text{Available energy } 2007\rightarrow 2017}$$

2. The average forced outage duration (used for adequacy and flexibility assessment)

This is the average length of a forced outage (FO)

$$\text{Average FO duration} = \frac{\text{Average (FO duration}_{2007}+..+\text{FO duration}_{2017})}{\#\text{FO over } 2007\rightarrow 2017}$$

3. The average amount of events (only used in the flexibility assessment)

This is the average amount of outage events that happen per year

$$\text{Average \#FO} = \text{Average (\# FO}_{2007}+...+\text{ \#FO}_{2017})$$

For the flexibility assessment, it is particularly important to cover unexpected outage events immediately after those occurred (fast flexibility) and during intra-day (slow-flexibility). After day-ahead, these fall under the scope of the adequacy analysis, in which the duration and the outage rate is particularly important (i.e. the time a unit is effectively in outage).

The resulting outage characteristics for each technology are summarised in Table 1. No maintenances are assumed during the winter period (November to March) in the framework of this study. For new-built capacity (GT, CCGT, diesel and CHP), 5% of forced outage rate was considered as considered by ENTSO-E for European adequacy studies.

2.5.4. Summary

Figure 2-29 summarises the data for Belgium per year that were described in the previous sections for thermal capacity, renewable sources, storage facilities, total consumption evolution and market response. These elements constitute the main input data provided to the model in order to perform the simulations.

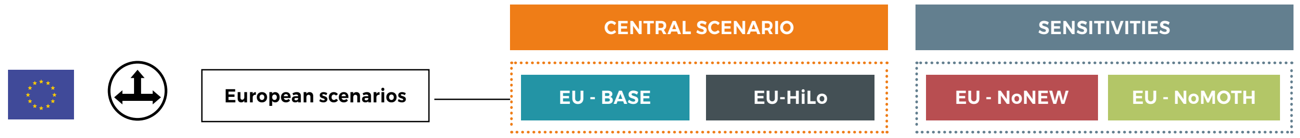
SUMMARY OF ASSUMPTIONS FOR BELGIUM [FIGURE 2-29]

Key assumptions for Belgium			2018	2020	2023	2025	2028	2030
Demand and electrification		Energy efficiency Economic growth	In line with WAM scenario from draft NECP submitted by Belgium to the EC					
		Amount of EV	20k	88k	306k	518k	919k	1310k
		HP (elec/hybrid) penetration	1.3k	5.5k	25k	68k	170k	249k
		Total Demand (incl. electrification) [TWh]	85.5	86.2	86.4	86.9	87.8	88.8
Market response		Shedding* [GW]	1.2	1.4	1.5	1.6	2.2	2.6
		Shifting [GWh/day]	≈0	≈0	0.3	0.5	1.1	1.5
Storage		in pumped storage [GW]	1.3	1.3	1.3	1.4	1.4	1.4
		in stationary batteries and EV [GW]	≈0	0.2	0.6	1	1.4	1.6
RES	[GW]		3.9	5.1	6.9	8.2	9.9	11
			2.3	2.8	3.3	3.6	4.1	4.5
			1.1	2.3	2.3	2.3	4	4
		Hydro RoR	0.12	0.12	0.13	0.14	0.14	0.15
		Biomass	0.8	0.8	0.7	0.5	0.5	0.5
Existing thermal	[GW]	CHP + waste	2.3	2.4				
		Nuclear	5.9	5.9	3.9	0		
		Existing CCGT/OCGT	4.4	4.0	Economic viability check (all existing units are considered unless their closure has been announced)			
		Existing CCGT-CHP**	0.5	0.5				
		Turbojets	0.1	0.1				
		New capacity (DSM, Diesels, CCGT, OCGT, Storage,...)			Possibility to invest in any new capacity (if economically viable)			

* including ancillary services volume

** Zandvliet and Inesco are categorised in CCGT-CHP to reflect their ability to operate in CHP mode

2.6. Assumptions for other European countries



2 scenarios complemented with 2 sensitivities are considered in order to capture uncertainties abroad which lead to major impact on the adequacy results for Belgium.

The **21 other European countries** considered in this study are **modelled with the same granularity as Belgium** (generation units, storage facilities, renewables, consumption, market response,...).

An overview of the different scenarios/sensitivities for the European assumptions is given in Figure 2-30. All scenarios/sensitivities have as a starting point the **latest ENTSO-E dataset collected among TSOs**, which is supposed to be in **line with the respective draft NECP plans** submitted to the EC at the end of 2018. As this study is performed while the dataset is being updated by every TSO, it is impossible to use exactly the same data that will be used for the MAF2019 (to be published later this year).

This dataset assumes several new capacities, as well as additional closures. While the nuclear and coal installed capacities are mainly driven by national policies, the gas-fired capacity considered in the scenarios is resulting from assumptions made by each TSO (those assumptions are usually consulted in each country when performing national adequacy studies). In order to reflect the fact that new gas-fired capacity assumed in the initial data could not be realised and that expected closures could be delayed (or units are re-integrated into the electricity market), two sensitivities are performed. Those are complemented with a scenario, including a long-term unavailability of units in France.

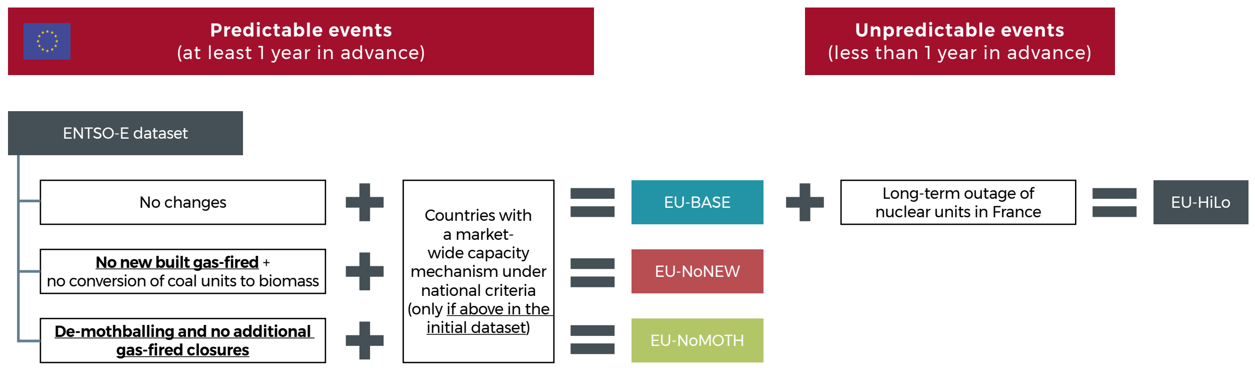
Two scenarios will always be used for all horizons and assessments:

- The **'EU-BASE'** scenario has no changes from the initial data. It only ensures that countries with a market-wide CRM meet their adequacy criteria;
- The **'EU-HiLo'** ('High Impact Low probability') scenario assumes that several nuclear units are unavailable in France (on top of 'normal' unavailability). Such a scenario is used in the framework of the strategic reserve volume evaluation and is compliant with the **EC State Aid approval** for this mechanism. This enables uncertainties abroad to be dealt with which are beyond Belgium's control.

Additionally, two sensitivities will be applied (as from 2025) to reflect uncertainty on the assumed gas-fired capacity evolution in the simulated perimeter:

- The **'EU-NoNEW'** sensitivity assumes no additional gas units in the market;
- The **'EU-NoMOTH'** sensitivity assumes no additional gas-fired unit is taken out of the market.

EUROPEAN SCENARIO FRAMEWORK [FIGURE 2-30]



2.6.1. Initial dataset

The dataset has the most up-to-date values and latest known policies for all of the 21 countries simulated.

The dataset used in this study has the most up-to-date data collected within ENTSO-E for all of the countries. The data are in line with the draft NECP and **include the latest coal and nuclear policies of all the countries**. Given that the data collection for the next MAF (to be published in the second half of 2019) was not finalised, it is impossible to guarantee that no changes will occur to the data for the MAF2019 study. The detailed capacities for the neighbouring countries (which are publicly available in the respective national studies) will be presented in the next sections.

The data provided within ENTSO-E are based on national adequacy studies or other studies (grid development plans,...) which are following national consultation processes and are adapted following remarks from different stakeholders.

Several key assumptions and policies have been introduced place since the most recent Elia adequacy assessments and European/regional adequacy assessments. The most significant are (non exhaustive list):

- **the 'Clean Energy Package' min 70% rule** for cross border capacity calculation (which will be explained and detailed in Section 2.7.2);
- **additional coal phase-out announcements or ambition for strong reduction** in coal/lignite installed capacities in the next decade. This concerns most Western European countries. Considered installed capacities in this study are much lower than in previous ones;
- **the French nuclear phase-out revision**;
- **the increased European targets for RES** and associated draft NECPs submitted to the EC which lead to an increase of the assumed RES in the electricity system.

2.6.2. Key indicators for the EU-BASE scenario

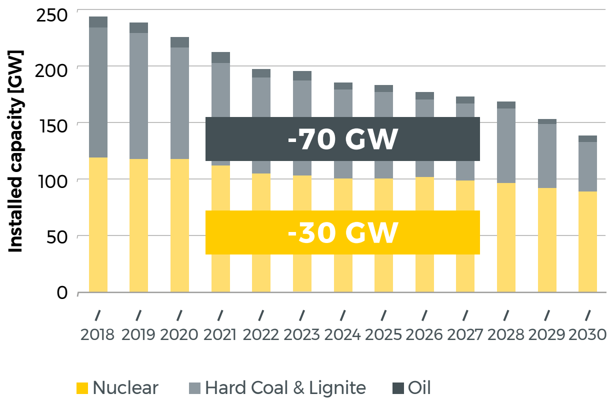
More than 100 GW of coal, lignite and nuclear capacity is planned to be phased out in the considered perimeter in the next decade.

Current nuclear and coal policies of the 21 simulated countries lead to a strong reduction of the thermal capacity in the next decade. By 2030, it results in a **reduction of 100 GW of nuclear and coal capacity, of which 60 GW is in Belgium's neighbouring countries** (DE,NL,FR and GB).

Additional gas-fired capacity is planned to be built. This includes around 11 GW in Germany and 6 GW in Great Britain, while around 9 GW is planned to be decommissioned.

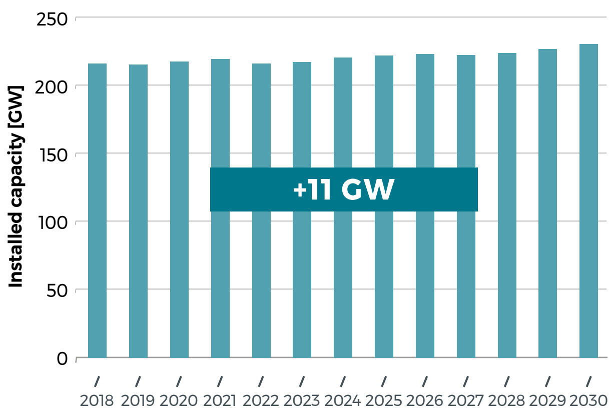
Installed capacity of offshore wind is expected to triple compared to the current one. A lower growth is expected for onshore wind. PV capacity is expected to triple from current values.

FUTURE EVOLUTION OF INSTALLED COAL/LIGNITE AND NUCLEAR CAPACITY IN EUROPE [FIGURE 2-31]



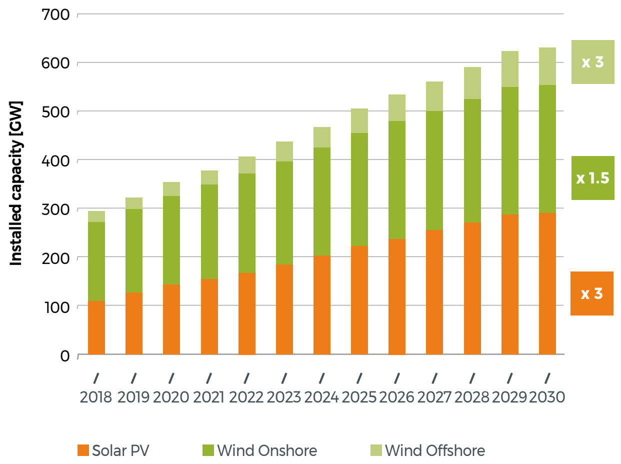
There are 20 GW of gas-fired units expected to be built and around 9 GW to be decommissioned.

FUTURE EVOLUTION OF GAS-FIRED CAPACITY IN EUROPE [FIGURE 2-32]



Renewable capacities are planned to at least double in the coming decade.

FUTURE EVOLUTION OF RES CAPACITY IN EUROPE [FIGURE 2-33]



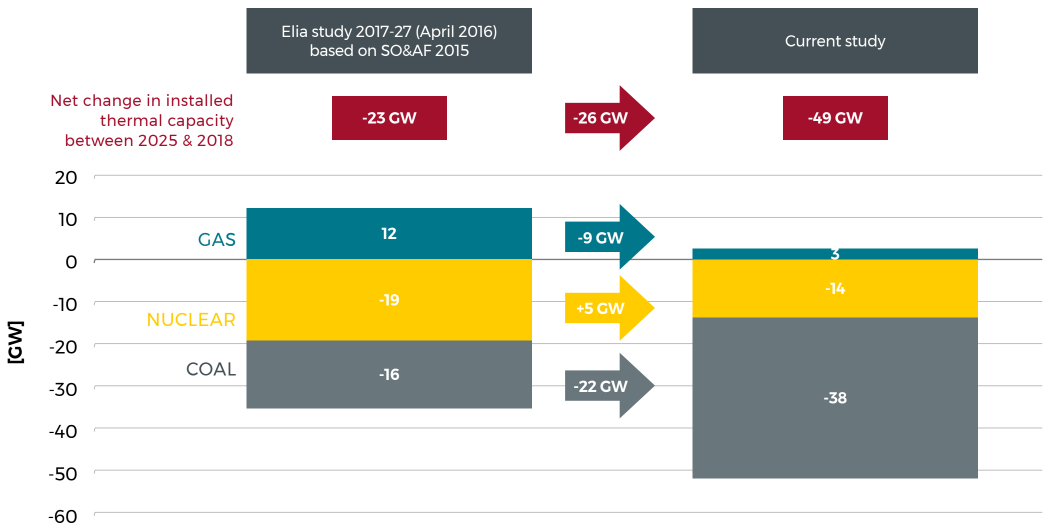
There is 26 GW less installed thermal capacity compared to the previous 'adequacy and flexibility study' published in April 2016.

In order to capture the differences with previous studies, Figure 2-34 illustrates the net difference in thermal capacity (in the simulated perimeter) between the previous '10-year adequacy and flexibility study' and the current one. For the year 2025 this results in the following:

- Less installed gas capacity is now assumed (-9 GW);
- More nuclear capacity is now (+5 GW);
- Less coal and lignite capacity is now assumed (-22 GW).

This results in 26 GW lower installed thermal capacity. This is a major change since the previous study.

CHANGE IN THERMAL CAPACITY BETWEEN 2025 AND 2018 IN THE PREVIOUS '10-YEAR ADEQUACY AND FLEXIBILITY STUDY' (PUBLISHED IN APRIL 2016) VERSUS THE CURRENT ONE [FIGURE 2-34]



2.6.3. France

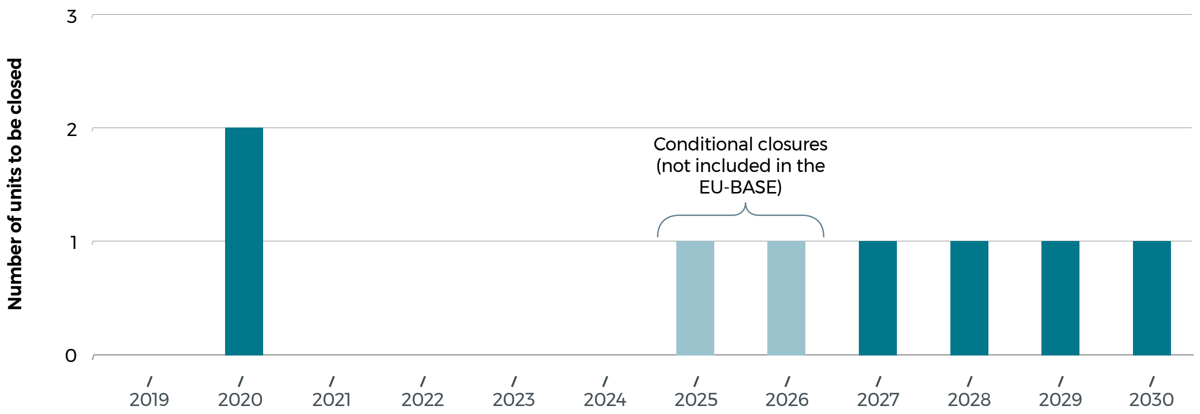
French assumptions are based on the **latest 'Bilan Prévisionnel 2018'** performed by RTE at the end of 2018 [RTE-1] for the next five years which was **complemented with the French 'Planification Pluriannuelle de l'Energie' (PPE)** also released end 2018 which, sets targets on nuclear and future RES capacities until 2028 [ECO-1].

NUCLEAR

The French generation fleet is mainly composed of nuclear capacity which accounts for around 63 GW. The French government has decided to maintain the current nuclear fleet until 2025 with the exception of Fessenheim nuclear units which are planned to be closed in the coming year.

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 'visite décennale - VD'. Given the large amount of units in France (58), there are several units passing such inspections every year. In June 2019, the reactor (Tricastin 1) will be the first one to start the fourth VD. There are always uncertainties around the length of the inspections given increased safety measures and depending on issues detected. The inspections could also lead to life-extension works that can last several months. Such uncertainties are tackled with the 'EU-HiLo' scenario (see Section 2.6.3). The calendar of nuclear closures (proposed by the PPE) is indicated in Figure 2-35. Note that in parallel, a new unit 'EPR' in Flamanville is being built, although there might be additional delays in its commissioning. In the installed capacity for this study, the new 'EPR' is assumed to come online when the two units from Fessenheim are being closed.

NUMBER OF NUCLEAR REACTORS TO BE CLOSED (ACCORDING TO THE PPE) [FIGURE 2-35]



OTHER CAPACITIES

The French government's ambition is to close the 2.9 GW coal units in France by 2022 which is also assumed in all the scenarios.

Concerning gas-fired units, it is assumed that this will stay stable over the coming decade and this includes the Landivisiau CCGT after 2020 for all scenarios and sensitivities.

The RES capacities are in line with the PPE, hence with the draft NECP submitted by France.

For the other and more detailed assumptions, the reader can refer to the most recent 'Bilan Prévisionnel' from the French TSO [RTE-3].

The summary table for France can be found in Figure 2-36.

INSTALLED CAPACITY EVOLUTION IN FRANCE [FIGURE 2-36]

[GW]	2018	2020	2023	2025	2028	2030
	63.1	63	63	63	61.2	59.3
	2.9	1.7	✗	✗	✗	✗
	6.8	6.8	7.2	7.2	7.2	7.2
onshore	14.6	19.1	24.6	28.4	34.1	36
offshore	0	0	2.4	2.9	2.9	4.9
	8.3	14.1	20.6	26.6	35.6	38.6

SENSITIVITIES

It is important to mention that in the scenarios 'EU-BASE', and sensitivities 'EU-NoNEW' and 'EU-NoMOTH', **the French adequacy criteria is forced to remain below 3 hours** irrespective of the assumptions taken abroad. This will be ensured by adding peaking capacity to the French market.

Given the big impact of French assumptions on Belgian adequacy, the 'EU-HiLo' scenario will consider additional nuclear units unavailable. This is further detailed in Section 2.6.8.

2.6.4. The Netherlands

The Dutch assumptions are based on the most recent '**MonitoringLeveringzekerheid**' **report** from the Dutch TSO (TenneT) published at the end of 2018 [TEN-1]. This adequacy study looks 15 years ahead including several sensitivities for the Dutch electricity system.

COAL

The Netherlands has already closed 3 GW of coal capacity in the past 5 years. In addition, the ambition to close all coal units by 2030 was taken into account in all the scenarios. The retained dates of closure are shown in Figure 2-37. These closures are complemented with the reconversion to biomass of all coal units closing after 2020 in the 'EU-BASE' and 'EU-NoMOTH'. Given uncertainty that such a conversion would be realised, the 'EU-NoNEW' sensitivity does not assume a reconversion to biomass.

OTHER CAPACITIES

The other capacities are based on the reference scenario of the TenneT adequacy study. A big increase in offshore wind and PV capacities is planned.

In terms of gas-fired units, a net decrease of around 3 GW is planned to happen by 2025 (from the 16 GW installed today). In total, 4 GW of units would be in the process of 'mothballing' from 2025. The sensitivity 'EU-NoMOTH' is constructed taking into account that the units in 'mothballing' are back in the market.

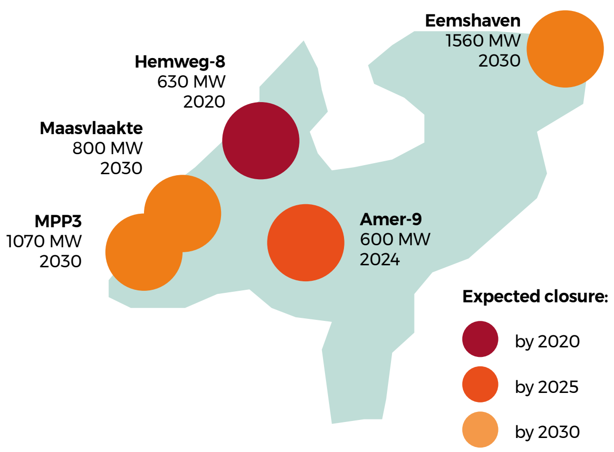
The 'ClausCentrale C' in Maasbracht (1.3 GW) is planned to come back to the market (it was currently mothballed) for 2020 and is therefore included in the simulated dataset for the Netherlands.

SENSITIVITIES

The **'EU-NoMOTH'** sensitivity will assume an additional 4 GW in the Netherlands.

The **'EU-NoNEW'** sensitivity will assume no conversion of coal units to biomass (-0.6 GW in 2025 and -4 GW in 2030).

INSTALLED COAL CAPACITY IN THE NETHERLANDS AND EXPECTED CLOSURE DATES [FIGURE 2-37]



INSTALLED CAPACITY EVOLUTION IN THE NETHERLANDS [FIGURE 2-38]

[GW]	2018	2020	2023	2025	2028	2030
	0.5	0.5	0.5	0.5	0.5	0.5
	4.7	4	4	3.4	3.4	X
Conversion of coal to biomass				0.6	0.6	4
	16.1	15.6	14.3	13.3	13.3	13.3
onshore	3.7	4.5	5.3	5.7	5.6	5.4
offshore	1	1.7	3.8	6.8	9.7	10.7
	3.9	6.1	9.5	11.9	14.5	15.3

2.6.5. Great Britain

The assumptions of generation capacity in Great Britain are based on the '**Steady Progression' scenario from the latest 'Future Energy Scenarios' (FES)** produced by National Grid and released in July 2018 [NGR-1].

COAL AND NUCLEAR

Coal units are assumed to have left the market by 2025. The nuclear capacity decreases until 2030 with a capacity three times lower (2.9 GW) than currently installed (9.2 GW). Regarding the evolution of nuclear capacity in GB, the following commissioning and decommissioning planning is foreseen for this study:

- Before 2023: 2.1 GW of existing nuclear capacity is planned to be decommissioned;
- By 2030: 3.2 GW of new nuclear capacity is foreseen with, in parallel, a gradual decommissioning of 7.4 GW of existing nuclear units.

In parallel, the offshore wind capacity is planned to increase in the coming years with a total capacity in 2030 (24.8 GW) three times higher than the current one (8.2 GW).

Finally, in order to cope with the coal phase-out and decreasing nuclear capacity until 2030, an increase of gas capacity is planned (which is partly compensated by the decommissioning of old gas units from 2020 to 2023).

Figure 2-39 summarises the assumptions for Great Britain per technology.

SENSITIVITIES

It is important to mention that in the scenarios 'EU-BASE', and in the sensitivities 'EU-NoNEW' and 'EU-NoMOTH', **the national adequacy criteria is forced in order to maintain it below 3 hours,** irrespective of the assumptions taken abroad. This will be ensured by adding peaking capacity to the market.

The **'EU-NoNEW'** assumes no new gas-fired units in Great Britain, although this is complemented with the addition of capacity to maintain the country below 3 hours.

The **'EU-NoMOTH'** assumes that the units that are planned to close, remain in the market.

INSTALLED CAPACITY EVOLUTION IN GREAT BRITAIN [FIGURE 2-39]

[GW]	2018	2020	2023	2025	2028	2030
	9.2	9.2	7.1	7.1	6	2.9
	10.2	8.3	2.8	X	X	X
	36	37.6	35	36.6	37.2	41.4
onshore	12.4	12.8	13	13.7	15	15.5
offshore	8.2	10	14	17.6	22.6	24.8
	12.9	13.7	14.3	14.7	15.6	16.4

2.6.6. Germany

The German assumptions are based on :

- The **"Systemanalysen der Übertragungsnetzbetreiber"** [BUN-1];
- The **Netzentwicklungsplan (NEP) scenarios (scenario B)** published at the beginning of 2019 [NEP-1]:.

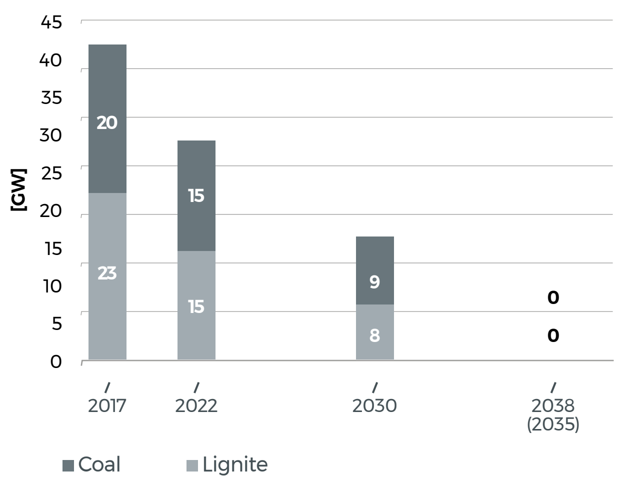
Those were complemented with the recommendation from the 'Growth, Structural Change and Employment' commission (also called **'Coal Commission') to close all coal and lignite capacity in the coming 20 years.**

COAL

There are currently **43 GW of coal capacity** installed in Germany. Following the recommendation of the 'Coal commission', 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). The values, as well as the split between lignite and coal, are given on Figure 2-40.

This highlights in one of the major differences with past adequacy studies. It results in more than 8 GW less capacity (as from 2021) than the one taken into account in studies prior to January 2019. This is also in line with the 'Low carbon' sensitivity that was simulated in the framework of the ENTSO-E MAF 2018 study where around 8 GW of coal capacity was removed in Germany.

RECOMMENDATION BY THE 'COAL COMMISSION' ON THE CAPACITY EVOLUTION OF COAL AND LIGNITE IN GERMANY [FIGURE 2-40]



OTHER CAPACITIES

The German nuclear phase-out is planned to be completed by 2022 (more than 9 GW expected to be closed).

The gas-fired capacity is assumed to increase (in the market) by 11 GW in the coming decade. In the absence of any anticipated market-wide CRM mechanism in Germany, there is however no guarantee that such capacity will come on line. The scenario 'EU-NoNEW' tackles this uncertainty by removing those assumed new built gas-fired capacities in Germany.

RES is expected to continue its growth by doubling the currently installed RES capacity (PV, wind) by 2030.

CAPACITY RESERVES

There are different capacity reserves in Germany for different purposes: the 'capacity reserves', the 'grid reserves' and the 'climate reserves'. As these capacities are 'out of the market' or contracted for other purposes, they cannot be relied upon by other countries for their security of supply.

- The **'capacity reserve'** was approved by the EC beginning of 2018 and would start to be procured in 2019. From winter 2020-21, there are 2 GW of capacity to be expected in this reserve. The value might be adjusted for upcoming winters. This 'out of market' capacity is to be used by German TSOs after the market clearing in order to safeguard German adequacy in the coming years;
- The **'grid reserves'** (or 'Netzreserves' in German) are contracted by the German TSOs to cope with congestion management and is not dispatched on the energy market. There are currently 6.8 GW in this reserve and the latest German study on the matter shows that for the winter 2022-23, the capacity to be contracted would increase to reach 10.6 GW. This capacity consists of units in the south of Germany which are being dispatched to solve congestions in the German grid. They also may participate in the 'capacity reserve' tender;
- The **'climate reserve'** or (or 'Sicherheitsbereitschaft' in German) is a temporary measure where a total of eight lignite power units with a total capacity of 2.7 GW are progressively taken out of the market for a financial compensation. Those units need to be able to be operational within 240 hours if requested by the TSOs. Those units are therefore temporarily shut down and will be finally shut down after four years in this mechanism. This mechanism is planned to be stopped in 2023.

SENSITIVITIES

The **'EU-NoNEW'** includes the removal of all new built gas-fired capacities (11 GW in 2030) in Germany to cover the uncertainty about their realisation.

INSTALLED CAPACITY EVOLUTION IN GERMANY [FIGURE 2-41]

[GW]		2018	2020	2023	2025	2028	2030
		9.5	8.1	✗	✗	✗	✗
		40.3	34.5	28	25.2	20.2	17
		25	26	31.3	33.9	35.5	36.1
	onshore	54.7	60.8	68.7	74.6	78.7	81.5
	offshore	7.3	7.9	9.5	13	15.2	17
		48.2	55.2	67.1	78.1	86	91.3

2.6.7. Adequacy of countries with a market-wide capacity mechanism is forced

The countries that have implemented a market-wide CRM are forced to have an adequate system in relation to their national reliability standard. The initial dataset might still show adequacy issues in those countries. If it is the case, additional capacity was added in order to comply with their adequacy criteria.

This is the case for:

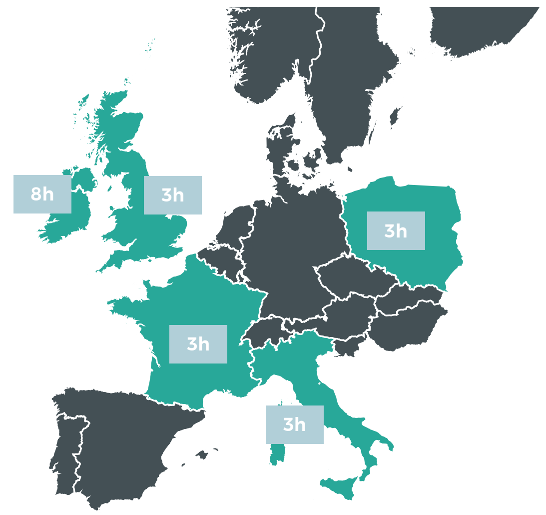
- Poland;
- Great Britain;
- France;
- Italy;
- Ireland and Northern Ireland.

Figure 2-42 highlights the countries on a map with the LOLE criteria to be respected in the simulations.

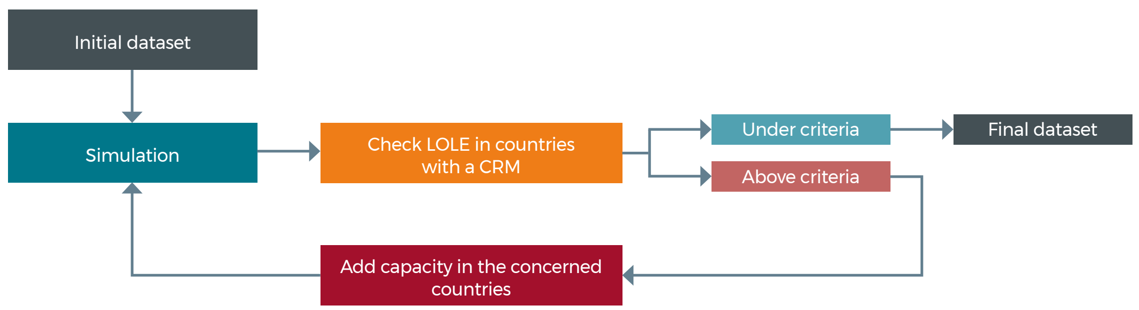
Note that some countries have strategic reserves in place to guarantee their adequacy. As these capacities are considered to operate out-of-market as last-resort solutions when a national scarcity situation would occur, these strategic reserves cannot be relied upon by other countries. The results of the market simulations are not impacted as these strategic reserves are supposed to be dispatched after the market has depleted all its in-the-market resources and de facto reaches the price cap. From a model perspective it does not impact the flows, nor the market prices.

Figure 2-43 highlights the iterative process to ensure that the above countries are within their national adequacy criteria. This process is followed for the 'EU-BASE', 'EU-NoMOTH' and 'EU-NoNEW'.

CRITERIA TO BE RESPECTED IN THE EU-BASE, EU-NOMOTH AND EU-NONEW SCENARIOS IN THE COUNTRIES WITH A MARKET-WIDE CRM [FIGURE 2-42]



PROCESS TO ENSURE THAT COUNTRIES WITH A CRM ARE ADEQUATE WITHIN THEIR CRITERIA [FIGURE 2-43]



2.6.8. High Impact Low probability ('EU-HiLo') scenario

The so-called 'High Impact Low Probability' (or 'HiLo') scenario is based on the scenario used to determine the strategic reserve volume for Belgium. This assumes that 4 nuclear units (3.6 GW) are unavailable in France, in addition to 'normal unavailability rates'.

DEFINITION OF THE EU-HILO SCENARIO [FIGURE 2-44]

The reasoning behind this scenario is justified by recent observations on the unavailability of the French nuclear fleet:

- RTE (the French TSO) has made an historical analysis of the forecasted and realised length of the 'VD' on nuclear units in France. It showed that on average, the duration of realised 'VD' is on average 2 months longer than forecasted (but with sometimes much more longer delays). More information can be found in [RTE-3];
- The last 3 years have experienced lower availability of the French nuclear fleet during the winter months (November to March) than observed in the past Figure 2-45 shows the average unavailability of the nuclear fleet over the past winters and the forecasts for future winters (based on REMIT data consulted in March 2019).

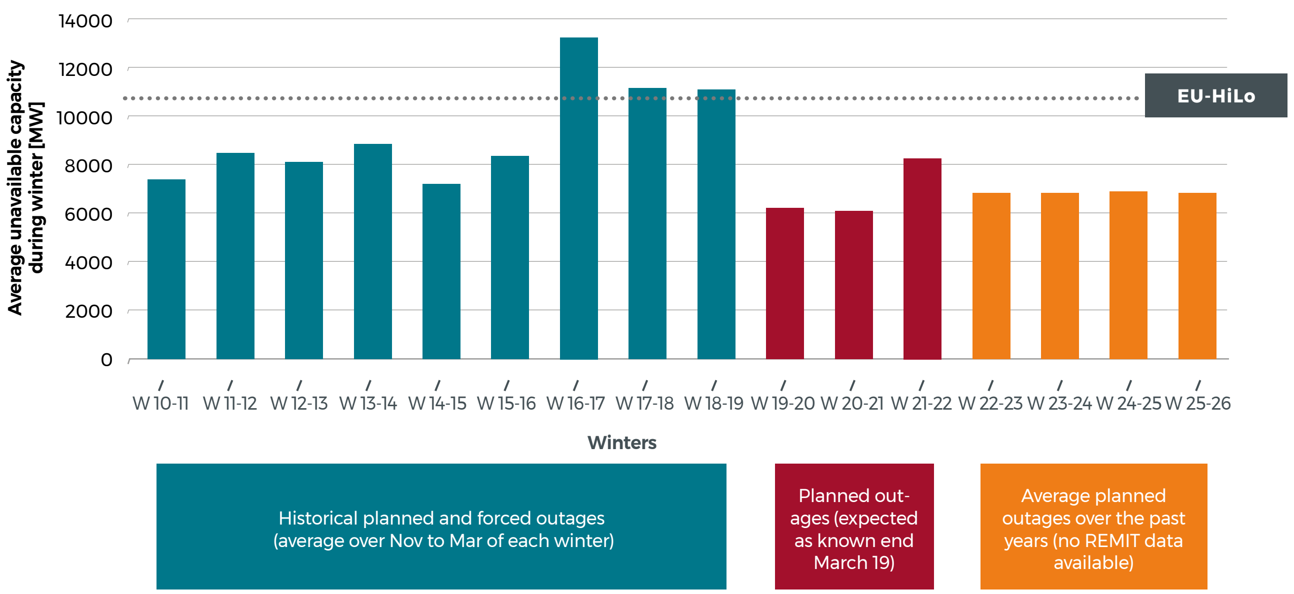
Future events might also affect this unavailability:

- Inspection delays following the '4th Decennial inspections' starting from this year could have a significant impact. Given that it will be the first time that units are going to extend their lifetime above 40 years in France and that there is no framework yet in place for those, new requirements could be put in place by the French nuclear safety authority (ASN). This could lead to longer inspections and 'common mode failures' in the case of issues found which affect more than one nuclear unit;
- All scenarios assume the new EPR in Flamanville to be online from 2021. If any further delays in the commissioning arise, this could lead to a 1.6 GW drop in nuclear capacity, compared to the 'EU-BASE' assumptions.

From Figure 2-45, one can clearly observe that the past three winters have experienced higher unavailability rates of the French nuclear fleet. This justifies the 'EU-HiLo' scenario by taking into account an additional unavailability of 4 units in the simulations.

In the 'EU-BASE' scenario, the planned outages, such as forecasted in March 2019 will be taken into account (when available). For the next years (where no REMIT data is available yet), the 'normal availability rates' for France are used.

AVERAGE NUCLEAR UNAVAILABILITY DURING WINTER MONTHS IN FRANCE [FIGURE 2-45]



2.6.9. Sensitivities

2.6.9.1. NO GAS-FIRED UNITS MOTHBALLING (EU-NOMOTH)

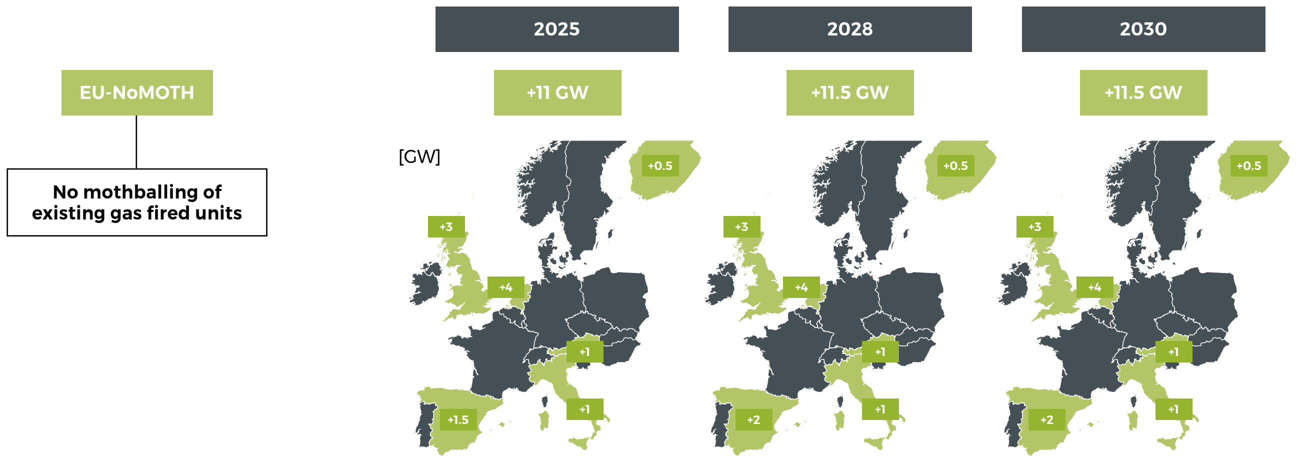
In the 'EU-BASE' scenario, the most up-to-date assumptions are considered in terms of the decommissioning of existing units. The 'EU-BASE' scenario assumes that certain gas-fired units will be closed in the future or a certain level are in the process of mothballing. In order to assess the impact of such closures (less driven by national policies), the sensitivity 'EU-NoMOTH' was constructed. Figure 2-46 gives the capacities that are added to the market in each country (compared to the 'EU-BASE' scenario).

2.6.9.2. NO NEW BUILT GAS-FIRED CAPACITY (EU-NONEW)

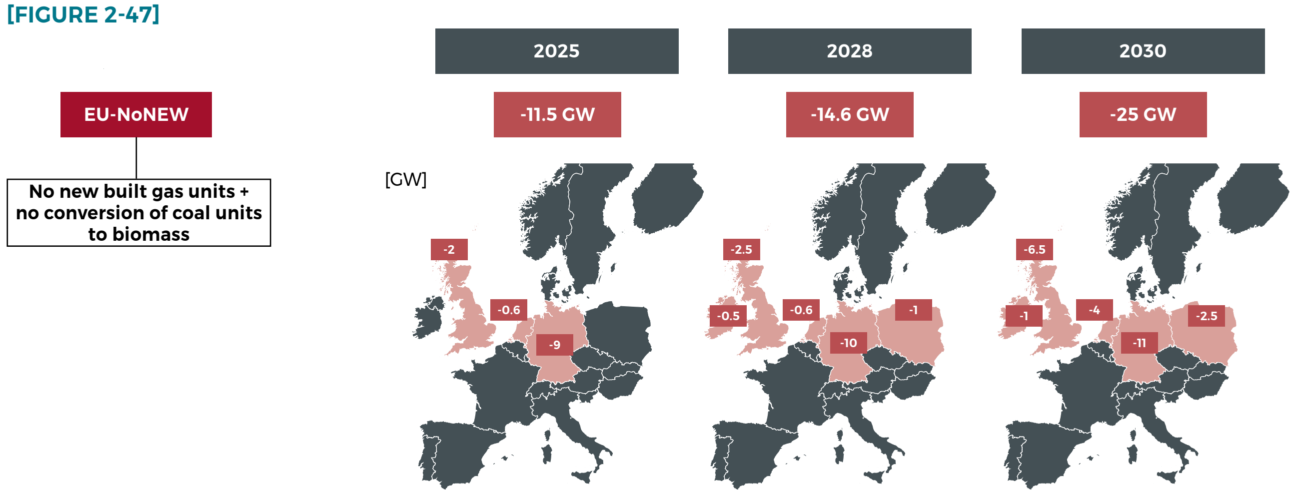
In the 'EU-BASE' scenario, a certain volume of new built gas-fired capacity (CCGT, OCGT or CHP) is assumed in some of the countries. In total this represents around 21 GW by 2030 in the simulated perimeter. Those additions are still uncertain however, as projects might not be viable without support. The sensitivity 'EU-NoNEW' aims to evaluate the needed capacity in Belgium if those plans do not materialise. In order to capture the uncertainty about the conversion of coal units to biomass in the Netherlands, the assumed units to be converted (around 4 GW by 2030) are also removed from the market in this sensitivity.

This sensitivity will mainly affect the installed capacity in Germany and the Netherlands as those are the only countries without a market-wide CRM that assume new built gas-fired units in the future or conversion to biomass. For the other countries, the national adequacy criteria is forced again after the removal of new capacities (see Section 2.6.7).

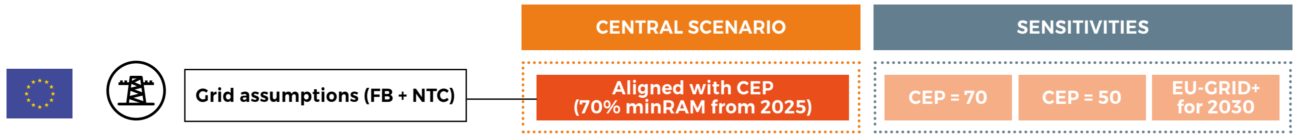
DEFINITION OF THE EU-NOMOTH SENSITIVITY (CHANGE IN CAPACITY COMPARED TO THE EU-BASE SCENARIO) [FIGURE 2-46]



DEFINITION OF THE EU-NONEW SENSITIVITY (CHANGE IN CAPACITY COMPARED TO THE EU-BASE SCENARIO) [FIGURE 2-47]



2.7. Assumptions regarding the grid and cross-border exchange capacities



Belgium is at the heart of the interconnected European grid. It is geographically neighboured by France, the Netherlands, Germany and Luxemburg. Furthermore, since the start of 2019 Belgium is electrically connected to the United Kingdom through a subsea HVDC cable. Depending on the situation of their respective grids and markets, each of the neighbouring countries can import or export large amounts of electricity. As Belgium is structurally dependent on imports to ensure its adequacy, a correct modelling of the cross-border exchange capacity is crucial.

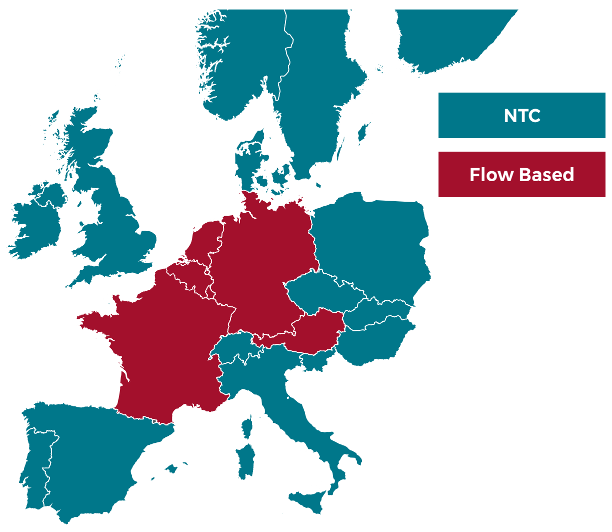
Furthermore, as Belgium is at the centre of the CWE zone, the country's import and export capabilities are currently defined by the flow-based methodology used at regional level for the day-ahead markets since 2015. Belgium's net position is therefore linked to the net position of the other countries 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.

In the market simulations performed for this study, the commercial exchange capacities are modelled in two different ways:

- **For exchanges** inside the **CWE region**, the **flow-based methodology** as described in Section 2.7.2 is applied;
- **For exchanges** between two countries **outside the CWE region** and between a country outside the CWE region and the CWE region, fixed bilateral exchange capacities (also called **NTC** – Net Transfer Capacities) as described in Section 2.7.1 are applied.

The hourly commercial electricity exchange between countries is optimised by the model, depending on the supply and demand curves in each country. The model therefore does not a priori assume a given level of imported energy at the critical moments for system adequacy. The actual volumes of imported energy will depend on the extent to which excess generation capacities are available for export in the other countries, on the available commercial exchange capacity and on the result of the market.

BIDDING ZONES CONSIDERED AND CAPACITY CALCULATION METHOD APPLIED [FIGURE 2-42]



BOX 7: CWE AND CORE CAPACITY CALCULATION REGIONS

At the moment, the day-ahead flow-based Capacity Calculation Region (CCR) (of which Belgium is part) is limited to the CWE countries: Belgium, the Netherlands, France, Germany, Austria and Luxemburg. In line with the the CACM (Capacity Allocation and Congestion Management) regulation (EU) 2015/1222) ACER issued its decision no 06/2016 on the determination of CCRs, introducing the CORE capacity calculation region. This CORE region includes the Czech Republic, Croatia, Hungary, Poland, Romania, Slovenia and Sovakia on top of the CWE countries.

The CORE day-ahead capacity calculation is planned to enter into force on 1st December 2020, which falls inside of the studied horizon of this study. All of Belgium's neighbouring countries are in the CWE CCR which is operational today. Although there might be an impact of the transition to the CORE CCR, the commercial exchange capacity available to Belgium to ensure its generation adequacy is sufficiently accurately modelled by only considering flow-based modelling for the CWE countries

2.7.1. NTC for non-CWE countries

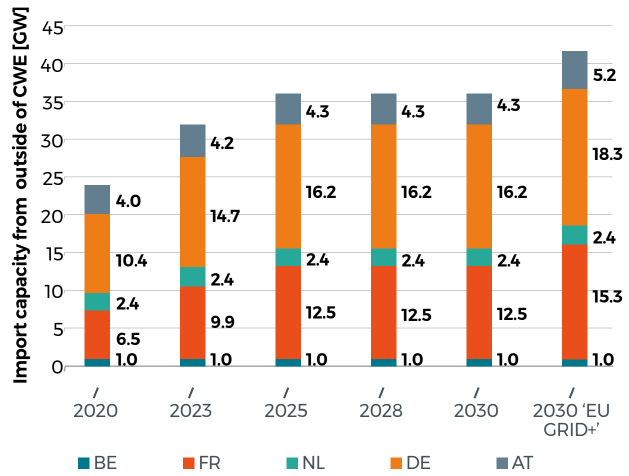
All scenarios take the latest commercial exchange capacities known and used in the framework of the ENTSO-E MAF.

A sensitivity is performed considering higher values for 2030 (GRID+) to assess how further grid development abroad impacts Belgian adequacy.

The commercial exchange capacities for non-CWE countries are modelled with 'Net Transfer Capacities' (NTC), corresponding to fixed maximum commercial exchange capacities for exchanges between two bidding zones. The values are taken from the most recent dataset available at ENTSO-E and from bilateral and multilateral contacts with TSOs, and are in line with those used for studies conducted within ENTSO-E (latest MAF study). Planned and new interconnection projects for all borders are taken into account in the values used.

In this study, a single NTC reference value is considered for a given interconnection in a certain direction for a simulated target year. 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. Figure 2-49 shows the evolution of the import capacity from outside of the CWE region per country for each analysed time horizon. The figure also shows the import capacities from outside of the CWE region for the 2030 'EU GRID+' sensitivity (which considers an increase in the NTC capacity (outside the CWE region) based on the TYNDP 2018 reference grid.

IMPORT CAPACITY FROM OUTSIDE OF CWE PER COUNTRY [FIGURE 2-49]



2.7.2. Flow-based for CWE countries

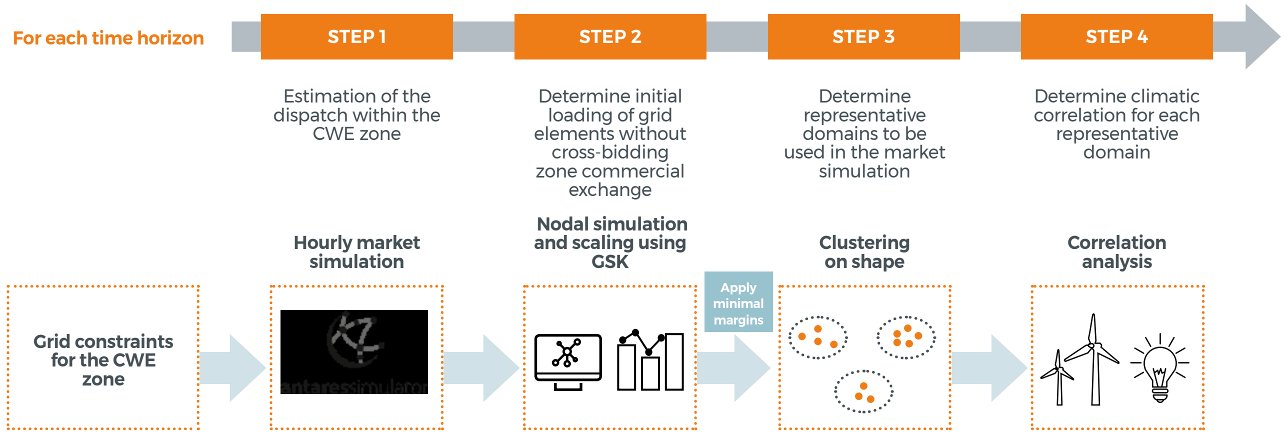
The commercial exchanges between the CWE countries are in operations limited by so-called flow-based domains. For short-term studies (e.g. the volume determination of strategic reserves) the used flow-based domains are generally based on historical data. However, for mid- and long-term studies the historical approach is no longer appropriate due to several expected changes in future years that need to be incorporated in order to obtain representative exchange capacities (including new rules, grid reinforcements, evolved generation mixes, etc.).

Therefore, for this study, a methodology has been developed to create flow-based domains for a given target year on the mid- and long-term. This section gives a high-level overview of the developed methodology and its main results.

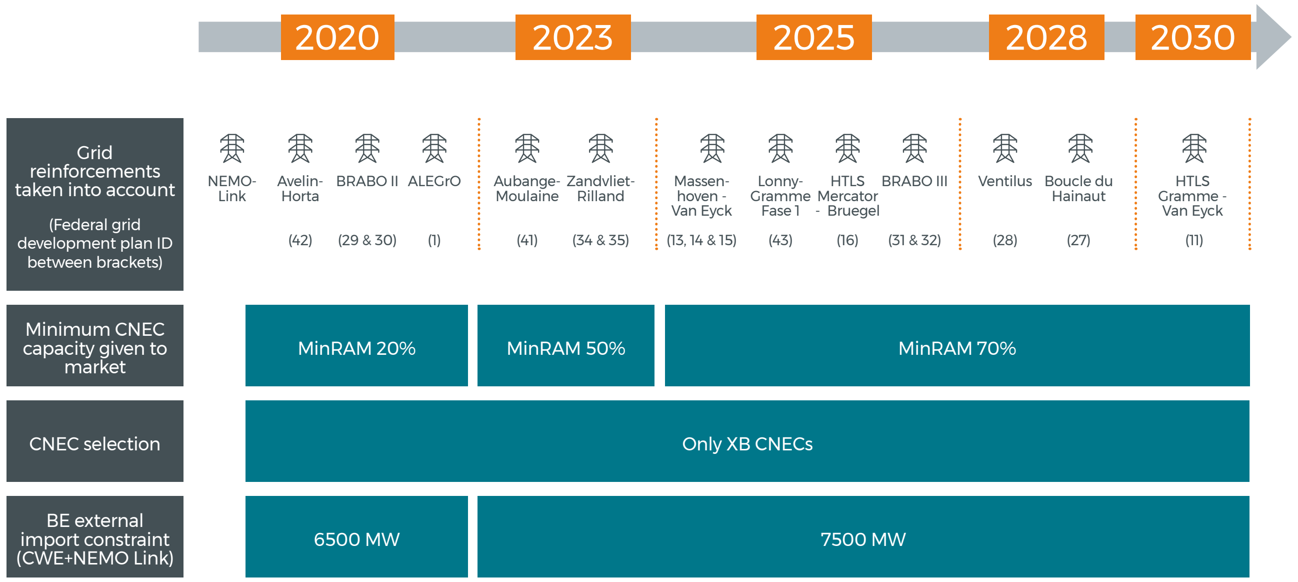
Figure 2-50 gives an overview of the different steps in the process of the determination of the flow-based domains.

For further details, please refer to Appendix B

PROCESS FOR THE DEVELOPMENT OF THE FLOW-BASED DOMAINS [FIGURE 2-50]



CAPACITY CALCULATION ASSUMPTIONS FOR THE CWE ZONE (FLOW-BASED) [FIGURE 2-51]



STEP 0

The flow-based domains are constructed based on grid constraints, representing the limits of the network elements. For this study, a European grid model developed in the context of the ENTSO-E Ten Year Network Development Plan (TYNDP) was used. For the Belgian grid and the Belgian interconnections, the model was updated and detailed for each time horizon. For the rest of the European grid, the TYNDP 'reference grid' was used which is based on the expected grid for 2027. This assumption will probably result in an overestimation of the commercial exchange capacity for studied horizons 2020, 2023 and 2025 as foreign grid reinforcements might already be taken into account which are not planned to be realised by those horizons.

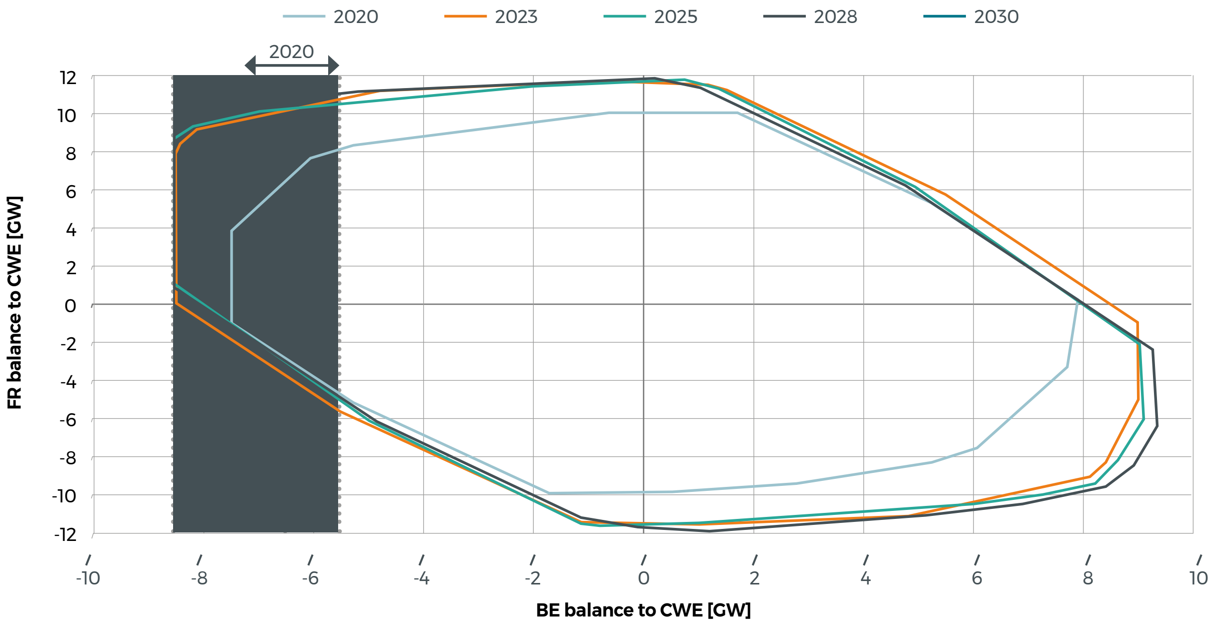
The grid models are transformed into combinations of linearised constraints composing a flow-based domain using a GSK pro rata to the dispatchable installed capacity in each bidding zone. The flow-based domains constrain the 6 variables of the CWE zone: the CWE balance of the 5 bidding zones (BE-NL-FR-DE/LU-AT), and the setpoint of the ALEGrO HVDC interconnector. For this study, only cross-border elements are retained to potentially constrain the commercial exchanges. Apart from the previous remark on foreign grid reinforcements, this assumption is a second reason why the created domains might depict a rather optimistic view of the future. All grid elements are considered to be available for the whole year. As grid maintenance is usually scheduled outside of the winter period when scarcity issues arise, this is a good assumption for adequacy studies.

Exchanges with countries outside of the CWE zone are modelled using standard hybrid coupling. As a domain in more than two dimensions cannot be visualised, in this report the projection (convex hull) of this domain onto the Belgian-French plane is depicted. As Belgium and France are usually linked in terms of scarcity events and both are relying on imports to guarantee adequacy, such representation provides a good view of the domain impact on Belgium's import capabilities.

Figure 2-52 shows the domains without the initial loading of the grid elements for each studied time horizon. These domains therefore reflect a situation where the full (N-1 secure) physical capacity on each cross-border grid element would be available for commercial exchanges. Apart from constraints linked to individual grid elements, an external constraint reflecting the restriction on the simultaneous importing capacity for Belgium is also considered. Such a restriction is required to ensure the stability of the Belgian system and a correct voltage control in combination with high importing levels. For 2020 this limit is set at 6500 MW, though this limit increases to 7500 MW for further time horizons thanks to additional investments in voltage control. More information can be found in the Elia Federal Development Plan 2020-2030, Section 4.1.9 [ELI-14] . Note that this limit was consistently set to 6500 MW for previously conducted adequacy studies. It is important to note that this restriction is applied on the global balance of Belgium, including both the CWE balance and the flow on the NEMO Link HVDC interconnector. The restriction is therefore depicted on the CWE domain plots as a 'feasibility' area.

/ SCENARIOS AND ASSUMPTIONS

FLOW-BASED DOMAINS WITHOUT INITIAL LOADING OF GRID ELEMENTS [FIGURE 2-52]



Restriction on the Belgian simultaneous import capacity (including Nemo Link):
■ 7500 MW as of 2023
■ 6500 MW for 2020

STEP 1

Using these domains, a first market simulation in Antares is performed, taking into account each grid element's entire seasonal rated capacity. In this simulation, PSTs are used up to two-thirds of their tap range in order to optimise the market's welfare. This market simulation gives an estimation of the dispatch within CWE, with the goal of determining realistic initial loadings of all grid elements in the market coupling.

STEP 2

In a next step, combining geographical information on the location of load and generation within CWE with the hourly market dispatch from STEP 1, the loadings of grid elements associated with the hourly commercial exchanges resulting from the market simulation in STEP 1 can be determined for each hour. However, for the market domain initial loadings of grid elements without any commercial exchange are required. Using the bidding-zone GSK, the net position of each of the bidding zones is scaled to zero. Hereby, commercial exchanges between bidding zones are cancelled, and the remaining flow on grid elements equals the initial loadings (loop flows and potentially some internal flows). The process used to scale bidding zones' net positions to zero is the same as the one used in flow-based operations today.

Such initial loadings could potentially pre-use a significant portion of the physical capacity of grid elements, and thereby restrict market operations. As from 1 January 2020, the 'Clean Energy Package' will be applicable. In this regulation, specific requirements related to the availability of transmission capacity for market exchanges are introduced. To model the application of those rules for future time horizons, minimal margins are applied to each grid element determining the created flow-based domains (for Belgian interconnectors as well as foreign interconnectors). As depicted in Figure 2-51, the currently applied 20% minimum margin is enforced on the 2020 horizon in CWE. This minimal margin is increased to 50% for 2023 and to the CEP target of 70% for 2025.

BOX 4: MINIMAL MARGINS (CEP), FEASIBILITY OF MARKET OUTCOME, AND REDISPATCHING

In order not to let trades within one bidding zone limit cross border trade, minimal margins are applied on all network elements. At the moment, in the CWE FB market coupling a minimal margin of 20% is applied to constraining network elements during the flow-based capacity calculation. As specified in the 'Clean Energy Package' regulation (see some extracts of relevant parts of the regulation below), these margins are supposed to reach 70% by 2020, however derogations and action plans mean it is only possible to make a stepwise increase of the currently applied margins to 70% in 2025 at the latest. In the present study, a gradual increase of the applied minimum margins was considered (see Figure 2.50) : 20% in 2020, 50% in 2023 and 70% as of 2025.

The minimal margins are applied for the commercial exchange capacity calculation, and therefore could increase commercial exchange capacities beyond what is physically feasible. Therefore, the resulting net positions of the bidding zones might not reflect a secure grid situation, and significant redispatching could be required. For the present study the physical feasibility of the market outcome (including the availability of the resulting dispatch requirements that would be needed to secure this feasibility) is taken as a given.

Article 16 General principles of capacity allocation and congestion management

[...]

8. *Transmission system operators shall not limit the volume of interconnection capacity to be made available to market participants as a means of solving congestion inside their own bidding zone or as a means of managing flows resulting from transactions internal to bidding zones. Without prejudice to the application of the derogations under paragraphs 3 and 9 of this Article and to the application of Article 15(2), this paragraph shall be considered to be complied with where the following minimum levels of available capacity for cross-zonal trade are reached:*

(a) for borders using a coordinated net transmission capacity approach, the minimum capacity shall be 70% of the transmission capacity respecting operational security limits after deduction of contingencies, as determined in accordance with the capacity allocation and congestion management guideline adopted on the basis of Article 18(5) of the Regulation (EC) No714/2009;

(b) for borders using a flow-based approach, the minimum capacity shall be a margin set in the capacity calculation process as available for flows induced by cross-zonal exchange. The margin shall be 70% of the capacity respecting operational security limits of internal and cross-zonal critical network elements, taking into account contingencies, as determined in accordance with the capacity allocation and congestion management guideline adopted on the basis of Article 18(5) of the Regulation (EC) No 714/2009.

The total amount of 30% can be used for the reliability margins, loop flows and internal flows on each critical network element.

STEP 3

As the market simulation performed in STEP 1 creates an estimation of the dispatch and corresponding initial loadings within CWE for each hour of the simulated year, this would result in 8760 different flow-based domains. For the present study, it was chosen to limit the amount of flow-based domains to three for each time horizon in order to obtain feasible computation times and to increase transparency on the model. First, a clustering algorithm based on the geometrical shape of the domains is applied in order to create three clusters. Next, a representative domain is selected for each clustered set of domains leading to three representative domains to be used in the model. Figure 2-53 shows the resulting three flow-based domains for the 2025 horizon.

FLOW-BASED DOMAINS FOR 2025 [FIGURE 2.53]

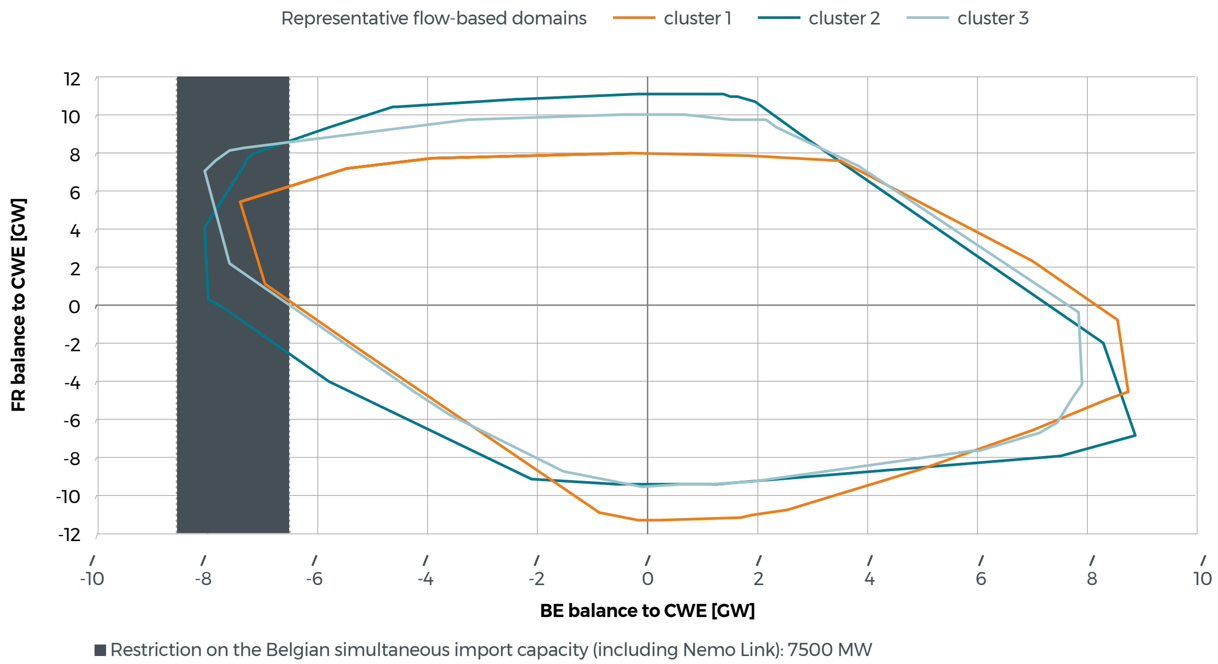
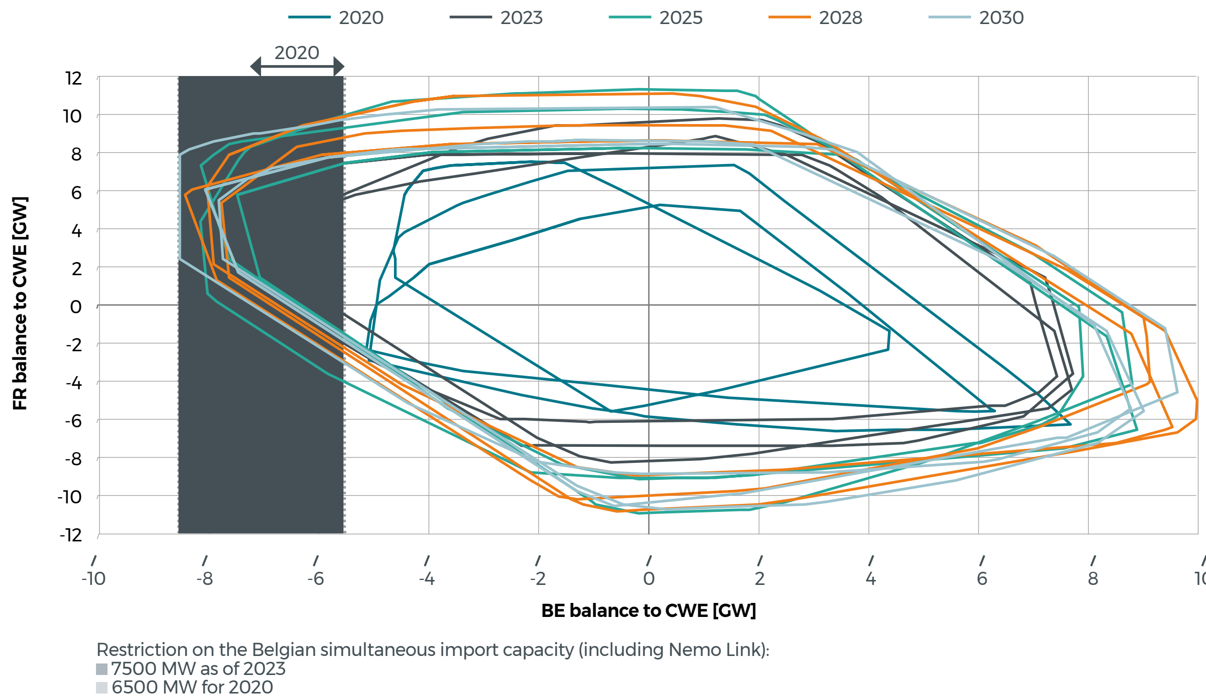


Figure 2-54 shows the resulting three representative domains for each time horizon. The size of the domains increases with time, partly due to the grid reinforcements taken into account. However, the minimal margins which are applied onto each grid element also have a large effect. Please refer to Figure 2-51 for the minimal margins used for each time horizon.

FLOW-BASED DOMAINS FOR THE DIFFERENT TIME HORIZONS [FIGURE 2-54]



STEP 4

In a final step, for each time horizon, a correlation analysis between the three domain clusters and several input parameters was applied in order to link a given market situation to the flow-based domain to be applied. This analysis resulted in the selection of German wind infeed and French consumption as the most relevant parameters in determining the selection of the domain. Therefore, in the final simulations the hourly choice of the applied domain is based on this correlation with the said external parameters. As an example, Figure 2-55 gives the probability for each representative domain to occur depending on the climatic conditions for 2025. For more information on this process, please refer to Appendix B.

PROBABILITY FOR EACH REPRESENTATIVE DOMAIN TO OCCUR DEPENDING ON CLIMATIC CONDITION FOR 2025 (FIGURE 2-55)

		GERMAN WIND		
		HIGH	MEDIUM	LOW
French load	High	(0.12, 0.69, 0.19)	(0.45, 0.27, 0.27)	(0.58, 0.18, 0.24)
	Medium	(0.24, 0.53, 0.24)	(0.48, 0.24, 0.27)	(0.67, 0.08, 0.24)
	Low	(0.32, 0.25, 0.43)	(0.43, 0.15, 0.43)	(0.47, 0.11, 0.42)

(x,y,z)
x = Probability of representative domain 1
y = Probability of representative domain 2
z = Probability of representative domain 3

2.7.3. Handling simultaneous scarcity situations

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

If a single country has a structural shortage (day-ahead price reaches price cap in that country) the adequacy patch ensures that the maximum feasible import capacity will be allocated to that country without creating curtailed energy in other exporting countries.

When two or more countries simultaneously have a structural shortage, imports will be allocated to those countries in proportion to their respective needs (price-taking orders).

For the purposes of this adequacy study, a model of the adequacy patch is applied on the results from ANTARES in post-processing.

More information about handling simultaneous scarcity events can be found in Appendix C

2.7.4. Sensitivities on the market exchange capacities (CEP=50% and CEP=70%)

While CEP requirements target a minimal margin level of 70% by 2025 at the latest, different reasons (in Belgium or in other European Member States) might exist that could lead to domains smaller than those determined as explained in previous sections of this report. Some of those reasons could be:

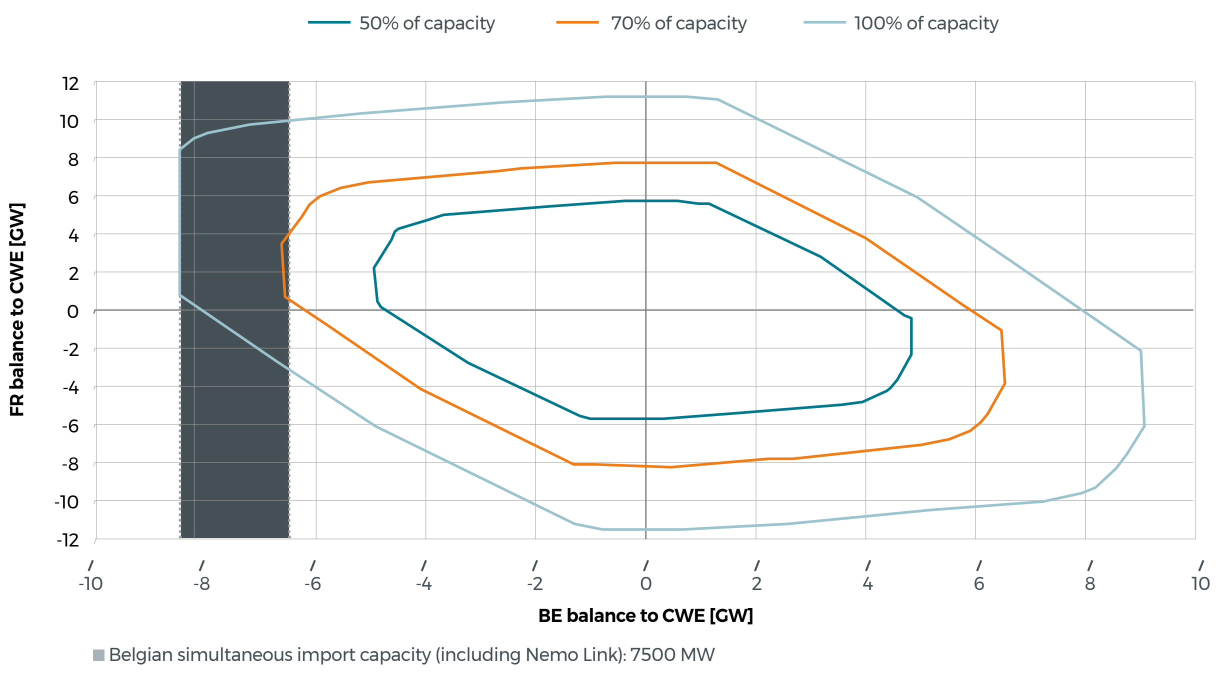
- The potential use of derogations for specific reasons and if justified, this could lead to the (temporary) application of a lower minimal margin level;
- CEP requirements target a minimum margin of 70%. However, applying the methodology as described above generally leads to domains with a margin given to the market above 70% for a number of grid elements. This could be overly optimistic if by ensuring such a higher margin this would lead to potential additional redispatch costs and is therefore not justified;
- Current requirements do not exclude the existence of grid elements internal to a Bidding Zone constraining the market. As it is currently computationally not possible to include such internal grid elements in the model, reducing the minimal margin level on cross-border elements is considered a proxy for the inclusion of internal constraints into the market coupling.

To capture the impact of those uncertainties, two sensitivities are assessed where the exchange capacities given for cross-border exchanges are reduced. The first scenario assumes that a margin of exactly 70% of the physical capacity (including N-1) is ensured for the market. Such a scenario remains in line with the CEP requirements. A second scenario assumes that a margin of exactly 50% is ensured for the market. Such a scenario might not be in line with the general CEP requirements (and therefore require one or more derogations), but could still remain in line with CEP in case internal constraints are considered.

SENSITIVITIES ON THE FLOW BASED CAPACITY CALCULATION AFTER 2025 [FIGURE 2-56]

Description	Parameters	Scenarios/sensitivities
'EU-BASE' scenario: Full CEP implementation in CWE from 2025	MinRAM 70% Only XB lines	EU-BASE, EU-NoNEW, EU-NoMOTH
'EU-CEP=70': Delay or derogations for CEP rules	Only MinRAM 70%, not more Only XB lines	EU-CEP=70
'EU-CEP=50': Delay or derogations for CEP rules	Only MinRAM 50%, not more Only XB lines	EU-CEP=50

FLOW-BASED DOMAINS FOR 2025 WITH FIXED RAM [FIGURE 2-57]



2.8. Assumptions concerning flexibility

2.8.1. Prediction data

Prediction data of total load and renewable generation are based on dedicated forecasting tools for which the real-time results are published on Elia's website. Although the flexibility needs of the system are driven by the predictions and operational decisions of market players, this forecast data is assumed to be representative for the tools used by market players.

The **estimated or observed total load, renewable and distributed generation** is based on measurements, monitoring and upscaling. The forecasted (day-ahead, intra-day and last forecast) values are obtained from external service providers. A correction of the forecast error is done when Elia activates a decremental bid on these units. In order to take a representative data set into account, two subsequent full years (2017 and 2018) are selected.

For future **forecast improvements**, an average cumulative improvement factor of 1% per year is taken into consideration between 2017-18 and 2030. This means that the forecast error is corrected to 99.00% of its value towards 2019, 98.01% for 2020 by means of a factor $(1 - 0.01)^y$ in which y is the year for which the forecast errors are calculated. This will result in a reduction of the original forecast errors of 2017-18 down to 88.6% of their original values in 2030.

These forecast accuracy improvements are mainly attributed to increasing geographical dispersion, smoothening out prediction errors. No significant improvements are expected for the weather forecast models (except for better predicting extreme weather conditions). Furthermore, the integration of new technologies such as electric vehicles, heat pumps and other decentral capacity is expected to result in new patterns which increase the complexity of forecasting algorithms.

2.8.2. Outage characteristics

The **forced outage probability** of power plants is based on the historical records of power plant outages between 2007 and 2017. The parameters are aggregated per technology type as can be seen in Table 1 in Section 2.5.3. It is determined based on the historic amount of forced outages per year and used to determine the forced outage risks accounted in the flexibility needs analyses. Note that this parameter has to be distinguished from the average forced outage rate and the average forced outage duration, used in the adequacy analyses (see Section 2.5.3).

The forced outage probability of NEMO-Link is assumed to be two per year in each direction. While awaiting return on experience with the operation of NEMO-Link, this figure is justified on the basis of other HVDC-link experiences in Europe (e.g. BritNed), although such experiences can never be translated one to one directly because of differences in technologies. The outages in grid elements in the meshed grid are assumed to be covered in the capacity calcultation method (N-1 criterion).

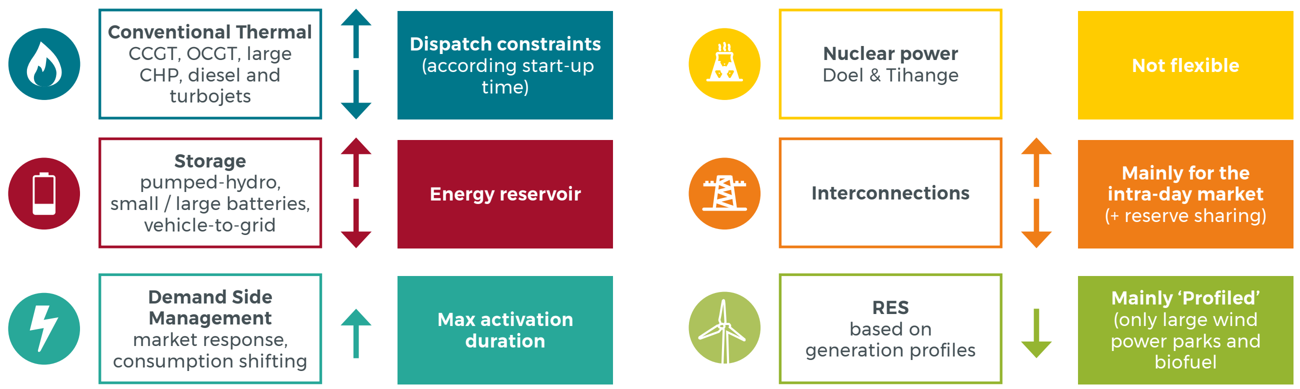
No forced outages are explicitly accounted for renewable generation, decentral 'must run' generation (e.g. combined heat-and power) and market response. Market response volumes are typically based on aggregation and it is assumed that the forced outage probability is taken into account when determining the available capacity. The forced outages of renewable generation and decentral 'must run' generation units is implicitly taken into account in the prediction and estimated generation profiles.

2.8.3. Technology characteristics

The technical characteristics concerning flexibility are based on a literature review, Elia's expertise and comments received from stakeholders in the framework of the public consultation on input data. A detailed overview of all the technical characteristics of each technology can be found in an Excel file published together with this report.

This overview is summarized in Figure 2-58.

SUMMARY OF TECHNOLOGICAL CAPABILITIES CONCERNING FLEXIBILITY [FIGURE 2-58]



Firstly, the ability to provide flexibility is determined by the **operational characteristics** (minimum up/down time, hot/warm/cold start-up time, transition time from hot to warm / warm to cold, minimum stable power, rated power and the ramp rate). In general, these constraints are particularly relevant for thermal power plants.

Secondly, where relevant, an **energy limit** is taken into account to represent the maximum duration a technology can be used to provide flexibility at its rated power, Although this is generally only relevant for non-thermal units (storage, demand-side response), it may also apply to combined heat and power.

Thirdly, the **maximum remaining flexibility is accounted** which is used to provide in the different types of flexibility needs which are studied in this report such as ramping (able to react on a minutely basis), fast (able to be activated in 15 minutes) and slow flexibility (able to be activated in 5 hours). The different types of flexibility are further elaborated in Section 3.4.2. A distinction is made between up- and downward flexibility. In general, this constraint is determined by the scheduled output for day-ahead market simulations, and the rated power and minimum stable power:

- **Nuclear power units** are not considered flexible. Although some of the nuclear generation units (in France and some limited events in Belgium) have proven to be able to provide some downward regulation (to some extent and under specific conditions), these are still considered as base load generation today and treated as non-flexible in this study.
- **Conventional thermal units** are considered flexible and can deliver each type of flexibility when dispatched. The only constraint results from the difference between day-ahead schedule and their minimum stable power (downward flexibility) and the difference between the day-ahead schedule and the rated power (upward flexibility). However, most units require a start-up time and cannot deliver fast or ramping flexibility, i.e. old, recent and new CCGT, when not already dispatched. Other types such as new and existing OCGT, turbojets and diesel generators can deliver fast upward flexibility from stand-still by means of a fast start-up time. The ramping flexibility is only provided by units which are effectively dispatched, and limited by the maximum ramp rate of the unit.
- **CHP units** are considered as two different types, i.e. 'individually modelled' and 'profiled'. The latter is considered must run and not considered as being able to participate in flexibility yet. The individually modelled type can be based on CCGT and OCGT units which are assumed to have the same technical characteristics towards flexibility as if these would be CCGT or OCGT without CHP capabilities. Additional constraints are that these can typically only deliver downward flexibility (considered as must run) with an energy limit (considered that other processes cannot last a long time without steam). However, it is recognised that various applications exist for CHP and that such a generalisation may be a simplification of reality and subject to further investigation.
- **Battery** (small scale, large scale and future vehicle-to-grid) **and pumped-hydro storage** are the most relevant storage technologies for Belgium and can deliver fast and slow flexibility in both directions without ramp rate limitation. This even means a potential inversion from full offtake to full injection. However, they do face an energy limitation depending on their energy storage capacity. Similar to batteries, pumps and turbines of pumped-storage units can also deliver ramping flexibility, but this is only assumed to be the case when the pump or turbine is dispatched.
- **Renewable generation** is generally considered to have fast and slow downward flexibility (capabilities for upward flexibility are limited as their generation is driven by weather conditions), if they are equipped with appropriate communication and control capabil-

ities. However, the day-ahead forecast and potential forecast errors are taken into account in their contribution.

- **Demand-Side Management** (market response and consumption shifting) can also deliver ramping, fast and slow flexibility, typically only in an upward direction (reduction of consumption). The reaction times depend on the application.
- **Cross-border flexibility** is assumed to be constrained by the remaining available interconnection capacity (ATC) after day-ahead trading. This is calculated based on the hourly import/export schedule following the adequacy assessments. Additionally, a fixed reserve sharing with neighbouring countries is considered in the fast flexibility means based on the volume which is currently considered firm in Elia's reserve capacity dimensioning. Reserve sharing is a TSO-TSO agreement that allows TSOs, under certain conditions, to share part of their reserves between each other.

2.8.4. 'CENTRAL' scenario and sensitivities

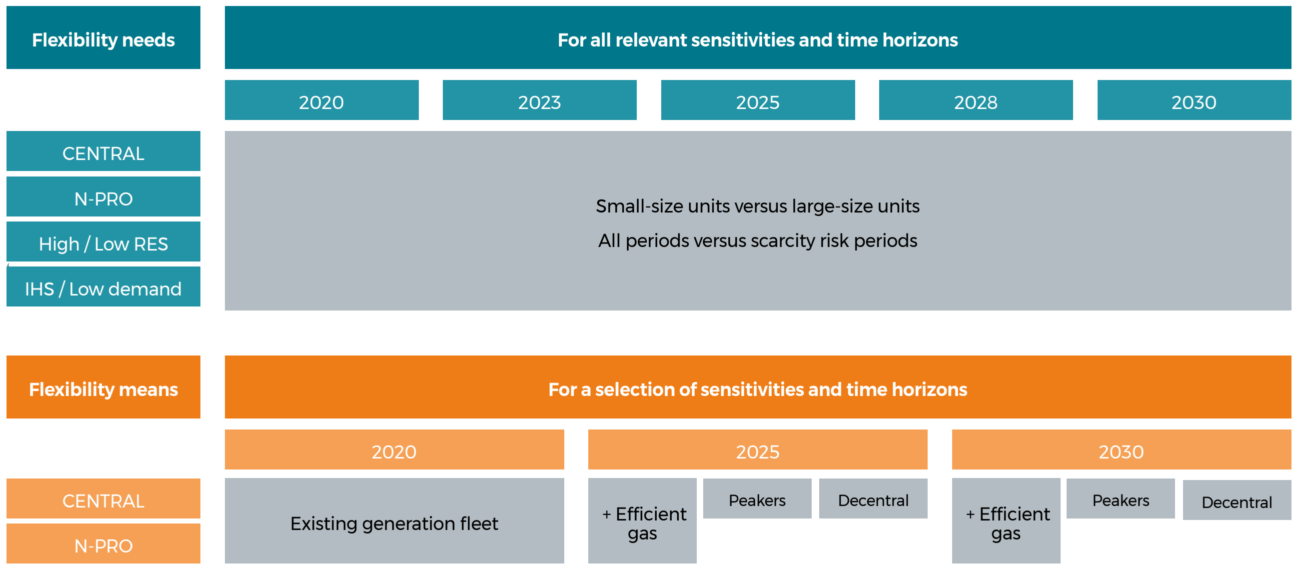
As depicted in Figure 2-59 (up), the flexibility needs are analyzed for the 'CENTRAL' scenario for 2020, 2023, 2025, 2028 and 2030. This includes the same assumptions for demand growth and the installed capacity of onshore and offshore wind power, photovoltaics and must run generators. The installed thermal generation fleet contributing to the forced outages is aligned with the 'CENTRAL' scenario.

Of course, the decision to enter or leave the market and the choice of technology and capacity is decided by the market. However, as these decisions may play a role on the forced outage risk, two particular cases are investigated in which the remaining gap is covered with large-size units of around 600 – 800 MW, and another case in which it is covered with small-size units of around 100 - 200 MW. Without favouring one or the other, this gives insight into the impact of such choice on the flexibility needs. For the same reason, an additional case is analysed with a nuclear prolongation ('N-PRO').

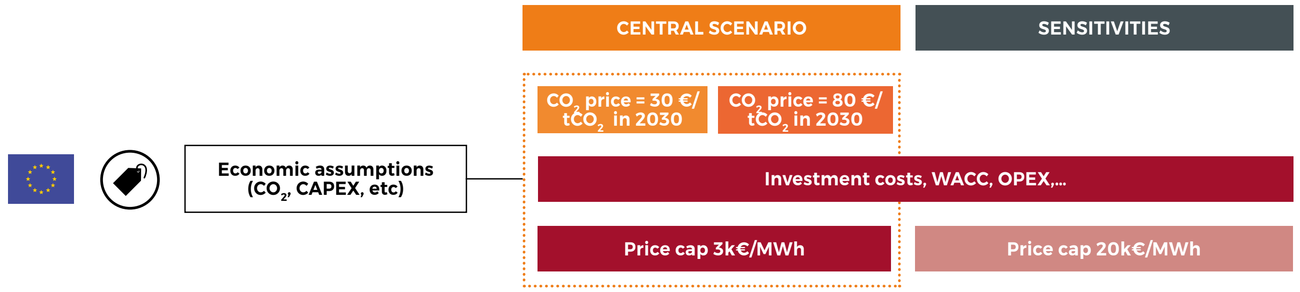
To analyse the available **flexibility means**, a selection of relevant scenarios is analysed. This includes different combinations of technology types in the remaining gap of the structural block are investigated based on their relevance. As different technologies face different capabilities towards flexibility, this may impact the results. An overview is given in Figure 2-59 (down):

- Analysing only 2020, 2025 and 2030 is deemed to be sufficient to grasp the evolution of the flexibility means towards 2030. No specific issues are expected to arise for 2023 and 2028 for the 'CENTRAL' scenario.
- An analysis is conducted for the 'CENTRAL' scenario and the 'N-PRO' sensitivity. As will be shown with the nuclear prolongation, the sensitivities ('High'/'Low RES' and 'IHS'/'Low demand') are not expected to have a significant impact on the (upward) available operational flexibility as non-reserved flexibility is mainly delivered by the marginal generation unit
- For the 'CENTRAL' scenario, a sensitivity is conducted on the remaining gap in the structural block with three extreme cases, i.e. 'Decentral', 'Efficient gas' and 'Peakers' scenario (see Section 4.2.6).

SCENARIO AND SENSITIVITIES FOR THE ANALYSIS OF THE FLEXIBILITY NEEDS (UP) AND AVAILABLE FLEXIBLITY MEANS (DOWN) [FIGURE 2-59]



2.9. Economic assumptions



This study also contains an extensive analysis of the needed capacity by means of an economic viability assessment of the generation units. Therefore, but also in order to perform an economic dispatch simulation and to perform additional economic analyses on the results, several assumptions are to be taken.

On the one hand, the **variable costs of generation** are to be defined. Those are based on three components:

- The **fuel costs** needed to generate electricity – Section 2.9.1;
- The **emissions' costs** to be accounted for depending on the fuel – Section 2.9.2;
- The **variable operation & maintenance costs (VOM)** which are costs associated with the operation of the unit that are proportional to its generation output – Section 2.9.3.

On the other hand, the **fixed costs** of the different technologies also need to be estimated. Those are used to assess the cost of a given scenario and the economic viability of existing and new capacity:

- **Fixed operation and maintenance costs** (FOM) Section 2.9.4.1;
- **Investment costs** (CAPEX) – Section 2.9.4.2;
- **Weighted Average Cost of Capital** (WACC) – Section 2.9.4.3.

Additionally, some other economic assumptions are made to assess the economic viability and capacity mechanisms such as:

- **Cost of capacity mechanisms** (see Section 2.9.5);
- **Maximum price on the market considered in the simulations** (see Section 2.9.6);
- **Revenues from ancillary services** (see Section 2.9.7).

It is important to note that the figures in this section are the reflection of a literature review and public information and might not reflect unit specificities. Future projections are based on public sources.
All costs figures are in real terms in 'Euros 2017'.

2.9.1. Fuel costs

Fuel costs make up the biggest part of the marginal cost of fossil fuel technologies. Variations on fuel prices (coal, gas, oil) are depending on world/regional supply and demand, geopolitics and macro-economic indicators.

The fuel costs used in this study are **based on the most recent 'World Energy Outlook' (WEO)** which was published at the end of 2018 by the International Energy Agency (IEA)[IEA-1]. One scenario is chosen for the future years which corresponds to the 'New Policies' of the WEO for gas, coal and oil prices.

The lignite and nuclear prices are taken from the MAF2018/TYNDP2018 and are assumed to remain stable until 2030:

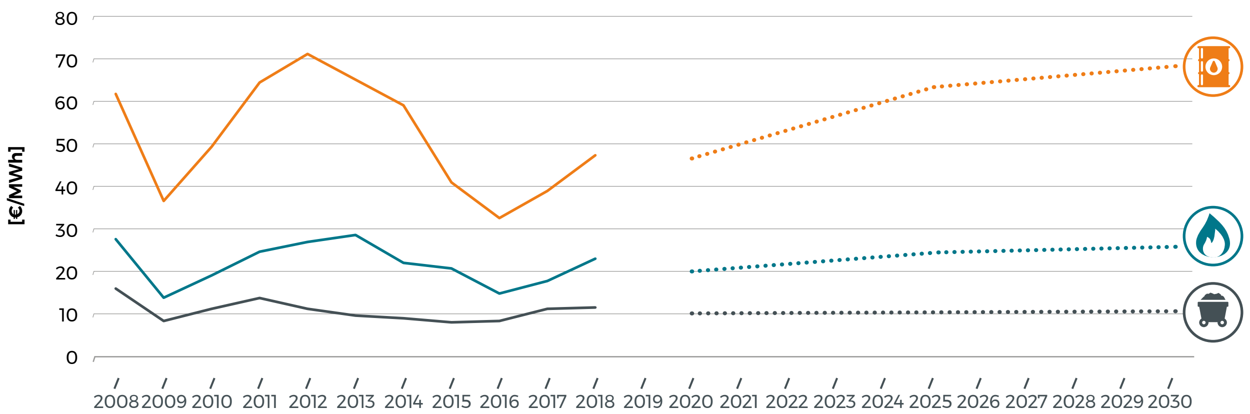
- Nuclear: 0.47 €/GJ
- Lignite: 1.1 €/GJ

Only one price is assumed for all countries in the studied perimeter for gas, oil, coal, lignite and nuclear. This is a simplification given different markets and shipping costs depending on the location although it is the best practice in ENTSO-E studies.

The historical and forecasted prices in Euros/MWh are shown in Figure 2-60.

No alternatives were suggested by stakeholders concerning this choice during the public consultation on the input data. Note that the IEA scenarios also serve as references used for ENTSO-E studies.

NATURAL GAS, COAL AND GASOIL PRICES [FIGURE 2-60]



For historical prices:	For future prices:
Coal: ARA Gas: TTF Gasoil: ARA	Coal: IEA-New Policies Gas: IEA-New Policies Gasoil: IEA-New Policies

BOX 8: IEA SCENARIOS

The **World Energy Outlook** is one of the key deliverables from the International Energy Agency (IEA) that is issued on a yearly basis [IEA-1]. It provides different outlooks in terms of the energy mix, consumption, prices and other analyses for all the regions of the world. It allows the assessment of possible futures of the energy sector applying different policies.

Three scenarios are usually developed by the IEA:

[From the IEA website] [IEA-2]

- ***'New Policies Scenario'*** *of the World Energy Outlook broadly serves as the IEA baseline scenario. It takes account of broad policy commitments and plans that have been announced by countries, including national pledges to reduce greenhouse-gas emissions and plans to phase-out fossil-energy subsidies, even if the measures to implement these commitments have yet to be identified or announced;*
- ***'Current Policies Scenario'*** *assumes no changes in policies from the mid-point of the year of publication (previously called the Reference Scenario);*
- ***'Sustainable Development Scenario (SDS)'*** *sets out an energy pathway consistent with the goal of limiting the global increase in temperature to 2°C by limiting concentration of greenhouse gases in the atmosphere to around 450 parts per million of CO_2'*

In order to capture differences in terms of emissions prices, the 'New Policies' and the 'Sustainable Development' scenarios are used in this study.

International Energy Agency

2.9.2. CO_2 price

The CO_2 price is a key component of the marginal cost for several fossil fuel technologies. The more a unit emits, the higher the contribution of the emissions' cost which will affect its place in the merit order.

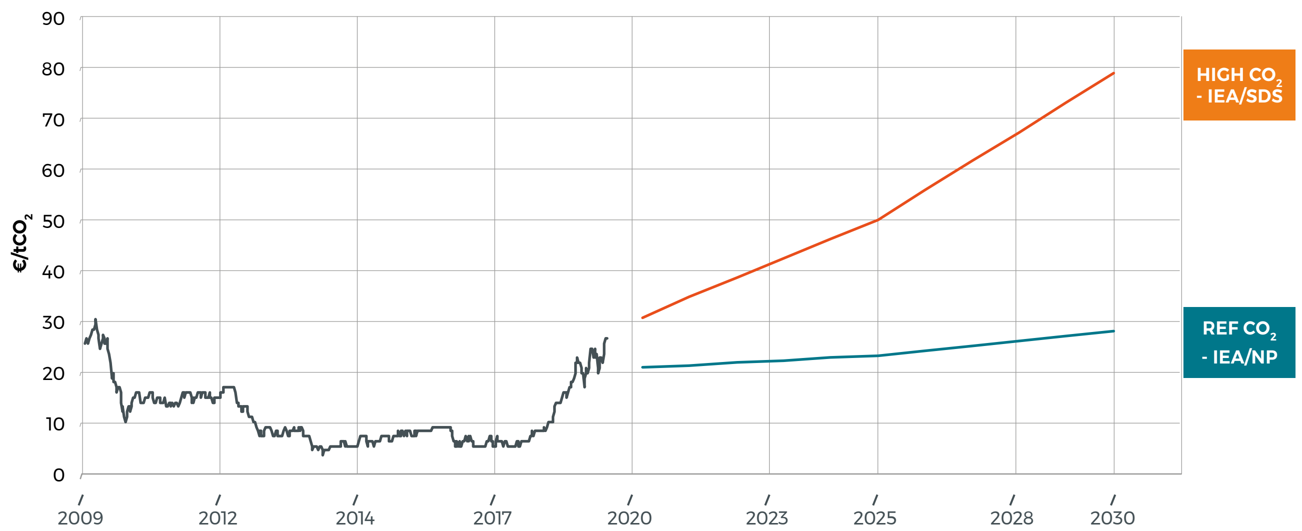
The emissions from the power sector are managed by the **European Trading Emissions System (ETS)** and its price is set by the supply/demand of carbon allowances. Other sectors such as the commercial aviation or energy-intensive industry are also part of the 'cap and trade' system. More information can be found in BOX 3.

Only one scenario was provided ('New Policies' from the IEA) during the public consultation. Following stakeholders comments about the uncertainty of future CO_2 prices, an additional scenario was added with a higher CO_2 price ('SDS' from the IEA). Two different scenarios for carbon prices are therefore used for the economic analysis:

- The 'New Policies' scenario from the IEA reaching a price of around **30 €/tCO_2 in 2030**. This scenario is called **'REF CO_2'** as other sources consulted (BNEF, IHS Markit, EU reference scenario) lead to the same range of prices, around 30 €/tCO_2 in 2030;
- The 'Sustainable Development' scenario with a price of around **80 €/tCO_2** in 2030 is called **'HIGH CO_2'**.

One CO_2 price is used for the whole geographical perimeter considered (also for the UK and NL). Both scenarios are always used for the economic analysis and are shown in Figure 2-61.

CO_2 PRICES: HISTORICAL AND SCENARIOS [FIGURE 2-61]



2.9.3. Other variable costs

The **Variable Operation and Maintenance (VOM) costs** of units are costs that are linked to the electrical output of a generation facility (excluding fuel, emissions' and personnel costs). The VOM costs are taken from a study by the Joint Research Centre of the European Commission [EUC-5] for gas units and from the ENTSO-E database for the other generation units, as shown in Figure 2-62

VARIABLE OPERATION AND MAINTENANCE (VOM) COSTS FOR THERMAL UNITS [FIGURE 2-62]

	VARIABLE OPERATION AND MAINTENANCE COSTS [€/MWH]
CCGT	2
OCGT	11
Nuclear	9
Coal/Lignite/Biomass	3 to 4

Sources: [EUC-5][ENT-6]

2.9.4. Fixed costs of existing and new capacity

Fixed costs can be split in two categories:

- **Fixed Operation and Maintenance (FOM)** are costs needed to operate or to make available any generation, storage or market response capacity. Those costs are not depending on the output of the unit;
- The **investment annuity** for new capacity which include the annualised CAPEX costs and a certain weighted average cost of capital (WACC).

For each capacity considered in the economic analysis, an annualised fixed cost is used based on the above components.

2.9.4.1. FIXED O&M

The Fixed Operation and Maintenance (FOM) costs do not directly depend on the capacity usage. The cost of a technical lifetime extension of the capacity is not included either and should be taken into account on top of the FOM costs. Those are dealt with in the next section about CAPital Expenditure (CAPEX).

FOM assumptions are based on several sources indicated in Figure 2-62. Those costs are key to evaluate the viability of existing capacity as owners could decide to shut down or mothball capacities if the revenues from the market do not cover those costs.

A range of values will be used as the FOM is unit dependent.

2.9.4.2. CAPEX

The investments in a new capacity or the life-time extension of existing capacity are quantified in the CAPital Expenditure (CAPEX) figures.

For new capacity, those costs represent the total investment (engineering, procurement and construction (EPC), construction works and other owner's costs).

Several sources were used for new capacity and resulted in a range of values. Those are mentioned in Figure 2-62.

For capacity requiring life time extension, the costs represent the different works, parts of the installation to be replaced, in order to extend its life-time.

Only existing CCGT and OCGT that are older than 25 years for a given year are assumed to require a life-time extension (excluding the CCGT unit of Seraing which is assumed as requiring no extension costs for the simulated horizon). All the other existing capacity in the structural block (storage, market response, CHP, turbojets...) will be assessed without considering additional refurbishment costs (which might not be the case in reality).

Ranges for CCGT and OCGT refurbishment costs are based on past public figures for the Belgian market. It is important to note that such cost may vary depending on the maintenance policy of the unit, its operating mode, the amount of starts, the technology... This is the reason to work with ranges although only the minimum value (hence the most optimistic) will be used for the economic viability check.

2.9.4.3. WACC

The Weighted Average Cost of Capital (WACC) might differ depending on the investor's risk appetite, market conditions, volatility of revenues and other factors. The higher the revenues volatility and unpredictability, the higher the risk, and hence the higher the WACC. In order to capture how the market design can impact the investor's risk, two WACC values are used:

- A **WACC of 7.5%** is applied when the investment is in a market design resulting in more predictable and stable revenue streams (e.g. EM+CRM);
- A **WACC of 10%** is applied when the investment is in a market design with less predictable revenue streams (e.g. EOM with or without strategic reserves).

All new capacity (of any technology) will be subject to the same WACC. In reality, depending on the expected revenues and volatility, this might differ.

The above assumptions are based on a study by RTE (the French TSO) on capacity mechanisms [RTE-4] and falls in the range of many other studies using WACC assumptions.

2.9.4.4. SUMMARY TABLE OF FIXED COSTS

The Figure 2-62 gives an overview of the assumptions for CAPEX and the lifetime of the investment considered for this study.

INVESTMENT AND FIXED COSTS FOR EACH TECHNOLOGY [FIGURE 2-63]

Technologies part of the structural block (economic viability and assessment)		Applies to	CAPEX or extension cost [€/kW]			FOM [€/kW]			Investment economic lifetime [years]	Sources
			Min	Average	Max	Min	Average	Max		
Existing (assumed no extension costs)	CCGT	Existing units <25y	-	-	-	15	20	25	-	a
	OCGT		-	-	-	5	10	15	-	a
	CHP	All existing units	-	-	-	50	60	70	-	a
	Turbojets	All existing units	-	-	-	10	15	20	-	a
	Market Response	All existing units	-	-	-	5	10	15	-	b
	Pumped Storage	All existing units	-	-	-	15	20	25	-	c
Existing (assuming extension costs needed)	CCGT	Existing units >25y	90	130	160	15	20	25	15	d
	OCGT		60	80	100	10	15	20	15	d
New	Diesels	New capacity	300	400	500	10	15	20	15	e
	Gas engines	New capacity	400	500	600	10	15	20	15	f
	CCGT	New capacity	600	750	900	15	20	25	20	a
	OCGT	New capacity	400	500	600	5	10	15	20	a
	CHP	New capacity	700	1000	1200	50	60	70	20	a
	Market Response	New capacity	10	20	50	5	10	15	10	b
	Batteries/Storage	New capacity (1h storage)	70	100	130	5	10	15	10	g
		New capacity (3h storage)	500	700	1000	5	10	15	10	h
		Enabling new V2G	130	150	170	5	10	15	10	i
	Pumped Storage - new unit	New unit in Coo	900	1000	1100	15	20	25	25	j
Data used only for the economic assessment										
Extension	Nuclear	Only 2 units (sensitivity only)	-	800	-	-	120	-	10	k
Out of market	Cost of existing in SR	Out of market exisiting capacity (and up to 500 MW new capacity)	-	-	-	-	36	-	-	l
	Cost of new in SR	Out of market new capacity	-	-	-	-	50	-	-	m

Minimum value is used for the economic viability check as threshold.
Average is used for the economic assessment (net welfare calculation).

Sources

a ETRI, ASSET, with a range around it
b CRE/e-cube
c CREG/Deloitte
d Review of past project's public information
e BEIS + own research
f BEIS
g ASSET
h Tesla PowerWall cost
i Assumed to be the cost of smart meter
j ENGIE - Coo3 public information
k ENGIE, D12 extension, BNB/CREG
l Historical SR prices on Elia website
m Assumed higher because new capacity needed

2.9.5. Cost of capacity mechanisms

In general, the cost of a capacity mechanism is not straightforward to estimate. The net cost of the mechanism, i.e. when not taking into account other welfare effects, may differ between a strategic reserve (SR) and a market-wide capacity remuneration mechanism (CRM).

Firstly, the cost of market-wide capacity mechanisms depends on many aspects such as the overall design of the mechanism (e.g. how is the auction cleared, are there one or more pricecaps, how is the participation of foreign capacity arranged, how much capacity should be found in a first Y-4 auction and how much in a second Y-1 auction, etc.) and the technologies offered and finally selected through the CRM and their respective contract length (how many existing or new capacity, is existing capacity being refurbished, how many DSR will clear in the auction). Notwithstanding these difficulties, PWC provided a reasoned estimate of the cost of a market-wide capacity mechanism for Belgium in its study of March 2018 for the Federal Public Service of Economy [PWC-1]. As the overall need for new capacity to be fostered by the CRM has not substantially changed when looking at the results of this study compared to the assumptions used by PWC at that time, the order of magnitude of the cost of the capacity mechanism as determined by PWC is used in this study as an indicator for the cost of a CRM. PWC put forward a base case cost of about 350 M€/year. According to the analysed sensitivities the amount can vary greatly both up- and downwards. A range of 300-500 M€/year appears to capture a large part of the analysed range, thereby prudently leaving out the more optimistic outcomes. As an order of magnitude this yields a cost of 3-5 €/MWh which is assumed a simple rate on consumed energy to finance the CRM. Note, however, that the financing mechanism for the Belgian CRM is yet to be determined.

Secondly, an estimate of the cost of a strategic reserve depends greatly on the type of assets that are contracted. Typically, in Belgium both out-of-market generation assets and out-of-market demand response are eligible. Their cost structure is likely to differ. Also, the cost of DSR participating in a strategic reserve may be different for capacity that already participated in the mechanism or new (out-of-market) DSR that would be developed within the mechanism itself.

Based on public historical cost data [ELI-15] of strategic reserve in Belgium a cost of 10 €/MW/h could serve as an appropriate estimate. As these costs are based on a 5-month winter period, this results in about 36 €/kW for both generation and DSR. If large volumes of new (out-of-market) DSR would be required, e.g. beyond a volume of 500 MW, a higher cost may be justified. In this study 50 €/kW is assumed.

2.9.6. Market price cap assumptions

The market modelling used for this study requires a price cap, i.e. a maximum energy price at which the modelled market can clear. The reference price cap throughout this study is assumed to be 3000 €/MWh. This corresponds to the European harmonized maximum clearing price for the Day-Ahead market in Belgium and all other modelled markets as set according to a decision from ACER upon the proposal by the NEMOs (i.e. the power exchanges) following Art. 41 of the CACM guidelines [EUR-1].

Although the prevailing day ahead price cap is currently set at 3 000 €/MWh, the rules governing this price cap also foresee that it could increase over time via an automatic adjustment mechanism. In particular, when a price of 60% of the prevailing price cap is reached in one of the concerned markets, the price cap increases by 1 000 €/MWh. In theory, the price cap could increase over time until it is high enough to cover the Value of Lost Load (VoLL). Estimations on the VoLL vary greatly, but could easily reach ranges 10000 or 20000 €/MWh (or even go beyond, depending on the estimate and the methodology used)[PLN-2] [PLN-3].

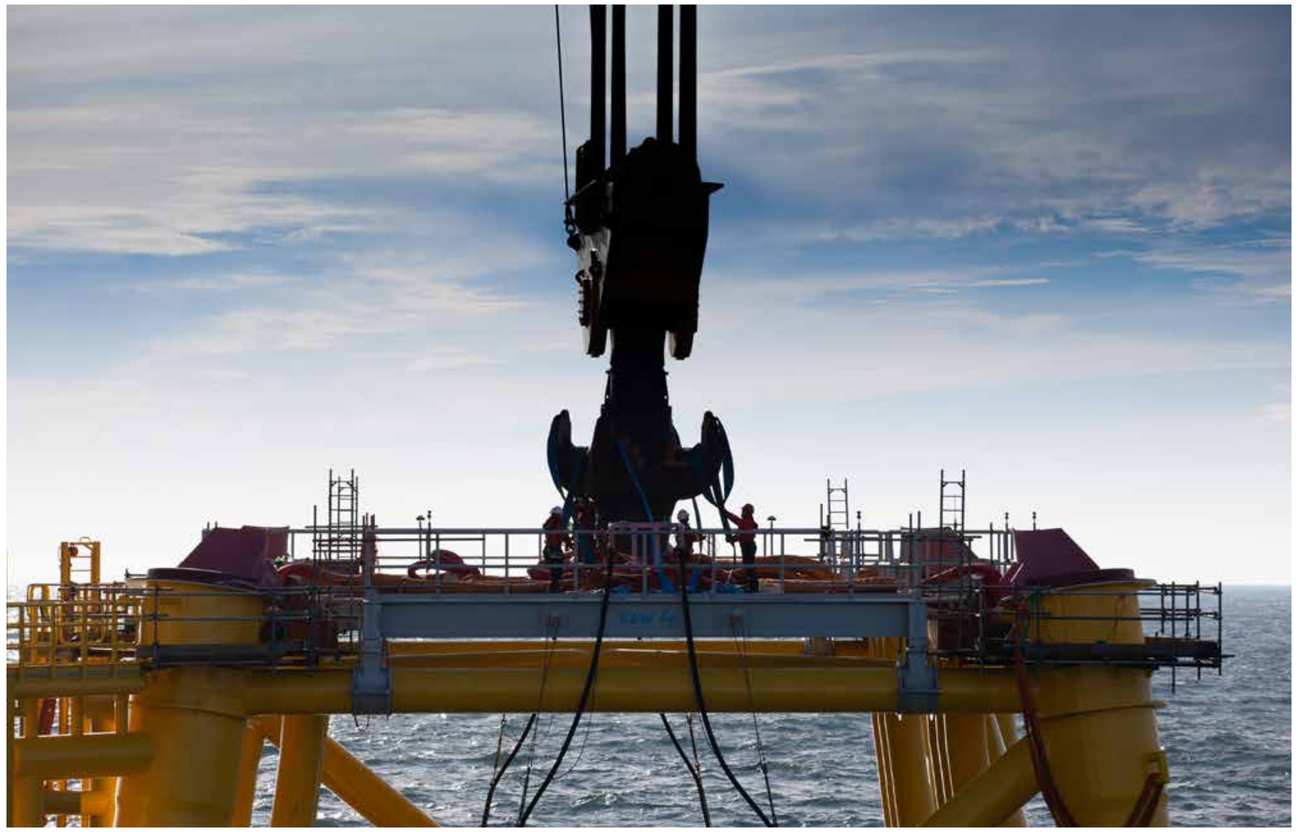
Given the above mechanism that could result in an increasing price cap, a sensitivity has been calculated in this study that assumes that the price cap would be 20000 €/MWh, i.e. a value in the order of magnitude of what the VoLL could be.

2.9.7. Ancillary services' revenues' assessment

The revenues earned by capacity in the energy market as calculated via the ANTARES model exclude any revenues that capacity could have by participating in the ancillary service markets. Obviously, not all capacity participates in these markets as either they may technically not be capable of delivering the respective services and/or the volumes (MW) needed are far below the level of installed capacity (order of magnitude of 1 GW compared to a peak load of about 14 GW to be covered). Furthermore, it should be kept in mind that participation in ancillary service products such as FCR, aFRR and mFRR requires capacity to be available while not necessarily being used. Although activation costs can be covered in some ancillary service products and depending on the market design could result in an extra revenue, by being reserved for those products the energy that could be delivered by the capacity can no longer be sold in the energy (i.e. commodity) market and therefore no revenue can be earned there. This implies that there is a trade-off to be made and that by opting for participation (and revenues) from the ancillary services market, the opportunity for revenues from the energy market is lost. So one should remain careful not to double-count some revenues.

At overall market level the reservation costs of ancillary services in any case remains limited. In 2017 and 2018 the total reservation cost for FCR, aFRR and mFRR amounted to approximately 70 M€/yr and 125 M€/yr, respectively. Note that 2018 was characterized by particularly higher prices due to the specific winter situation. Assuming an installed capacity in Belgium of about 15 GW, this would only amount to 4 to 8.5 €/kW/yr, while bearing in mind that this may come with an opportunity loss of not capturing revenues from the energy (i.e. commodity) market.

With respect to the future it should be taken into account that part of the flexibility will increasingly be sourced abroad (cf. already the case today for some reserve products) and it is not expected that the order of magnitude in terms of volume would dramatically change in the future. There may be reasons to think that such revenue could even reduce as – once the inflexible nuclear fleet has disappeared and been replaced by (at least partly) flexible capacity – competitive pressure could increase and may dampen prices for flexibility. However, such effects and the overall value of flexibility remain difficult to estimate and should be put together with other effects, such as the cross-border opening of balancing markets, etc.



3 Methodology

Elia continuously improves its methods and data in order to include the latest developments and trends. This study is based on the **most advanced models and tools available** and uses the expertise shared between TSOs at European and regional level from their adequacy and economic studies. For the adequacy study, the **methodology is fully in line with the one used for the European Adequacy assessment** (MAF). It is complemented with new developments and analyses which are not yet introduced in the European assessment and gives a detailed focus on Belgium by assessing a large amount of sensitivities, as requested by stakeholders.

Elia developed a new methodology to conduct the flexibility assessment. The methodology is based on an analysis of the flexibility needs (based on variable generation and demand data, as well as forced outages) and the available flexibility means in the system. The methodology combines best practices of different existing approaches, and can be considered as novel and state-of-the-art what concerns implementation by TSOs.

Hourly electricity market simulations of 21 European countries are at the core of the analysis. Based on the scenarios defined in the previous chapter, a large amount of sensitivities will be able to cover uncertainties in terms of generation fleet, demand, storage, interconnections, fuel prices, etc. Assessing indicators resulting from those simulations will help quantifying the adequacy requirements, the flexibility needs and the resulting economic indicators. After defining the scenarios and sensitivities that will be investigated, the methodology used in this study consists of the following steps.

The **first step** evaluates **the flexibility needs**. Besides determining the general flexibility needs during all periods, a separate analysis is conducted examining the minimum flexibility needs which are required during scarcity situations. While the first will be compared with available flexibility means in the fifth step, the second is integrated directly as a parameter in the adequacy assessment. Indeed, a system should not only be adequate in perfect foresight, but should also be able to cope with (unexpected) variations of demand and generation. In this way, forced outages and prediction errors after day-ahead are covered in the adequacy assessment.

The **second step** consists of an adequacy assessment to **evaluate the capacity needed** in Belgium following policy choices on RES, nuclear capacity and consumption. The resulting capacity needs will be called the '**structural block**'. Several sensitivities will be applied as requested by stakeholders. Afterwards the capacity needed after considering imports, CHP generation, market response and storage (not fully policy driven technologies but where ambitions were set by policy makers) will be calculated through the adequacy assessment. Several sensitivities will also be performed on the above volume as requested by stakeholders.

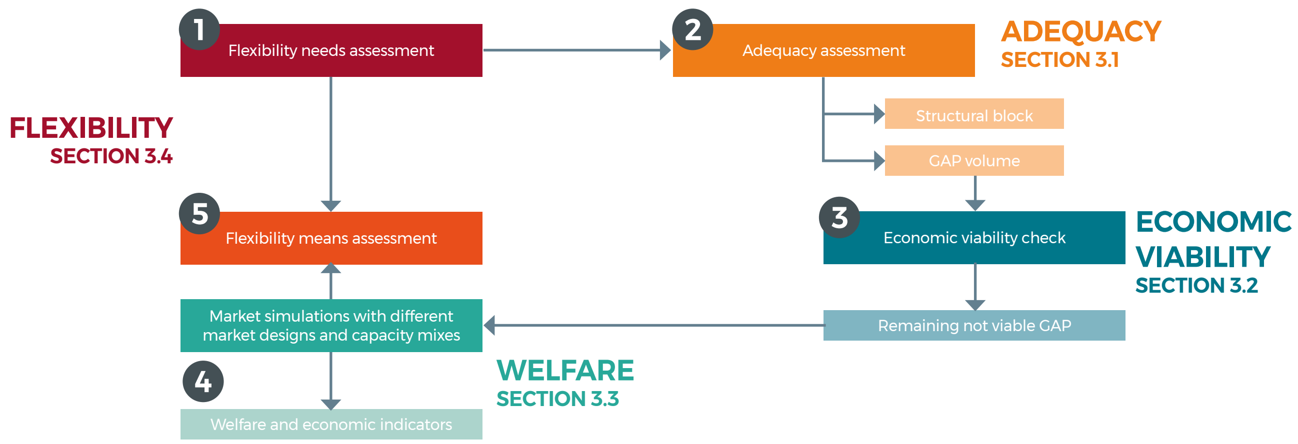
The remaining volume will be called the '**GAP volume**' and can be filled by existing capacity not yet considered (CCGT/classical, OCGT, turbojets) or new capacity of any kind (including storage and market response). The adequacy assessment methodology is detailed in Section 3.1.

After calculating the GAP volume, as a **third step**, an **economic viability check** under the current market design will be performed on all structural block capacities to assess whether their revenues from the market are sufficient to allow them to remain in the market. Moreover, assumed new capacity in the market (market response and storage) will also be assessed. Additionally if new capacity (of any kind) is viable, it will also be identified in this step. The **remaining 'not-viable GAP'** after the viability check (if any) consists of the capacity that would in theory not be invested by the market (unless additional support is given). The economic viability assessment is explained in Section 3.2.

The **fourth step** concerns the **evaluation of the economics of different capacity mixes and market designs** to fill the 'not-viable GAP' (in or out of the market). Indicators such as welfare, wholesale prices, investment costs and imports/exports will be assessed. The different indicators are detailed in Section 3.3.

In the **fifth step**, the available **flexibility means** will be evaluated to check whether the system can cope with the flexibility needs at any time. The output of the market simulation is used and for every hour the ability of the system to provide the required flexibility is assessed (thus also in periods in which it is not enforced in the adequacy assessment). This allows Elia to check if measures are needed to ensure the operational availability of flexibility. This part is detailed in Section 3.4.

STUDY METHODOLOGY [FIGURE 3-1]



3.1. Adequacy

3.1.1. Definitions of 'structural block', 'GAP volume' and 'not-viable GAP'

The volume sought in this study is quantified following three levels (assumed 100% always available and 100% flexible):

1 The 'structural block';
2 The 'GAP volume';
3 The 'not viable GAP'.

Those volumes are quantified to respect **the legal adequacy criteria** (reliability standard) of the Belgian electricity system (see Section 1.1.2 for more information).

The **'structural block'** is the capacity that should complement the following capacity sources assumed to be present in the market in any case (via support mechanisms and legal provisions):

- The **renewable energy sources** (onshore/offshore wind, solar and biomass) following the assumptions described in Section 2.5.1.3;
- The **nuclear capacity** as described in Section 2.5.1.2 (which follows the current law for nuclear phase-out);

The '**GAP volume**' is the capacity that should complement the following capacities on top of **renewable energy sources** and **nuclear capacity** (covered by the structural block):

- The **cross-border imports towards Belgium** estimated for different time horizons (exchanges between countries are decided by the economic dispatch model used (see Section 2.7)). The capacity of other countries to be able to provide this energy is therefore evaluated by the model on an hourly basis;
- The **Combined Heat & Power (CHP)** generation following the assumptions described in Section 2.5.2.3;
- **All existing and new market response (assumed in the 'Energy Pact')** including the existing volume participating in the ancillary services as described in Section 2.5.2.2;
- **The storage capacity (existing and new) as assumed in the 'Energy Pact'.**

Finally, the '**not viable GAP**' is the shortage in capacity that would occur in Belgium resulting from an **economic viability check** on existing and any kind of new capacity (on top of the capacity already assumed by the 'Energy Pact'). This can consist of: CHP, market response, storage facilities, existing & new thermal. The process followed for the 'not viable GAP' evaluation is described in Section 3.2.1.

BOX 9: COMPARISON WITH PAST STUDIES

In the Elia study on '**Adequacy and Flexibility for the 2017-2027 period**', published in April 2016, the term 'structural block' was introduced and was referring to a 100% theoretically available generation, storage or demand response capacity and corresponds to the 'GAP volume' in this study.

In the Elia study '**Electricity scenarios for Belgium towards 2050**', published in November 2017, the term 'thermal block' was introduced and was referring to thermal capacity (taking into account an outage rate). This volume can be compared to the 'GAP volume' to which a forced outage rate between 5 to 9 % is to be applied. 3.1.2.

STRUCTURAL BLOCK, GAP VOLUME AND NOT VIABLE GAP DEFINITION [FIGURE 3-2]

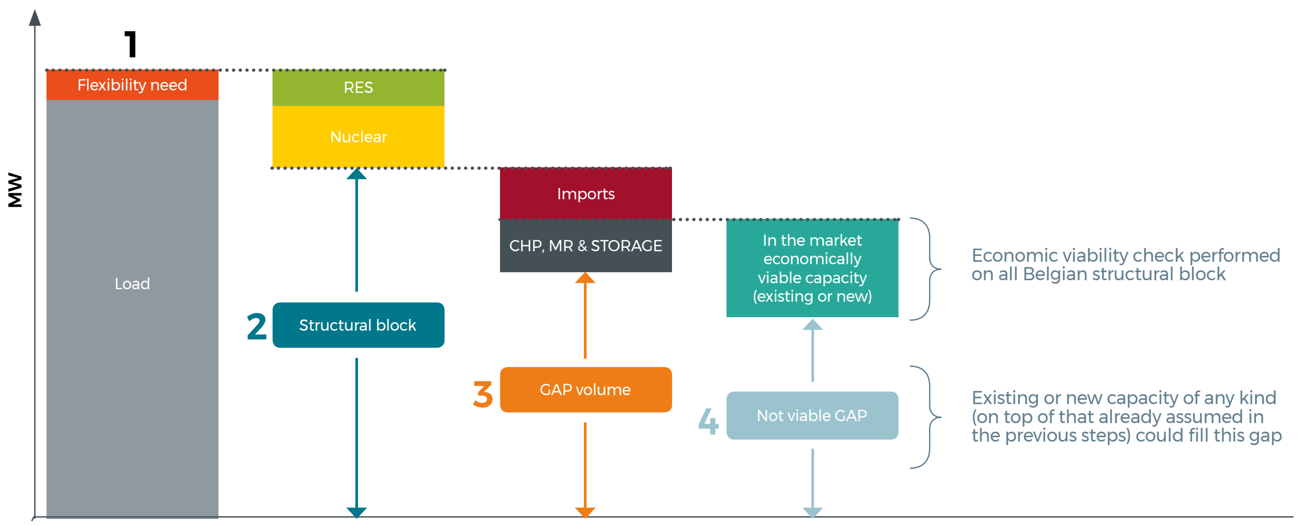
WHAT IS CALCULATED ?

1 The assessment starts from the evaluation of the consumption for Belgium increased by the flexibility needs during scarcity risk periods identified in the flexibility assessment.

2 The **structural block** is the capacity needed **(100% available/flexible)** to ensure an adequate system when adding the flexibility needs to the consumption during scarcity risk periods and deducting the renewable generation and nuclear.

3 The **GAP** is the capacity needed **(100% available/flexible)** in Belgium to ensure an adequate system when deducting the contribution of CHP, market response, storage (without viability check) and imports from the structural block.

4 The not viable GAP **(100% available/flexible)** is the shortage in capacity that would prevail in market in **Belgium** resulting from an economic viability check on existing and new capacity.



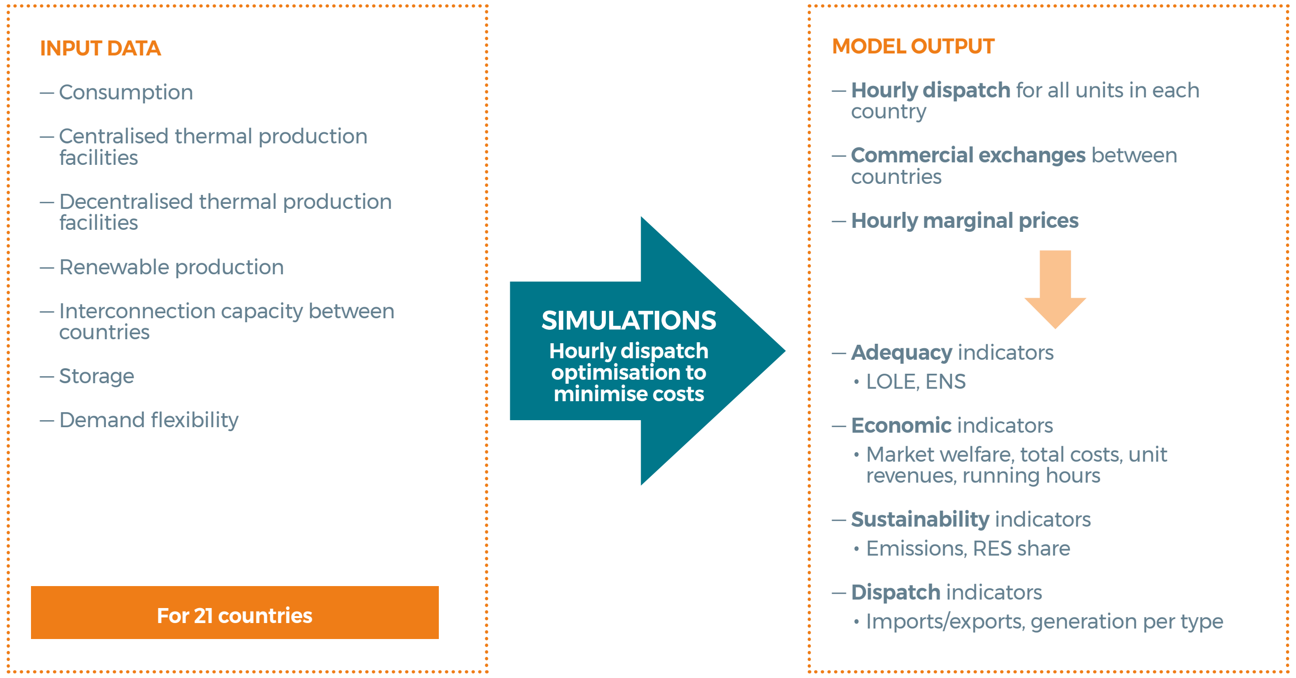
3.1.2. Hourly electricity market model

An electricity market simulator developed by RTE, called ANTARES [RTE-2], is used to perform the electricity market and adequacy simulations. ANTARES calculates the optimal unit commitment and generation dispatch from an economical perspective, i.e. minimising the generation costs while respecting the technical constraints of each generation unit. The dispatchable generation (including thermal & hydro generation, storage facilities and demand side response) and the resulting cross-border market exchanges constitute the decision variables of an optimisation problem, which essentially aims to minimise the total operational costs of the system.

In order to simulate the European electricity market, several assumptions and parameters must be defined. These elements are described in Chapter 2.

Figure 3-3 gives an overview of the input and output data of the model.

INPUT AND OUTPUT DATA FOR THE MODEL [FIGURE 3-3]



The main input data for each country are:

- The hourly consumption profiles;
- The installed capacity of thermal generation facilities with their associated availability parameters or hourly production profiles for distributed generation, and with their associated marginal cost;
- The installed PV, wind and hydroelectric capacity and associated production profiles based on the climate years;
- The installed storage facilities (batteries and V2G) with their associated efficiency and reservoir constraints;
- The installed demand flexibility/market response capacity;
- The interconnection capacity (by using the flow-based methodology or fixed bilateral exchange capacities between countries (NTC method)).

These data are introduced by means of hourly or monthly time series or are established for a whole year.

The inputs provided to the tool enable the simulation of the market and determine the 'future states' based on a random selection from the associated time series. As described in Section 3.1.3.1, the climatic data relating to a given variable for a specific year is always combined with data from the same climatic year for all other variables and applied to all the countries.

Based on these inputs, the optimisation problems are solved with an hourly time step and a weekly timeframe, making the assumption of perfect information at this time horizon but assuming that the evolution of load and RES is not known beyond this horizon. Fifty-two weekly optimisation problems are therefore solved in a row for each 'Monte-Carlo' year.

The optimal dispatch is based on market bids reflecting the marginal costs of each unit [€/MWh]. When this optimum is found, the following output can be analysed:

- Locational marginal prices based on market bids (in this study locations are market zones);
- Hourly dispatch of all the units;
- Hourly commercial exchanges between market zones.

Following the simulations, the output data provided by the model enables a large range of indicators to be determined:

- Adequacy indicators (LOLE – Loss of Load Expectation, EENS – Expected Energy Not Served);
- Economic indicators (welfare, total costs, unit revenues, running hours,...);
- Sustainability indicators (emissions, RES shares);
- Dispatch indicators (imports/exports, generated energy per fuel/technology).

It is important to highlight a number of modelling assumptions to correctly interpret the results:

- Hourly simulations of the market are performed on the basis that all the energy is sold and bought in the day-ahead market. Integrating long and/or real-time markets in such a model is not straightforward. Forward markets are assumed to act as financial instruments anticipating day-ahead/real-time price. Depending on the trading strategy and actual market conditions an arbitrage value may exist between different time frames;
- An optimal solution is sought in order to minimise the total cost of operation of the whole simulated system;
- Perfect foresight is considered for renewable production, consumption and unit availability (known one week in advance following an ex-ante draw). This is not the case in reality, where forecasting deviations and unexpected unit outages are happening and need to be covered by the system. Note that for each market zone (except Belgium), in order to cope with such events, a part of the capacity is reserved for balancing purposes and cannot be dispatched by the model. This is inline with the MAF methodology. For Belgium a volume is reserved to cope with flexibility requirements during scarcity situations and is calculated in Section 4.3;
- A perfect market is assumed (no market power, bidding strategies,...) in the scope of the model;
- Pumped storage units, batteries and market response are dispatched/activated in order to minimise the total cost of operation of the system. In reality this could be different as they could be used to net a certain load in a smaller zone or to react to other signals. The modelling approach also assumes that price signals are driving the economic dispatch of those technologies;
- Prices calculated in the model are based on the marginal price/activation of each unit/technology;
- The efficiency of each thermal unit is considered fixed and independent of the loading of the unit. In reality this efficiency depends on the generated power.

How is the Unit Commitment and Economic Dispatch performed?
More information available in Appendix E

3.1.3. Adequacy assessment

The methodology used for the adequacy assessment is **fully in line with the methodology used for the European adequacy assessment in the framework of ENTSO-E. It is also the same as the one used for the volume determination of the Strategic Reserve performed each year according to the Electricity Law**. A detailed description of the methodology is also available in Chapter 2 (pages 41 to 46) of the latest report on the need for Strategic Reserves for winter 2019-20 [ELI-13].

An adequacy simulation consists of three steps (performed for each scenario and sensitivity of each time horizon):

1 The **first step is the definition of future possible states (or 'Monte-Carlo year')** covering the uncertainty of the production fleet (technical failures) and weather conditions (impacting RES generation and demand profiles due to thermo-sensitivity effects). Each of these future states is based on historical data about uncertainties. This step is defined in more detail in Section 3.1.3.1;

2 The **second step** is the identification of **structural shortage periods**, i.e. moments during which the electricity production on the market is not sufficient to satisfy the electricity demand. **Hourly market simulations** are performed to quantify deficit hours for the entire future state. More information is available in Section 3.1.3.2;

3 The **third step** is to assess the **additional capacity needed (100% available)** to satisfy the legal adequacy criteria as defined in Section 1.1.2. This capacity is evaluated with an iterative process defined in Section 3.1.3.3.

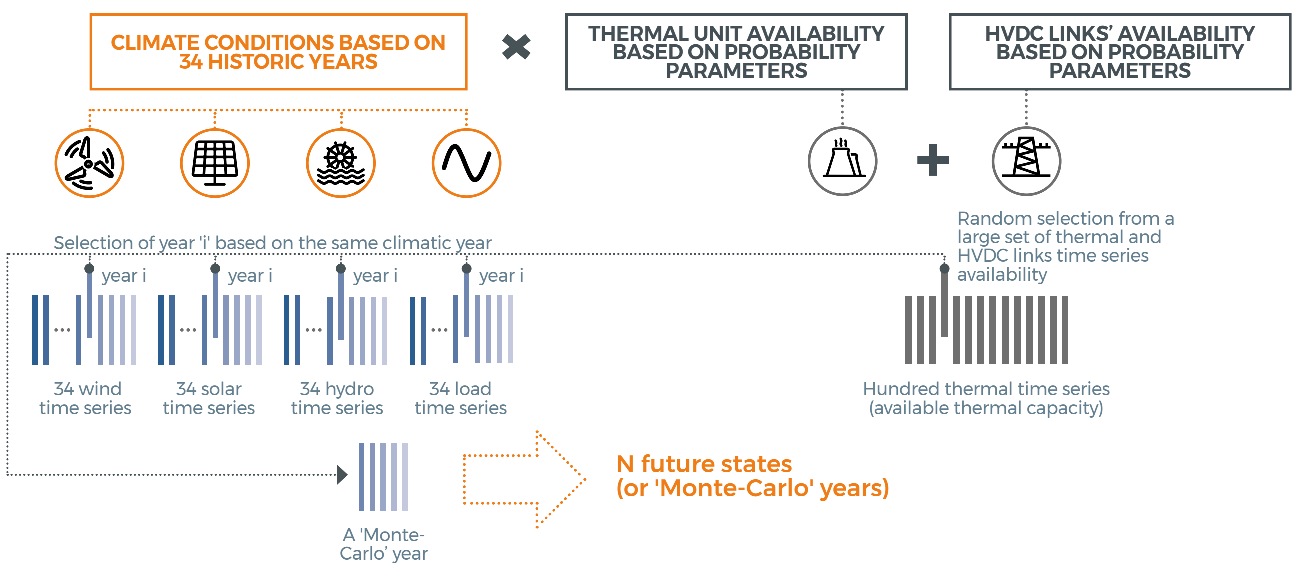
3.1.3.1. DEFINITION OF FUTURE STATES

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 consumption by taking into account the 'thermosensitivity' effect, see Appendix E.2. 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, see Appendix E.1. 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.

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'.

GENERATION OF A 'MONTE CARLO' YEAR [FIGURE 3-4]



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.

As described in Appendix E.1, the market model used to perform the adequacy simulation (ANTARES) is the same as the one used for the market outputs (see Appendix E.1 for more detailed information). The main differences between adequacy simulations and market simulations are:

- **The amount of future states:** The adequacy study simulates the climate dataset several times with a different unavailability draw for each future state in order to obtain a sufficient accuracy on the LOLE indicator. The market simulation simulates the set once with different unavailability draws for each future state;
- **The output analysed:** The adequacy simulation looks only at the moments of structural shortage while the market study derives economic, sustainability and dispatch data.

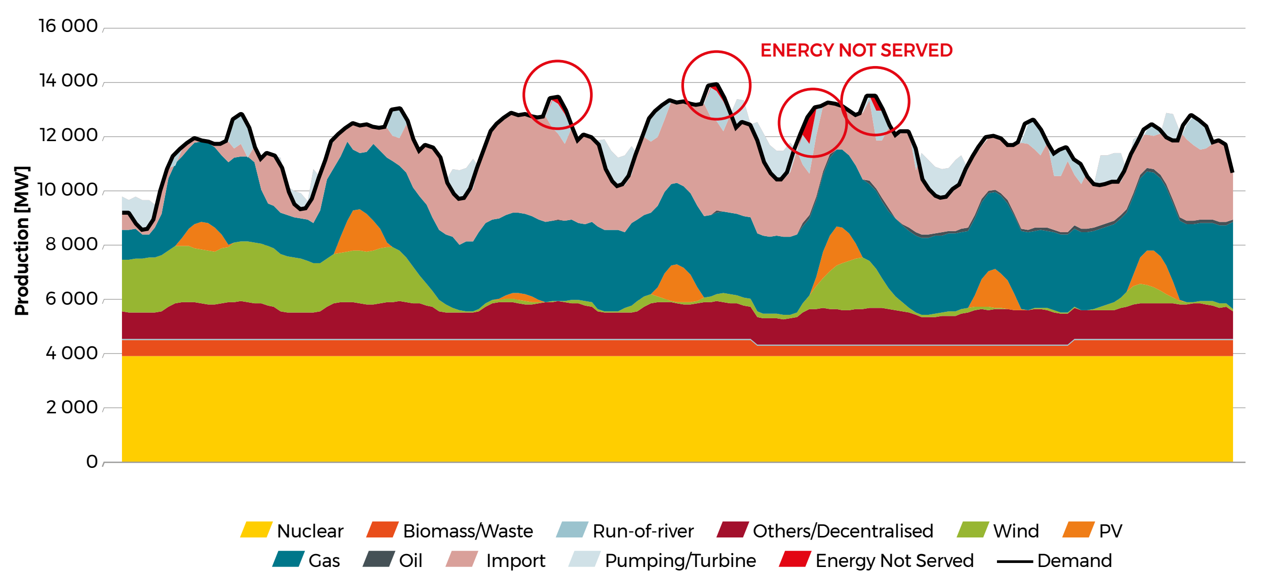
What is the "Monte-Carlo" method?
More information available in Appendix E

3.1.3.2. IDENTIFICATION OF STRUCTURAL SHORTAGE PERIODS

The second part of each iteration step involves identifying periods of structural shortage, i.e. times when available generation capacity (including storage and market response) and imports are insufficient to meet demand. To this end, the output of the probabilistic market simulation is assessed on an hour-by-hour basis by simulating the European electricity market.

Figure 3-5 illustrates how consumption is covered by the available generation facilities and imports for every hour of the week. If, for a given hour, the combination of generation capacity, storage, imports and market response falls short (by 1 MW or more) of the capacity required to meet demand, this corresponds to one hour of structural shortage, or an 'energy not served' (ENS) situation. Within the 'Monte Carlo' approach, the average number of such hours for one 'Monte Carlo' year is referred to as loss of load expectation (LOLE). Figure 3-5 shows the energy that cannot be supplied by combining domestic generation, storage facilities, market response and imports.

EXAMPLE OF A SIMULATION DISPATCH OUTPUT FOR A WEEK IN BELGIUM [FIGURE 3-5]



3.1.3.3. ITERATIVE PROCESS FOR CALCULATING THE ADDITIONAL CAPACITY NEED

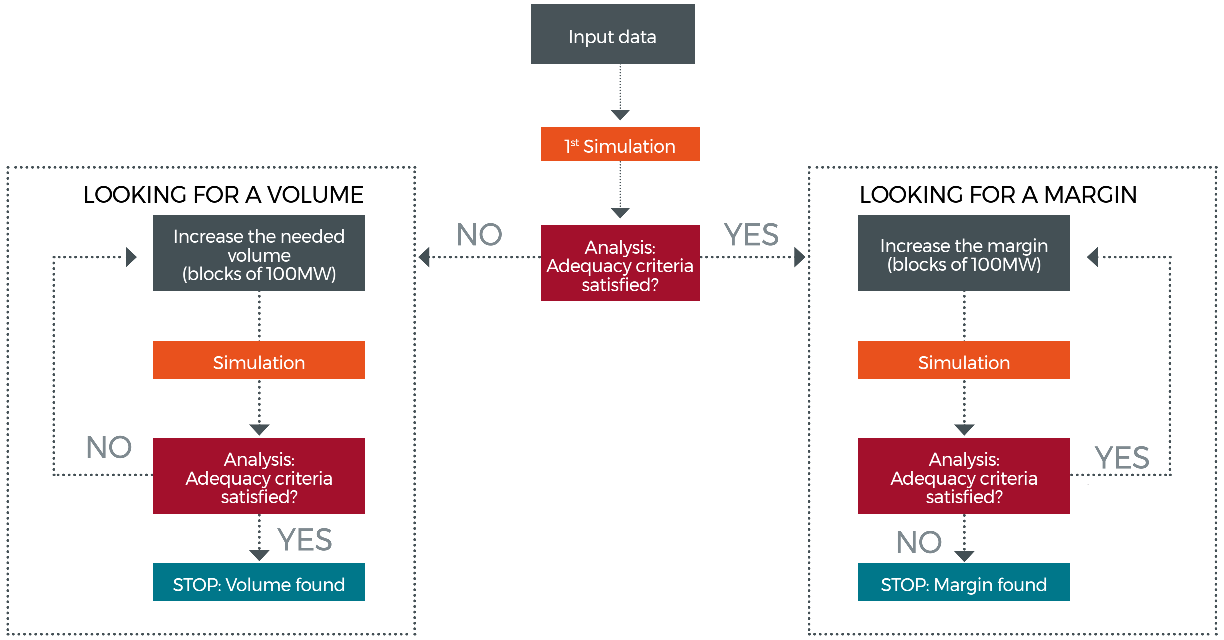
Once the moments of structural deficit are identified for each 'Monte Carlo year', the distribution of these (quantified in hours) is established. On this basis, the adequacy criteria of the electrical system are evaluated and compared to the legal adequacy criteria (reliability standard).

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

The block size of 100 MW was chosen to be as small as possible, while still ensuring statistically robust results for the determination of the volume. Especially when searching for the tail of the distribution (e.g. P95 criterion), this statistical robustness is a limiting factor. Choosing a smaller step size might lead to a calculation result that differs depending on the random seeding of the model [ELI-16]. 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.

The iterative process applied for determining the 'not viable GAP' follows a different approach as it includes a viability assessment of the existing and new capacity. This is further explained in Section 3.2.1.

ITERATIVE PROCESS FOR 'STRUCTURAL BLOCK' AND 'GAP VOLUME' IDENTIFICATION TO SATISFY THE ADEQUACY CRITERIA [FIGURE 3-6]



3.2. Economic viability assessment

Based on the 'GAP volume' identified for each time horizon, an iterative process is performed in order to identify the 'in the market' economically viable capacity (existing or new) without intervention. This process is described in Section 3.2.1 The indicators used to determine the economic viability are described in Section 3.2.2.

3.2.1. Process

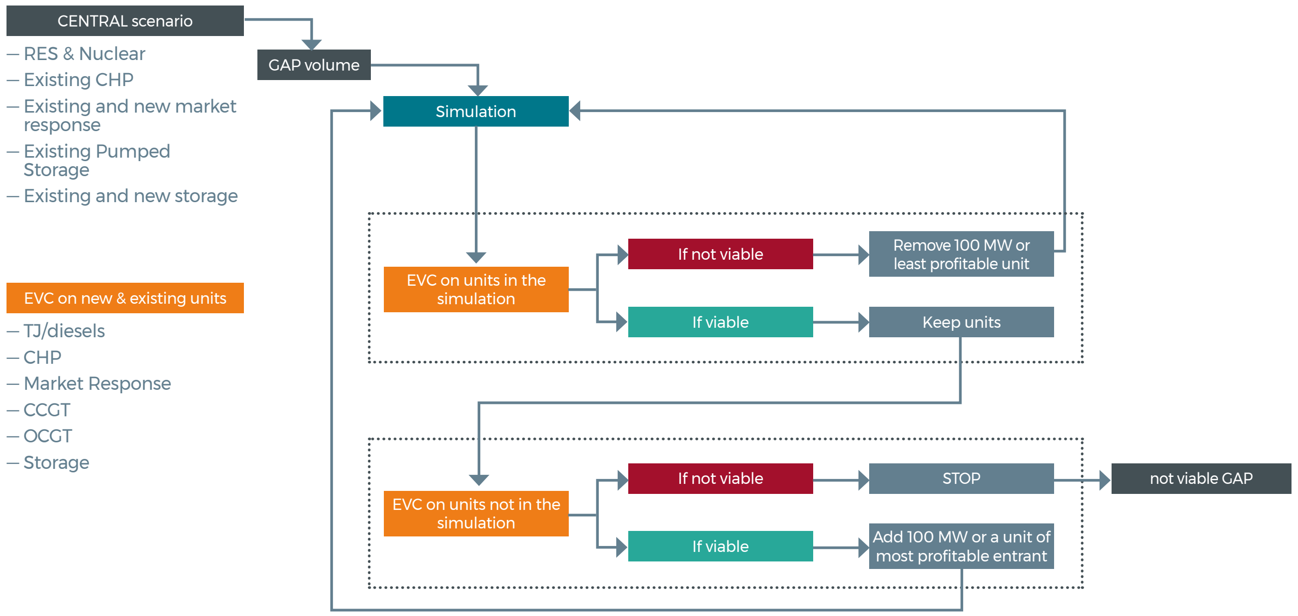
For each time horizon, an iterative process is applied to derive the technology and associated capacity that is economically viable without intervention to fill the 'GAP volume'. This process is initiated by performing a first simulation taking into account the generation, storage facilities and market response as defined in Chapter 2 for the 'CENTRAL' scenario, i.e.:

- Renewable energy sources (onshore/offshore wind, solar and biomass);
- Nuclear capacity (as defined in the law);
- Existing CHP capacity;
- Existing and new market response (based on 'Energy Pact' figures);
- Existing pumped-storage (including the increase of 7.5% of the reservoir and capacity for Coo);
- Existing and new storage facilities (small and large batteries, V2G) (based on the 'Energy Pact' figures).

On this basis, the economic viability check is performed on all the following technologies (for existing and new capacity):

- turbojets/diesels/gas engines;
- CHP;
- market response;
- CCGT/OCGT;
- storage.

ITERATIVE PROCESS FOLLOWED FOR THE ECONOMIC VIABILITY CHECK [FIGURE 3-7]



The process can be summarised as follows (see Figure 3-7):

1 **STEP 0:** An initial simulation is set up taking into account the generation and storage facilities, imports and market response as defined in the 'CENTRAL' scenario (see Chapter 2);

2 **STEP 1:** A market simulation is performed with the given assumptions;

3 **STEP 2:** An economic viability check is conducted on all units taken into account in the simulation in STEP 1:
- If a certain capacity is **not viable**, the least profitable capacity is removed by a step of 100 MW or by the size of the given unit (if its size is above 100 MW). A simulation is performed again (STEP 1) ;
- If all capacity is **viable**, the capacity is kept and STEP 3 is initiated.

4 **STEP 3:** An economic viability check is performed on capacity not included in the simulation of STEP 1. This is performed on any new or existing capacities:
- If **no viable capacity** is found, the process is stopped and the remaining 'not viable GAP' is derived;
- If a **viable capacity** is identified, new capacity by steps of 100 MW is added to the simulation by choosing the most profitable technology (in the case of existing capacity, the corresponding unit size is applied). The process restarts as from STEP 1.

The remaining 'not viable GAP' resulting from this process is the capacity needed in order to respect the adequacy criteria for Belgium, but which won't be realised by the market without changing the current market design (i.e. 'not viable GAP').

As described in Figure 3-7, the economic viability check is stopped when no viable technologies (existing or new) are identified. **The equilibrium found is fragile as adding capacity to the market (without any intervention implying extra support) in order to fulfil adequacy requirements would make part of the capacity in the market not viable anymore.**

It is therefore important to notice that the viability check outcome might result in situations where the market is not adequate (the 'in the market' LOLE is above the legal criteria). In this case, additional capacity is needed 'out of market' to meet the adequacy requirements.

The parameters used for the economic viability check are described in Section 2.9.

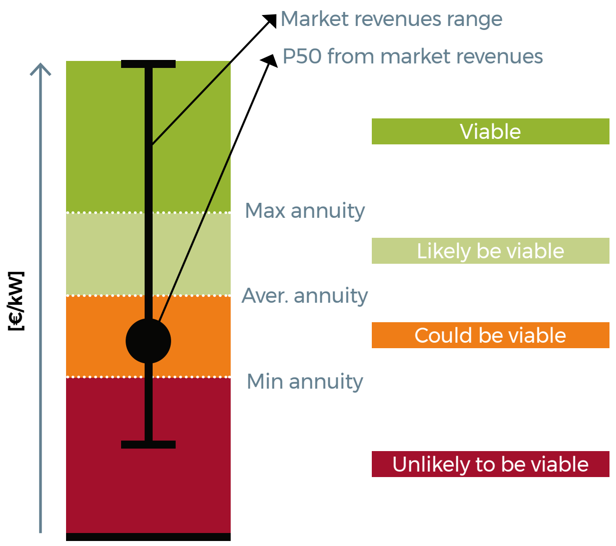
3.2.2. Viability check

The economic viability assessment for a given technology is based on the inframarginal rent that it gets from the 'Energy-Only Market' (EOM). Ancillary services and additional revenues other than those from the EOM are not considered in those figures. It is however assumed that such revenues would not overthrow the conclusions (cf. Section 2.9.7).

The inframarginal rent for a given technology is assessed against two indicators:
- **FOM** (Fixed Operation & Maintenance Costs) if no new investment/refurbishment is needed;
- **FOM + investment annuity** for a unit/technology if new investments or refurbishments are needed (for a given Weighted Average Cost of Capital (WACC)).

The 'percentile 50' (1 out of 2) of the inframarginal rent (across all simulated 'Monte Carlo years') distribution will always be assessed against the minimum annuity obtained from the CAPEX and FOM ranges (see Section 2.9.4 for more information).

DEFINITION OF VIABILITY BY COMPARING ENERGY MARKET REVENUES AND ANNUITIES [FIGURE 3-8]



The percentile 50th (P50) will always be assessed against the minimum annuity

Is an existing unit economically viable?

An existing unit in the market is economically viable (assuming no cost related to past investments as those are considered sunk costs) if the inframarginal rent can cover its Fixed Operation and Maintenance (FOM) costs. The FOM represents the costs to maintain the installation, independent of the number of running hours (excluding investment costs). The input data used in this study for the FOM for each technology is summarised in Section 2.9.4.1.

Is a new investment economically viable?

If the unit's inframarginal rent can cover the FOM and investment costs, a new unit is considered economically viable. In other words, as the investor may contemplate the prospect of having, over the lifetime of the investment, their investment costs and FOM covered by inframarginal rent generated in the market, they will be willing to make the investment.

Given that this study only looks at three specific years, the investment costs will be expressed in annuities taking into account the 'Weighted Average Costs of Capital (WACC)', the economic lifetime and the CAPEX. The input data used in this study for annuity computation are summarised in Section 2.9.4.

Based on this indicator, if the unit's inframarginal rents are lower than the annuity and FOM for a given year, a new unit has a low probability of being built. Note that investment decisions are based on future assumptions over the entire expected lifetime of a unit. This study has only analysed three specific years and a range of climate years, which gives only an indication.

Note also that other factors such as risk tolerance (e.g. is P50 or another level considered?, is a minimum annuity or a higher level considered?) are also crucial for investment decisions. In the end it obviously remains the decision of the investor, which may be based on a variety of aspects that are taken into account. This analysis includes those elements that can be calculated and are in any case aspects that serve as input for each investment decision.

Finally, it is important to mention that the assumptions used to perform the economic viability check in this study are based on public information (investment costs, FOM) and market or expected market prices (CO_2 and fuel costs). If an investor has access to lower costs/prices than the market or to privileged contracts for any reason, the conclusions might differ. This could be the case in the recent announcement that investments would be made in new gas-fired units in Belgium, but this cannot be verified by Elia and neither be considered as a 'standard' set of assumptions.

L'Echo - 15/05/2019 – (Own translation from French)

Qataris ready to invest in Belgian gas plants [...]

"The difference is that our business plan does not take into account the CRM, the capacity remuneration mechanism that Belgium is about to put in place", reacts Marc Segers. *"Of course, if we can benefit from it, we we will be pleased, but our project is holding up thanks to guaranteed gas prices over the long run."* Clearly, liquefied natural gas (LNG) from Qatar.[ECH-1]

BOX 10 : REVENUES AND RUNNING HOURS

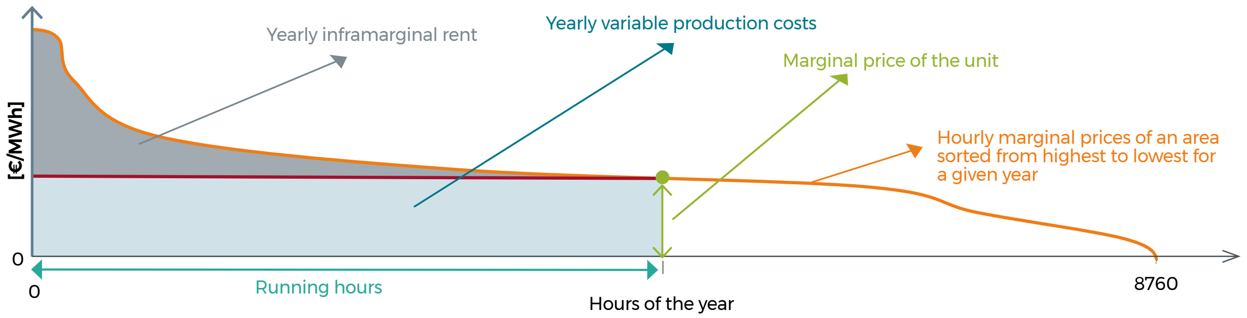
The profitability and running hours for each technology are calculated based on the following model outputs:

• The hourly dispatch for each unit;

• The hourly marginal price.

Figure 3-9 illustrates the different concepts used in this section to evaluate the profitability of a technology. This figure is an example for a theoretical unit assuming no outages nor other dispatch constraints.

EXAMPLE: INFRAMARGINAL RENT, PRODUCTION COSTS, MARGINAL PRICE AND RUNNING HOURS FOR A GIVEN AREA [FIGURE 3-9]



Running hours calculation based on the marginal cost of generation

The running hours of each unit are a direct output of the model based on its marginal costs. The marginal cost is equal to the variable cost of production of each unit and is the sum of three elements:

1 Fuel costs;
2 Direct emissions' costs;
3 Variable Operation and Maintenance costs (VOM).

The marginal cost (short-term) of a production unit is defined as being the cost to produce an additional amount of energy (1 MWh) and is expressed in €/MWh produced.

The unit will run only when the market price is above this marginal cost.

Unit revenues and inframarginal rent

The revenues of each capacity are calculated based on the 'inframarginal rent'. The inframarginal rent for a given capacity is defined as the difference between the revenues of the unit in the energy market (market price multiplied by the generated energy) and the variable production costs defined above. For a given hour, the inframarginal rent is defined as follows:

Inframarginal rent $(h)_{unit\ A}$ =
Revenues $(h)_{unit\ A}$ - *Variable production cost* $(h)_{unit\ A}$
= [*Market price(h)* * *Energy produced* $(h)_{unit\ A}$] - [*Fuel cost* $_{unit\ A}$ + CO_2 *emission cost* $_{unit\ A}$ + *VOM*]

Note that this inframarginal rent is calculated in this study on a 100% available capacity basis without energy constraints.

3.3. Welfare calculations

In order to assess the societal benefit of a given investment or to evaluate different capacity mixes, a Cost-Benefit Analysis is used which follows the methodology as described in the Guideline from the European Commission for Cost-Benefit Analysis of Investment projects for the Cohesion [EUC-6]. This assessment is based on three factors:

1 Annuity: represents the annual payment for an investment or a capacity mix taking into account Weighted Average Cost of Capital (WACC) and a given economic lifetime;
2 Fixed Operation and Maintenance (FOM) costs: the yearly fixed costs of the given investment or capacity mix;
3 Market welfare: expresses the gain/loss for the consumer, producer and congestion rent for Belgium as a whole.

The sum of those 3 factors called '**net market welfare**' represents the gain in market welfare brought by the investment, taking into account the yearly costs of the investment for the given area:

Net welfare = Market welfare - Fixed O&M - Annuity

In order to determine the market welfare generated by the investment or to compare different capacity mixes, two simulations need (at least) to be performed as the welfare is always a calculated as a difference between two settings.

The market welfare as calculated is an indicator to determine the additional gain/loss induced by an investment or different capacity mix for the consumers, producers and the congestion rents.

The Consumer surplus

The consumer surplus is defined as the difference between the maximum price which the consumer is willing to pay (in this case the price cap of the model) and the actual price they pay.

The Producer surplus

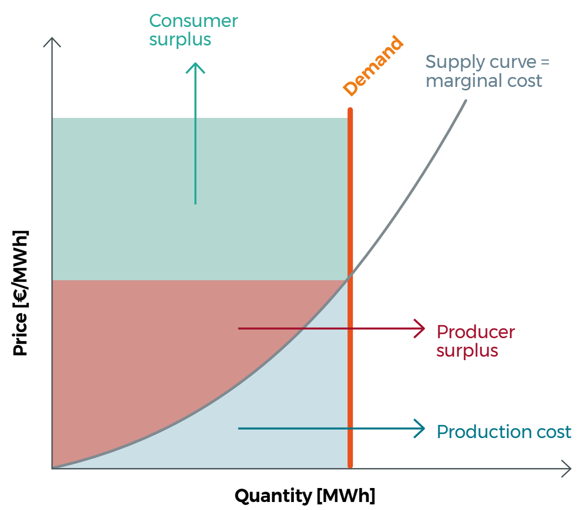
The producer surplus is defined as the market price, multiplied by the quantity of energy produced minus the total variable cost of production.

The Congestion rents

The global congestion rent is equal to the sum over all areas' balances multiplied by the market price of the area, where imports/exports reflect a positive/negative balance.

The market welfare will always be assessed against a chosen reference case. Only relative deltas on the above-mentioned indicators are provided.

CONSUMER AND PRODUCER SURPLUS [FIGURE 3-10]



3.4. Flexibility

3.4.1. Introduction

3.4.1.1. DEFINITION OF POWER SYSTEM FLEXIBILITY

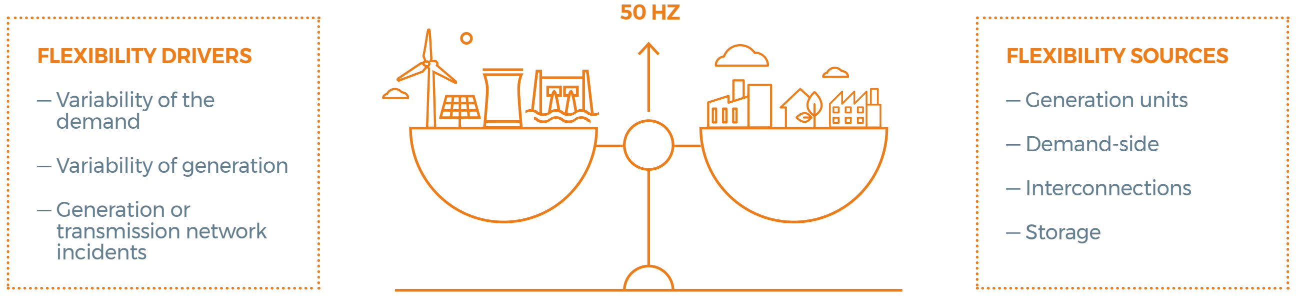
Although many definitions exist in the literature, the flexibility of a power system is generally defined as: 'the extent to which a power system can modify electricity production or consumption in response to variability, expected or otherwise'. This is also the definition used by the International Energy Agency [IEA-3]. As shown in Figure 3-11, power systems and markets need flexibility to cope with three types of uncertainty (or flexibility drivers):

1 **the variability and uncertainty of the demand:** it is not possible to know beforehand the exact electricity demand as it depends on external variables such as consumer preferences and weather conditions. Nevertheless, short-term demand forecast tools are used by market parties and system operators to predict the demand on a week-ahead, day-ahead and intra-day basis to schedule their portfolio and manage their operations.

2 **the variability and uncertainty of renewable and distributed generation:** renewable generation such as wind and solar power is particularly characterised by uncertainty as it is subject to variable and uncertain weather conditions. This is also the case for some distributed generation sources, facing variable generation profiles such as Combined Heat and Power or run-of-river hydro following consumer preferences or weather conditions. Dedicated forecast tools are used by market parties and system operators to predict variations as accurately as possible on a day-ahead and intra-day basis in order to schedule their portfolio and manage their operations.

3 **unexpected outages of generation units or transmission assets:** forced outages are an inherent characteristic of generation and transmission systems and are unpredictable. They result in a sudden loss (or excess) of power. Forced outages in decentralised generation sources are generally less of an issue due to their dispersed nature, and are typically included in the variable or distributed generation profiles.

FLEXIBILITY DRIVERS AND SOURCES FOR FLEXIBILITY [FIGURE 3-11]



In order to maintain the system in balance, an important prerequisite for system security, these expected and unexpected variations of demand and generation must be covered at all times with flexible resources, referred to as the flexibility means of the system. These are delivered by technologies, which are controllable, i.e. can alter their generation or demand upon request in a relatively short time frame. These capabilities can be provided by the following technologies:

1 **generation units:** all generation units are flexible to a certain extent, but not all of them are managed today in a flexible way. It is assumed that most conventional thermal units can modify their output in an acceptable time frame. An exception is the Belgian nuclear power plants which are typically operated as base load units (although some temporary output reductions are proven to be possible under certain conditions). Additionally, non-thermal generation capacity can have flexible capabilities such as renewable generation, which can, when running, regulate its output downward (upward regulation is considered as costly as this would require a capacity reservation and the availability of wind). Combined-Heat and Power (CHP) can have constraints as they depend on heat demand;

2 **demand-side:** demand-side management can provide flexibility by means of modifying its demand following a reaction on explicit signals, or implicitly by reacting on price signals. In this study, these are referred to as consumption shifting or demand response processes respectively. Note that demand-side management is generally activated to facilitate demand reductions (a demand increase would imply using more energy as required which is generally related to electricity storage processes);

3 **electricity storage:** these technologies are generally very flexible and are characterised by an 'energy' reservoir with which they can store electricity via another energy carrier, and convert this back to electricity upon request. Consequently, these technologies face limitations concerning this energy reservoir. Several storage technologies exist, but for the moment the most relevant for Belgium are the large pumped-storage units and battery facilities;

4 **interconnections** which can import (or export) flexibility from / to other regions by means of cross-border forward, intra-day/day-ahead or balancing markets. Today, the development of a European balancing market is an ongoing project that will facilitate the further development of close-to-real-time flexibility exchanges. Note that the availability of this capacity depends on the availability of transmission capacity (besides availability of the generation, storage or demand response in other countries).

Ensuring that the system flexibility needs are covered is as important as making sure that the installed generation capacity is able to cover the peak demand. Shortages in flexibility can equally result in emergency measures to avoid frequency deviations and preventive or real-time generation curtailment or load shedding. Therefore, the flexibility study investigates if the future power system has the sufficient technical capabilities and characteristics to deal with demand and generation variations.

3.4.1.2. FLEXIBILITY IN THE ELECTRICITY MARKET

The diagram in Figure 3-12 illustrates the main mechanisms of the operation of the current electricity market. Market players are responsible for balancing injections and off-take in their portfolio. They must therefore nominate an energy portfolio one day in advance (day-ahead) that guarantees an equilibrium and by moving further closer to real-time resolve any detected imbalance in their portfolio. It is therefore necessary for the market to have sufficient flexibility, both intra-day and in real-time, to compensate for forecast errors on generation, in particular in regards to renewable energy sources and off-take. In addition, the flexibility available in the system must always allow for the loss of power plants (an unavailability known to occur on day-ahead as well as an unforeseen unavailability after day-ahead).

The role of the system operator in managing flexibility is complementary to the market because it neutralises the residual imbalance between injection and offtake that is not covered by market players. By means of the imbalance settlement tariff, it incentivises the market to cover their balancing responsibility as much as possible. This imbalance tariff is driven by the cost of activating balancing energy to resolve the residual system imbalance, as well in both an upward (to deal with energy shortage) and downward (to deal with energy surplus) direction. Due to this 'reactive' balancing mechanism, a large part of the required flexibility is delivered by intra-day markets and real-time actions and not by Elia.

The TSO uses reserve capacity to cover the residual system imbalance as represented in Figure 3-13. If an imbalance in the system occurs, this results in an increase or decrease in the system frequency. Because the control zones of the ENTSO-E network - also called the Load Frequency Control (LFC) blocks of which the ELIA LFC block represents the Belgian geographical area - are connected, a frequency disturbance impacts the entire synchronous zone.

The Frequency Containment Reserve (FCR) must restore the balance between the power provided and the power supplied. It is used to stabilise the frequency at a level greater or smaller than the initial frequency, rather than balancing the ELIA LFC block. BOX 11 explains how the required FCR volume is dimensioned by ENTSO-E at European level and allocated to the relevant LFC blocks.

TIME HORIZONS FOR FLEXIBILITY [FIGURE 3-12]

MARKET PARTIES

DAY-AHEAD MARKET
- Each market party nominates its portfolio per hour in balance based on predictions
- This balance is achieved by means of using various flexibility sources, by means of contracts or own flexibility means

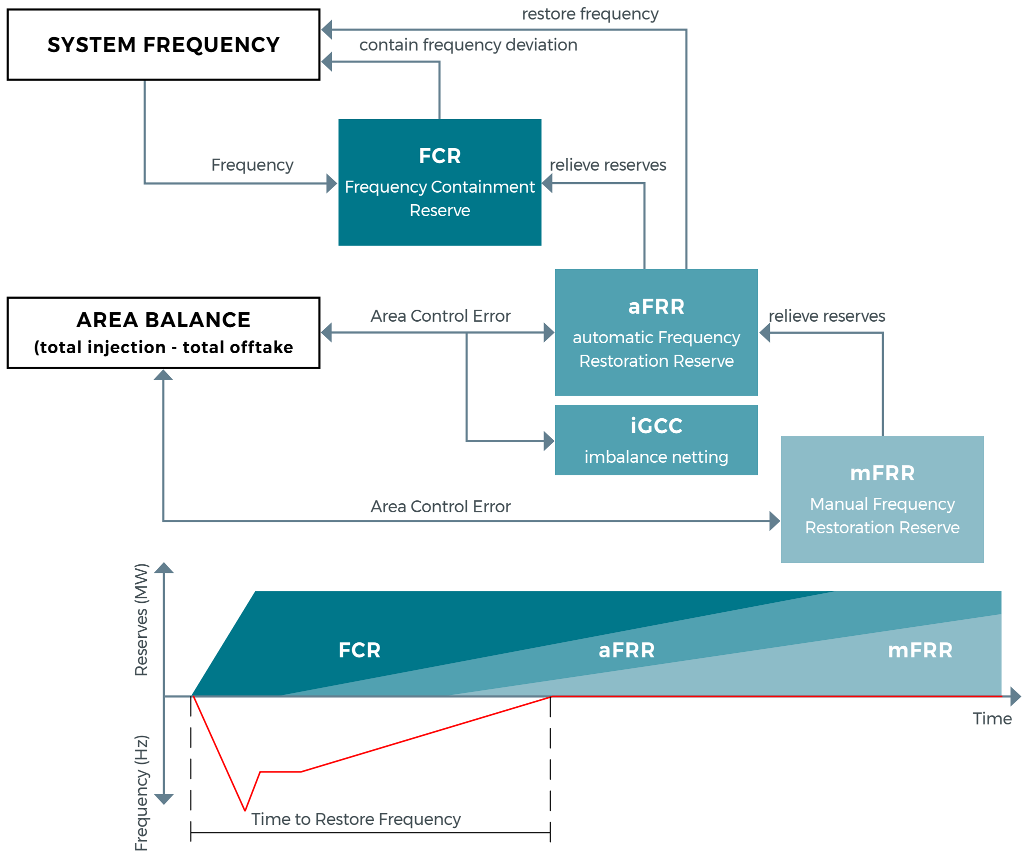
INTRA-DAY MARKET
- Restoring the balance based on new forecasts :
  - by means of intra-day market (until 1 to 2 hours before real-time), or
  - through own flexibility means

INTRA-DAY TO REAL-TIME
- Imbalance settlement tariff of Elia gives incentive to restore balance
- Additional deviations (forced outage, wind power variations) can be dealt with bilaterally or by means of own flexibility means

ELIA

REAL-TIME BALANCING
- Elia manages the residual aggregated system imbalance
  - with imbalance netting with other regions,
  - with ancillary services (FCR, aFRR and mFRR), or,
  - with non-contracted energy bids from market parties

ACTIVATION PROCESS OF ELIA'S RESERVE CAPACITY [FIGURE 3-13]



The Frequency Restoration Reserve (FRR) must free up the FCR of the synchronous zone to prevent network instability, or even a failure of the entire electricity system, in the event of additional system imbalances. Each control area is therefore obliged to maintain its balance which is monitored by means of quality criteria assessing the Area Control Error (ACE), i.e. the real-time deviation between measured and scheduled cross-border exchanges on a quarter-hourly (and even by minute) basis.

Unlike the FCR, the FRR ensures that the frequency in the synchronous zone is restored, and that the control zone is re-balanced. The automatic FRR (aFRR) is mainly used to compensate for short and random imbalances. The manual FRR (mFRR) serves as compensation for long, persistent and/or very extensive imbalances.

- aFRR must be activated automatically within 30 seconds and must be fully available within 7.5 minutes;
- mFRR is manually activated and must be fully available within 15 minutes.

The required capacity of FRR is determined by Elia as explained in BOX 11.

BOX 11: DIMENSIONING PROCESS OF RESERVE CAPACITY

The required FCR volume is dimensioned by ENTSO-E for the synchronous area of continental Europe. It is calculated on the largest contingency, currently the loss of 3000 MW, complemented by a probabilistic analysis. This volume is allocated to the corresponding LFC blocks according to their weight (in terms of consumption and generation) in the synchronous zone. The methodology is specified in the synchronous area operational agreement and is approved by all relevant regulators [ENT-7]. The current FCR capacity in Belgium is 80 MW.

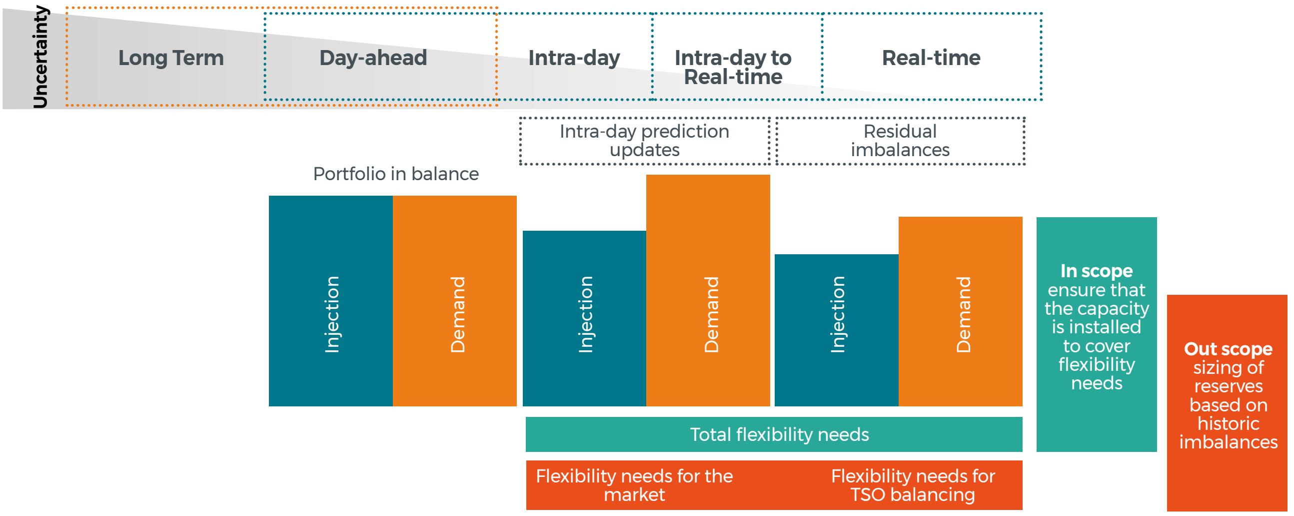
The required FRR capacity is dimensioned by Elia for its LFC block. First the needs are determined with a methodology presented in the LFC block operational agreement [ELI-19], subject to a public consultation and approved by CREG. For 2019, Elia presented an upward FRR need of 1039 MW (and aFRR needs of 145 MW). Furthermore, 'dynamic' downward FRR needs are determined each day based on a calculation of the imbalance risk. Elia also expects to implement this dynamic methodology for upward in 2020.

The volumes are thereafter allocated towards different products for balancing capacity : aFRR, mFRR standard and mFRR flex. No downward mFRR is contracted at the moment. This allocation takes into account the availability of shared reserves with other TSOs and non-contracted energy bids.

3.4.1.3. SCOPE AND OBJECTIVE OF THE FLEXIBILITY STUDY

As represented in Figure 3-14, this flexibility analysis focuses on the flexibility required between day-ahead and real-time to ensure the balance in the Belgian LFC block. **The scope of the flexibility analysis is therefore on the capabilities which are required to cover the expected and unexpected variations of the residual load between day-ahead and real-time**. In general, long-term variations (yearly, seasonal, daily) are also referred to as flexibility, but are already covered in the adequacy assessment as these are taken into account in the simulations with several Monte Carlo years representing the day-ahead market schedules with an hourly resolution.

SCOPE OF THE ADEQUACY AND FLEXIBILITY STUDY [FIGURE 3-14]



The **residual load** is defined in this study as the electricity demand minus generation from variable renewable energy sources (wind, solar and run of river hydro-electric plants following weather profiles) and, other 'must run' decentral generation (combined heat and power and waste incineration following operational constraints such as heat profiles). Imports and exports via interconnections are not specifically taken into account.

Until today, intra-day to real-time variations of the residual load have never been explicitly investigated by Elia. Although the previous adequacy and flexibility study [ELI-2] highlighted a few characteristics of residual load variations, it mainly focussed on estimating the required balancing capacity, and did not investigate in detail whether the system was able to cover :

1. unexpected variations following forecast errors and forced outages in real-time;
2. forecast updates between day-ahead and real-time,
3. 15 minute variations in real-time.

By focusing only on the future availability of reserve capacity, this would implicitly assume that part of the flexibility to be delivered by the market is by default available in the system. Obviously, this is not necessarily the case. This may result in an underestimation of the impact of the required capacity and flexibility of the system. Secondly, it is extremely difficult to estimate the future share of the flexibility needs covered by the TSO as this depends on the future performance of the market.

The proposed methodology in this study therefore determines the total flexibility needs which are required between day-ahead and real-time. The methodology makes an abstraction whether it is the market, or the TSO which has to cover the required flexibility. Closer to real-time, this exercise is conducted by means of Elia's dimensioning methodology for FRR, approved by the regulator after a public consultation. This methodology is based on the residual imbalance to be covered by the TSO and currently evolving towards a method based on intelligent statistical algorithms which relate the required reserve capacity to the system imbalance risk based on expected system conditions.

3.4.1.4. BEST PRACTICES

Best practices based on studies published by TSOs, utilities, energy agencies, research institutes and academic papers reveal few contributions which facilitate a direct implementation of the methodology in Belgium. Most studies focus on the integration of new technologies such as batteries or demand-side management, or on modelling the ideal generation mix for a region in view of increasing shares of renewable integration. Only a few TSOs have published long-term flexibility studies.

However, the general impression is that most TSOs have only recently started looking at the issue in view of increasing renewable generation. Recent studies in Europe and around the world confirm that flexibility is becoming a crucial point for system adequacy. ENTSO-E aims to provide further insights into flexibility in the upcoming MAF reports [ENT-1]. At this stage, three approaches are specified:

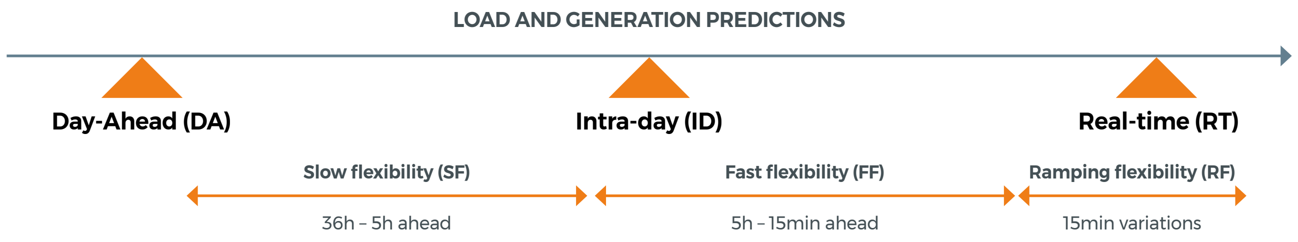
1. **Quick estimates** determine some key figures and metrics concerning the flexibility required and the flexibility installed in a system. This may concern an overview of the installed capacity of controllable thermal plants, pumped-storage, demand response and interconnectors, or an analysis of the largest possible power variation in the system. Such approaches, certainly in combination with visualisation tools, allow and provide a comprehensive overview and first understanding of future issues, and allow benchmarking with other regions. However, they do not accurately specify future flexibility needs, and test their availability in the system. A few examples can be found in [NRE-1].
2. **Residual load analyses** make it possible to assess flexibility needs without a dispatch model, but based on historical variations and forecast errors of demand and variable renewable generation. This is based on a time series analysis of historical data resulting in demanding data requirements, i.e. the availability of at least one year of historical observations and predictions. Maximum variations and forecast errors can be used as metrics allow them to have a cross-check with available system capabilities. Examples can be found with the Californian [CAI-1] and Finnish TSO [POY-1]
3. **Modelling flexibility in system models** allow flexibility to be specified in unit commitment and economic dispatch models and are also used for adequacy studies such as the one used by Elia. This integrated approach is obviously the most complex in terms of mathematical efforts (e.g. impact on computation time) and requires the introduction of new criteria to represent the lack of flexibility (e.g. ramping margins, insufficient ramping resource expectations). The results depend strongly on the level of detail on which the flexibility needs are modelled (e.g. resolution, time horizon). An example of such an approach can be found with the Greek TSO [RAE-1].

The methodology used by Elia combines elements of the above-mentioned categories: an assessment of the flexibility needs based on historical data, and an assessment of the available flexibility based on the outputs of its adequacy simulations. With this approach, Elia presents a new methodology based on current best practices. The methodology also allows further improvements and evolutions in the future, based on feedback from stakeholders and experiences following implementation.

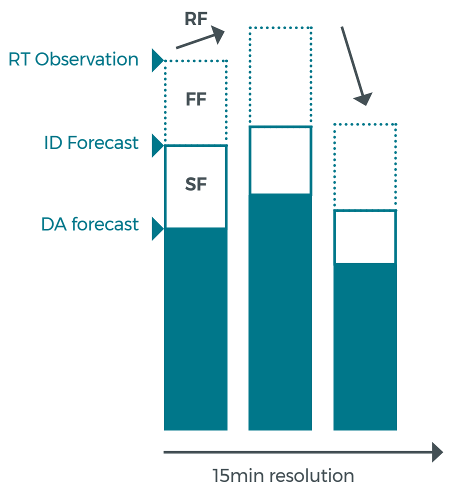
3.4.2. Methodology to determine the flexibility needs

The flexibility needs assessment is based on a categorisation of three types of flexibility (Figure 3-15) derived from the time that new information is received by the market players. This may concern forecast updates, or information concerning the unexpected unavailability of a power plant.

TYPES OF FLEXIBILITY [FIGURE 3-15]



Type of Flexibility	SF Slow Flex	FF Fast Flex	RF Ramping Flex
Definition	Capacity which can be started or shut down in intra-day (until a few hours ahead)	Capacity which can be regulated up- or downward close-to-real-time	Capacity which can be regulated up- or downward in a timeframe of minutes
Objective	Deals with intra-day prediction updates of residual load and update on forced outages	Deal with unexpected variations of residual load and forced outages	Deal with fast variations of residual load
Indicator	Future residual load forecast errors between day-ahead and intra-day	Future residual load forecast errors between intra-day and real-time	Variations residual load forecast errors between intra-day and real-time



- **Slow flexibility** represents the ability to deal with expected deviations of demand and generation following the intra-day forecast update. It concerns information received between the day-ahead market (up to 36 hours before real-time) and the intra-day forecast received several hours before real-time, depending on the forecast service. Additionally, this flexibility deals with outages of power plants or transmission assets which are announced several hours before real-time (or still not resolved after several hours). This flexibility can be provided with most of the installed capacity as there are several hours to change the output of a generation, storage or demand unit and even start or stop a power plant.
- **Fast flexibility** represents the ability to deal with unexpected power deviations in real-time, or deviations for which information is received between the last intra-day forecast and real-time. It concerns information received between several hours up to a few minutes before real-time, depending on the forecast service. Additionally, this flexibility type needs to deal with forced outages up to several hours until the providers of slow flexibility can take over. Fast flexibility can be provided with generation units which are already dispatched and able to realise a modification in their output programme within a few minutes, or units which have start or stop time in a few minutes, as well as storage units (pumped-hydro and batteries) and types of demand-side management which are considered very flexible.
- **Ramping flexibility** represents the ability to deal with the real-time variations of the forecast error and in particular the forecast errors of the last intra-day forecast before real-time. It can be expressed as capacity required up to 15 minutes, or per minute (MW/min). This type of flexibility does not cover forced outages which are assumed to be covered by FCR, and relieved by fast and slow flexibility. Ramping flexibility is to be covered by assets which can follow forecast error variations on a minute-basis and therefore only those units which are already dispatched, as well as some battery storage and demand-side management which are considered very flexible.

The split between slow and fast flexibility is set at 5 hours before real-time. This is determined based on :

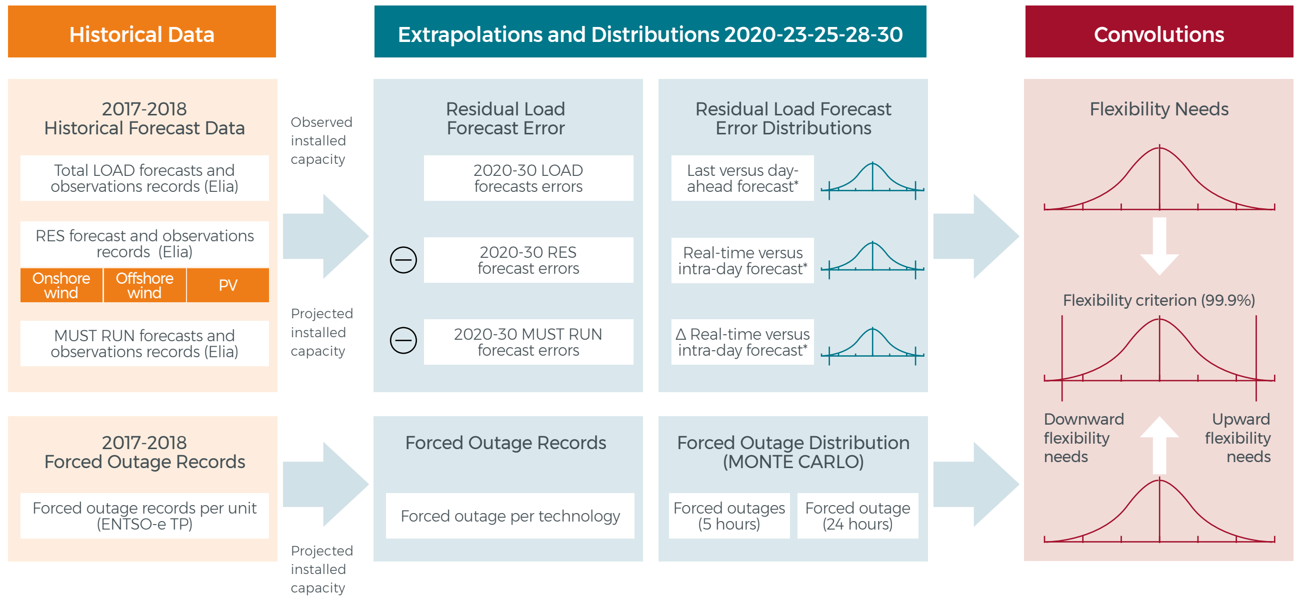
- the timing of the intra-day forecast update. Different intra-day updates are available at predefined moments during the day depending on the forecast service. As shown in Figure 3-15, the most recent intra-day forecast currently used by Elia is taken as a reference value to make the split between fast and slow flexibility. Currently, this forecast update arrives between 15 minutes and 5 hours before real-time depending on the forecast service.
- the technical limitations concerning start-up time of a unit. In general, most units can start in a time frame of several hours allowing them to deliver slow flexibility. However, some units can start in a time frame of a few minutes. These can therefore deliver fast flexibility even when not being dispatched. As shown in Figure 3-15, the split between slow and fast flexibility is set at 5 hours before real-time, which relates to the start-up time of an existing CCGT unit.

The flexibility needs for each type of flexibility is determined in three steps by:

1. determining the probability distribution of the forecast errors of the demand, renewable and distributed generation, aggregated as the residual total load forecast error ;
2. determining the probability distribution of the forced outage of generation units and certain transmission assets and ;
3. determining the flexibility needs based on a convolution of both probability distribution curves.

This analysis is represented in Figure 3-16 which is conducted for each future year 2020, 2023, 2025, 2028 and 2030 based on an extrapolation of the relevant time series by means of the demand and generation capacity projections towards that year.

SCHEMATIC METHODOLOGY OVERVIEW [FIGURE 3-16]



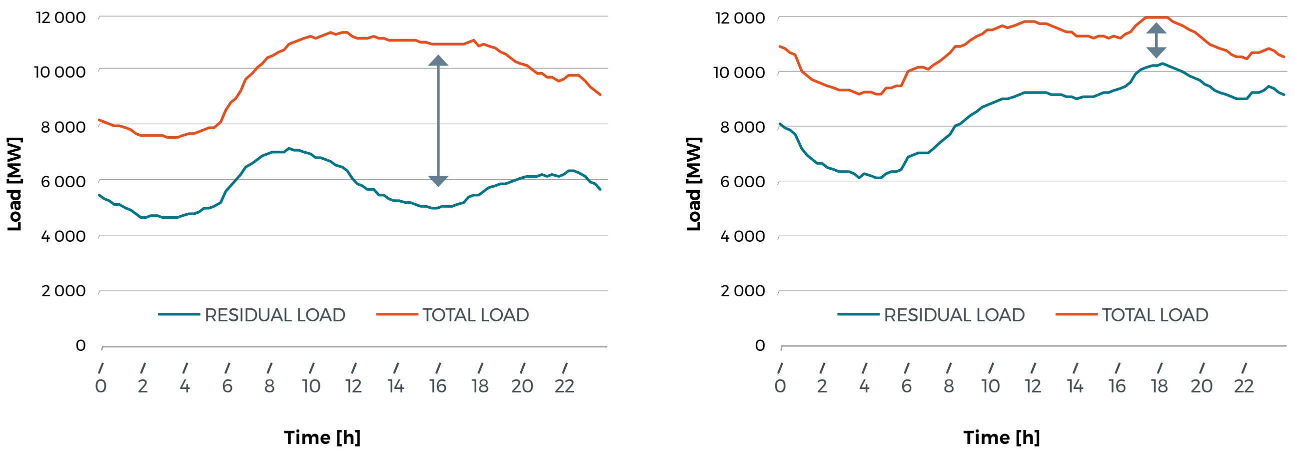
3.4.2.1. STEP 1: RESIDUAL LOAD FORECAST ERROR

The residual load is defined in Section 3.4.1.3 and represents both variability due to total load and due to generation. This corresponds to the part of the load (positive or negative) to be covered by different means of flexibility, in particular the flexible generation units, purchase and sale of electricity through interconnections, demand management and storage. The calculation of the residual load is based on the assumption that there is energy produced by renewables (wind and solar) or that the demand-side is not optimised during the day-ahead time frame. However, it is important to note that production from variable renewable energy sources, as well as the demand-side in itself has a potential to contribute to providing flexibility. This is taken into account as well during the assessment of the available flexibility means.

Figure 3-17 illustrates the spread between the residual load and the total load for a day with high renewable generation, and a day with low renewable generation:

- The **total load** includes a time series based on all the electrical loads on the Elia grid and in all underlying distribution grids (and also includes electrical losses). It is estimated based on a combination of measurements and scaled-up values of injections from production units, including production in distribution networks, to which imports are added. Subsequently, export and energy used for energy storage are deducted.
- The **residual load** subtracts the renewable and decentral 'must run' generation from the total load. These profiles include a separate time series per technology for onshore wind, offshore wind, solar photovoltaics and decentral generation. The latter aggregates the production of different decentral production sources including CHP, Run-of-River Hydro and Waste Incineration.

ILLUSTRATION OF THE DAY-AHEAD PREDICTION OF TOTAL LOAD AND RESIDUAL LOAD FOR A DAY IN JUNE 2025 (LEFT) AND JANUARY 2025 (RIGHT) [FIGURE 3-17]

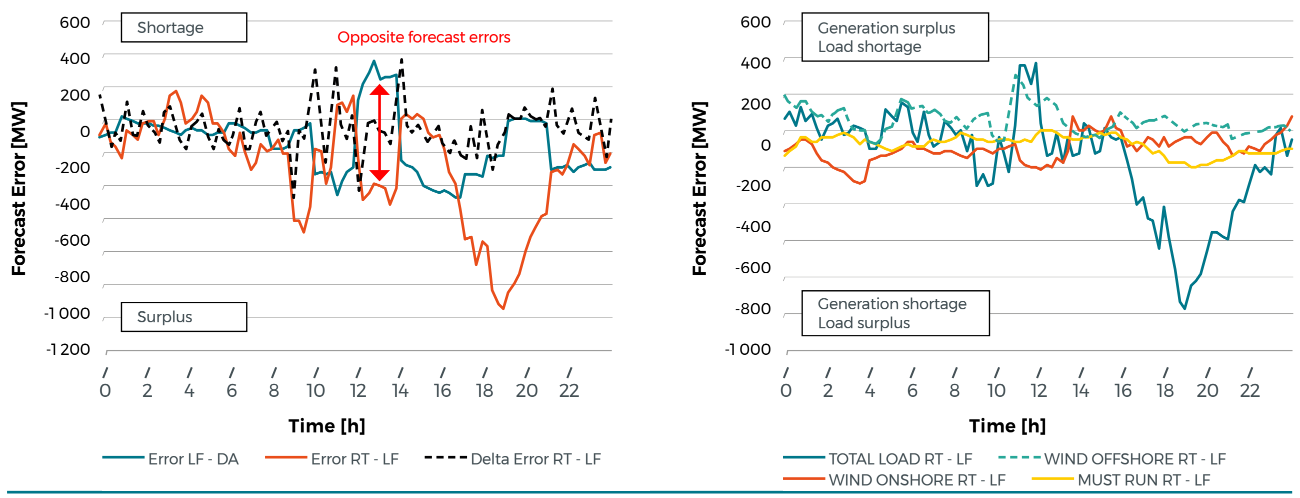


A database is constructed representing a representative time series of historical real-time production / load estimations, intra-day forecasts and day-ahead forecasts for the total load, wind onshore, wind offshore, photovoltaics and must run generation. The databases are based on data generated by the forecast tools Elia makes available for the market and is further discussed in Section 2.8.1. By means of this data, three new time series are created per technology :

- **Error Last versus Day-Ahead forecast (Error LF – DA)**, representing the historical forecast error [MW] between the day-ahead (DA) and the last forecast (LF);
- **Error Real-time versus Last forecast (Error RT – LF)**, representing the historical forecast error [MW] between the last forecast and the real-time (RT) estimations (or observations),
- **Δ (delta) Error RT-LF**, representing the historical forecast error variations [MW] of the Error RT – LF between two subsequent quarter-hours.

Figure 3-18 illustrates these profiles for a day in June. It also shows that the intra-day forecast does not always result in a better forecast (although it does on average) which may result in opposite forecast errors for the day-ahead and intra-day. Additionally, it highlights how sometimes, the forecast errors of different technologies smoothen each other out, and reinforce each other during other periods.

ILLUSTRATION OF RESIDUAL LOAD FORECAST ERRORS AND VARIATIONS (LEFT) AND THE ERROR RT – LF PER FORECAST SERVICE (RIGHT) BASED ON A DAY IN JUNE 2018 [FIGURE 3-18]



All time series values are expressed as a percentage of the monitored capacity (the demand is expressed in terms of the average demand, the renewables and must run generation in terms of installed capacity). This enables Elia to extrapolate the time series towards projected values for the period 2020 to 2030. This extrapolation is conducted by means of the installed capacity and demand projections towards 2030, while taking a forecast improvement factor into account (presented in Section 2.8.1).

Finally, the forecast errors are aggregated over the different drivers resulting in three aggregated time series per time horizon. These are used to build the three probability distributions per time horizon: 2020, 2023, 2025, 2028 and 2030 and for the Error LF - DA, Error RT – LF and the Delta Error RT – LF used for the slow, fast and ramping flexibility respectively.

3.4.2.2. STEP 2: FORCED OUTAGES

The probability distribution curve of the forced outages is created for fast and slow flexibility needs. The probability distribution is based on a time series generated with a Monte Carlo simulation taking into account the generation fleet and relevant HVDC interconnectors for the year for which the simulation is conducted with the following parameters:

- The **maximum generation capacity or transmission capacity** of relevant generating units and interconnectors: the maximum capacity is aligned with the adequacy study assumptions. Note that only NEMO-Link is considered relevant as other interconnector outages result in an import or export via other electrical paths (which is foreseen when calculating operational margins). This is not the case with NEMO-Link being the only electrical connection between Belgium and the United Kingdom.
- **The outage probability and duration**: these parameters are based on an historical analysis of forced outages of different generation types (or HVDC interconnectors). Note that the duration is capped towards 5 hours and 24 hours for fast and slow flexibility, respectively. This is generally below the observed duration but the slow flexibility is assumed to relieve the fast flexibility after 5 hours (when for instance new generation units can be started), and the slow flexibility is relieved by the day-ahead market after 12 - 36 hours.

This also results in three probability distributions for 2020, 2023, 2025, 2028 and 2030, taking into account evolutions in the generation fleet (including the nuclear phase out and the entry of new capacity).

3.4.2.3. STEP 3: CONVOLUTIONS AND DETERMINATION OF THE FLEXIBILITY NEEDS

In this final step, for each time horizon (2020, 2023, 2025, 2028 and 2030), the probability distribution curves representing the forced outage risk and the prediction risk are convoluted. This is done for each type of flexibility needs:

- **The slow flexibility** : Prob(Error LF – DA) + Prob($FO_{24hours}$)
- **The fast flexibility** : Prob(Error RT – LF) + Prob(FO_{5hours})
- **The ramping flexibility** : Prob($\Delta_{t,t-1}$[Error RT – LF])

This results in three new probability distributions, per time horizon for which a reliability level determines the flexibility needs. The 0.1% and 99.9% percentile determines the down- and upward flexibility needs. The flexibility needs for every distribution is determined as the percentile of each distribution. This results in flexibility needs in MW for up- and downward for the period DA/LF and LF/RT but also in flexibility needs in MW for the delta error LF/RT, which can in turn be expressed as MW/min by dividing the result with 15 minutes.

A criteria of 99.9% is selected as the trade-off between accuracy and reliability as there is no legal framework for covering the flexibility needs. Choosing the LOLE criteria for both flexibility and adequacy models may “push” the overall reliability criteria below the legal criterion of 3 hours per year (or 20 hours in case of the LOLE95). In view of this, a 100% target reliability should be strived for. However, setting the percentile too high could make the results too sensitive for extreme events and data problems specific to the historical years considered.

Note that the flexibility needs are considered fixed. In reality flexibility needs may vary depending on hour of the day, season and may even be related to other system conditions. This is not investigated in this study.

3.4.2.4. RELATION WITH ELIA’S BALANCING RESERVES

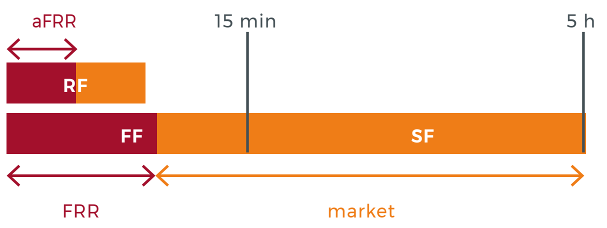
While the study assesses the total flexibility needed in the system, it does not further investigate which share needs to be covered by the market players, and which share by the TSO through reserve capacity. The main objective for the TSO is to only contract what is needed to ensure system security in line with the European network guidelines while incentivising the market players to balance their portfolios as much as possible. The split is therefore investigated closer to real-time, until 2019 year-ahead, Elia is planning to go for a dynamic dimensioning method with day-ahead dimensioning after 2019.

As represented in Figure 3-19, reserve capacity is thus not determined anymore but can be seen as a subset of the fast and ramping flexibility. When establishing a link between the reserve capacity types and the flexibility types, one can say that the fast flexibility will contain the future FRR (aFRR + mFRR) needs, which shall be at maximum contracted power in 12.5 – 15.0 minutes. However, the ramping flexibility will contain the future aFRR which shall be able to react in 5.0 – 7.5 minutes. Slow flexibility is assumed to be covered entirely by liquid intra-day markets.

Note that the FCR falls outside of these categories and shall be seen as a separate category and is dimensioned at European level. FCR, which is not part of the three types of flexibility studied, is therefore not further studied and considered explicitly (based on ENTSO-e dimensioning and allocation) in the adequacy assessment.

RELATION BETWEEN FLEXIBILITY AND RESERVE CAPACITY [FIGURE 3-19]

Relation with balancing
(determining the reserve capacity needs is out of scope of the study)



– **Part of the flexibility cannot be covered by the market and results in residual imbalances to be covered by FRR (aFRR/mFRR)**

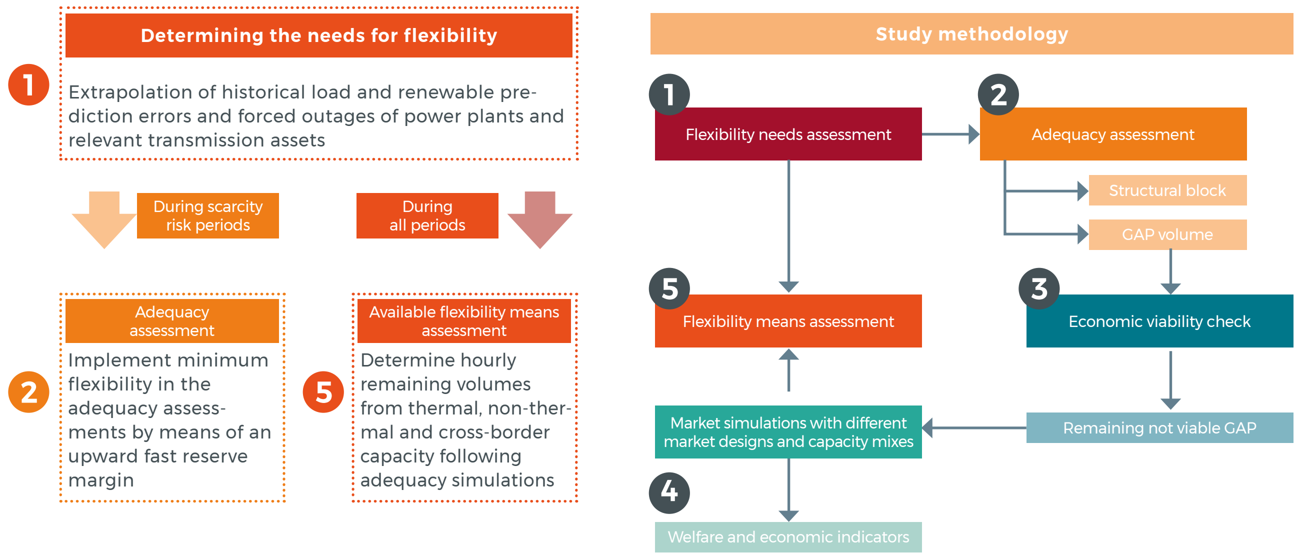
– **FCR is a separate flexibility type, determined on the level of the synchronous area (including N-1 conditions)**

3.4.3. Methodology to assess available flexibility means

After the flexibility needs are determined, the available flexibility means in the system are assesed. Figure 3-20 shows that this is conducted by means of two steps :

- by integrating the required minimum flexibility needs in the adequacy assessment and ensure the **availability of this flexibility during periods with a scarcity risk**. This is based on the upward fast flexibility needs which are required to cover forced outages and prediction risks which can occur during periods with an elevated residual load. This volume is modelled explicitly in the adequacy simulations and contributes to the adequacy needs of the system (Section 3.4.3.1).
- assessing the **available flexibility means during all periods** by means of an ex post analysis on the adequacy simulation results (also during periods without scarcity risk). Based on the hourly dispatch of all generation, storage and demand-side management units, and their technical characteristics, the available flexibility from hour to hour is assessed and compared with the required flexibility needs (Section 3.4.3.2).

METHODOLOGY TO ASSESS THE AVAILABLE FLEXIBILITY MEANS [FIGURE 3-20]



3.4.3.1. AVAILABILITY DURING PERIODS WITH SCARCITY RISKS

The methodology for the adequacy study simulates the Belgian day-ahead while taking into account the European market coupling. ANTARES simulations are based on a perfect foresight. This means all outages and renewable prodution is known in advance on a week-ahead basis, while forecast variations and unexepected outages within a day are not modelled. This means that markets occurring after the day-ahead, such as the intra-day and the balancing markets are not modelled.

The availability of flexibility can be included in the market simulations by means of additional constraints ensuring that available capacity in the system covers, on top of the electricity demand, the required flexibility needs. This way, flexibility impacts the adequacy needs of the system. A similar approach was already conducted for upward reserve capacity (FCR, aFRR and mFRR) being modelled in previous adequacy studies. In other words, a capacity meeting the technical requirements of reserve capacity was set aside to cover residual system imbalances that occur after day-ahead.

Taking into account the full flexibility needs in the adequacy assessment would oversize this margin as the risk of facing certain prediction errors (lower variable generation) is substantially lower during periods with scarcity. However, in order to ensure that sufficient flexibility (which will include reserve capacity) is available during peak demand periods, **the upward fast flexibility needs** are integrated into the adequacy simulations. These will therefore replace the FRR reserve capacity constraints formerly modelled. Indeed, even during peak demand periods, the system needs flexibility to deal with forced outages of generating units and transmission assets, as well as some forecast errors of renewable generation (although this will be rather low as it is not likely to face high renewable generation during periods with scarcity risk). This flexibility need is determined by means of studying the fast flexibility needs (without taking into account demand or forecast errors of the decentral 'must run' generation units such as CHP, Run-of-River Hydro, etc.) during the 5% highest residual load periods:

- the total load and the decentral 'must run' generation forecast errors are not taken into account as the total load profiles and must run profiles used in the adequacy analysis already take into account the maximum load. The maximum potential load at the moments will not be exceeded anymore due to forecast errors ;
- the renewable forecast errors are taken into account but the renewable profiles are expected to represent low renewable generation during periods with scarcity risk. There will be a low risk of facing large overestimations of generation ;
- the forced outages are taken into account because all generation units are assumed to be dispatched. Furthermore, flexibility needs have to cover the dimensioning incident at all times, set by the largest generating unit or HVDC-interconnector.

Note that the FCR, estimated at 100 MW, is kept as a separate reserve capacity type in the simulations. However, besides FCR and the upward fast flexibility needs, no additional constraints concerning flexibility are implemented into the adequacy model as:

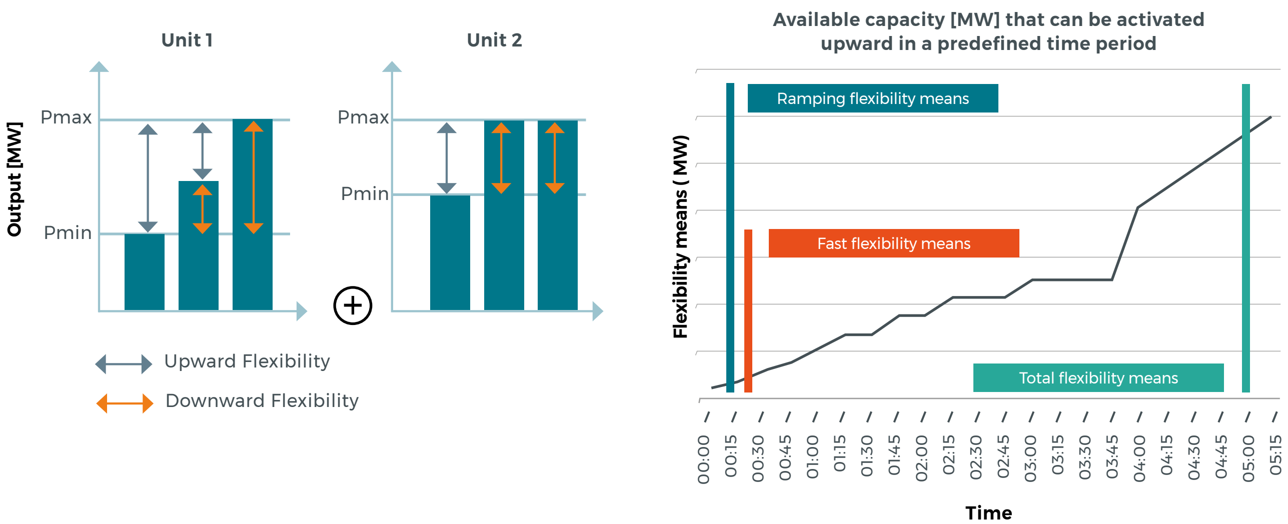
- firstly, the flexibility units reserved for the upward ramping flexibility needs are are found to already be provided when enforcing the fast flexibility needs in the simulations;
- secondly, it is considered that the slow upward flexibility needs (with the delay of five hours) enables most of the Belgian/European units to activate flexibility) for which slow flexibility is assumed to be sourced via a liquid intra-day market);
- thirdly, the downward flexibility is not modelled as it is less relevant for upward adequacy and studied by means of the ex post analysis in the next section. However, the availability of these flexibility types during periods with low scarcity risks are further investigated in the next section.

3.4.3.2. AVAILABILITY DURING ALL PERIODS (INCLUDING PERIODS WITH SCARCITY RISK)

The adequacy assessment does not explicitly integrate all types of flexibility and does not enforce the fast flexibility during periods with low risk towards scarcity. Therefore, an ex post analysis is conducted where the available flexibility means are calculated based on the hourly results of the adequacy simulations.

Figure 3-21 (left) shows that for each Belgian unit, the scheduled output of the unit allows the unit to provide up- and downward flexibility to their minimum stable power and maximum available power respectively. This can be calculated for each hour of the climatic years run in the adequacy model.

ASSESSMENT OF AVAILABLE FLEXIBILITY OF ONE UNIT (LEFT) AND AGGREGATED OVER ALL CAPACITY INSTALLED (RIGHT) [FIGURE 3-21]



For each hour, the available volume of flexibility from this unit over the period (1 min until 5h) based on its technical characteristics as outlined in Section 2.8.3.

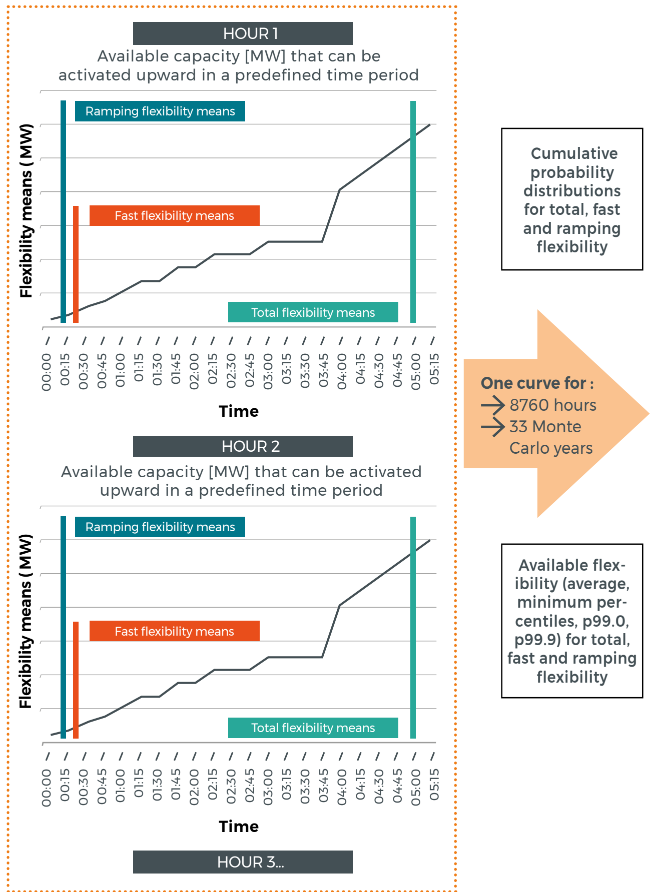
- For **thermal capacity**, the plant parameters (maximum power, ramp rate, minimum stable load, start-up / shut-down time, minimum up / down time) are used as well as the hourly power schedule of the units to assess the flexibility that the unit can provide;
- For **units with energy constraints** (demand-side management, combined-heat and power, pumped storage and batteries), the additional storage limitations are considered in the calculation. The unit provides flexibility (based on its technical parameters, its status on the day-ahead market but also its level of storage or maximum duration of activation) until its reservoir is completely full or empty, or the demand-side management, CHP limits are exceeded. Therefore, their flexibility is limited across time;
- For **renewable capacity**, the ability to deliver downward flexibility potential is considered. This takes into the limited predictability of this type of generation into account;
- For **cross-border flexibility**, the remaining available interconnection capacity (ATC) after day-ahead trading. Additionally, a fixed reserve sharing capacities is considered as fast flexibility which is currently considered firm in Elia's reserve capacity dimensioning.

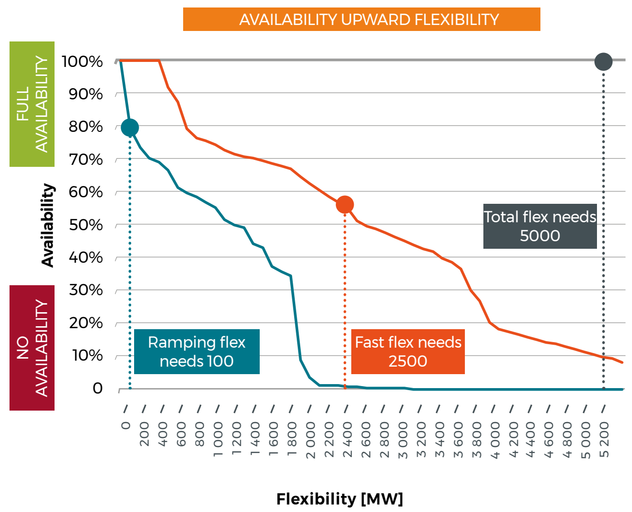
For every hour, each unit will have the up- and downward flexibility it can free in 1 minute, 15 minutes, 30 minutes, ..., up to 5 hours. When these profiles are aggregated, the total flexibility for each hour which can be delivered between 1 minute and 5 hours is shown Figure 3-21 (right). This results in one flexibility profile per hour for which the available ramping, fast and total flexibility can be distinguished. Note that the total flexibility expresses the capacity which can be used to cover the fast and the slow flexibility.

When the curves of each simulated hour (8760 hours for each of the 33 Monte Carlo years), as shown in Figure 3-22, the statistics can be compared with the flexibility needs:

- by means of key statistics such as the average, minimum available flexibility, or by means of percentiles expressing the minimum availability (e.g. 99.0% and 99.9%)
- by means of the cumulative probability distribution. The periods 5 hours and 15 min and 1 minute are used as a reference to determine the availability level of total, fast and ramping flexibility. A level of 100% represents a guaranteed availability while 0% represents that the corresponding flexibility volume is never available in the system.

ILLUSTRATION OF THE AGGREGATION OF AVAILABLE FLEXIBILITY (LEFT) AND AVAILABILITY OF TOTAL FLEXIBILITY PER FLEXIBILITY TYPE (RIGHT) [FIGURE 3-22]





	2025	[MW]		
		Total Flexibility	Fast Flexibility	Ramping flexibility
UP	Average			
	P99.0 / P99.9			
DOWN	Average			
	P99.0 / P99.9			

4 Results

This chapter presents the results of the electricity market modelling and flexibility assessment. The scenarios, sensitivities, assumptions and methodology are explained in detail in the previous chapters. The presented results are always obtained through a combination of simulating multiple climate years and 'Monte Carlo' draws on the unavailability of units.

The results are structured in the following way:

First the **adequacy requirements** are assessed for the 'Structural Block' and the 'GAP volume'. This is done by calculating the needed capacity in the 'CENTRAL' scenario, as well as across a large amount of sensitivities (European assumptions, grid, national sensitivities). A comprehensive comparison with previous adequacy study results is conducted in order to highlight the major changes (Section 4.1).

Afterwards, an **economic viability check** is performed on all of the existing and new capacity assumed in the 'CENTRAL' scenario with the possibility to invest in additional new capacity or extend the lifetime of existing capacity. The remaining 'not-viable GAP' is then calculated for each time horizon. Several sensitivities will also be applied to highlight the impact of a price cap increase or additional 'in-the-market' capacity (Section 4.2).

Several scenarios to fill the 'not-viable GAP' are constructed. Those are used in both the flexibility means and economic assessment.

The **analysis of the flexibility needs** presents the results of the statistical analysis of prediction and forced outage risks. The results show the total flexibility needs, the minimum flexibility needs during periods with scarcity risk, an analysis of the drivers impacting the flexibility needs and a sensitivity analysis (Section 4.3).

While the flexibility needs during periods with a scarcity risk are modelled in the adequacy assessment, the analysis of the **available flexibility means** presents the results of the installed flexibility and the available operational flexibility in each hour represented in the adequacy simulations. Available flexibility is compared with the flexibility needs (Section 4.4).

Finally, an **economic assessment** of different policy options is conducted. This includes several capacity mixes to guarantee that the needed 'not-viable GAP' is identified. On top of the resulting energy mix, wholesale prices and import/export balances of the country, differences in welfare and costs of the system are analysed (Section 4.5).

4.1. Adequacy requirements

The adequacy assessment is performed according to the methodology described in Chapter 3. **This methodology is 'state-of-the-art' and in line with the European resource adequacy assessment**. A large number of scenarios and sensitivities has been assessed such as presented in Chapter 2. The 'CENTRAL' scenario is based on the 'draft NECP' and the 'Energy Pact' for Belgium.

4.1.1. 'Structural block' volume requirements

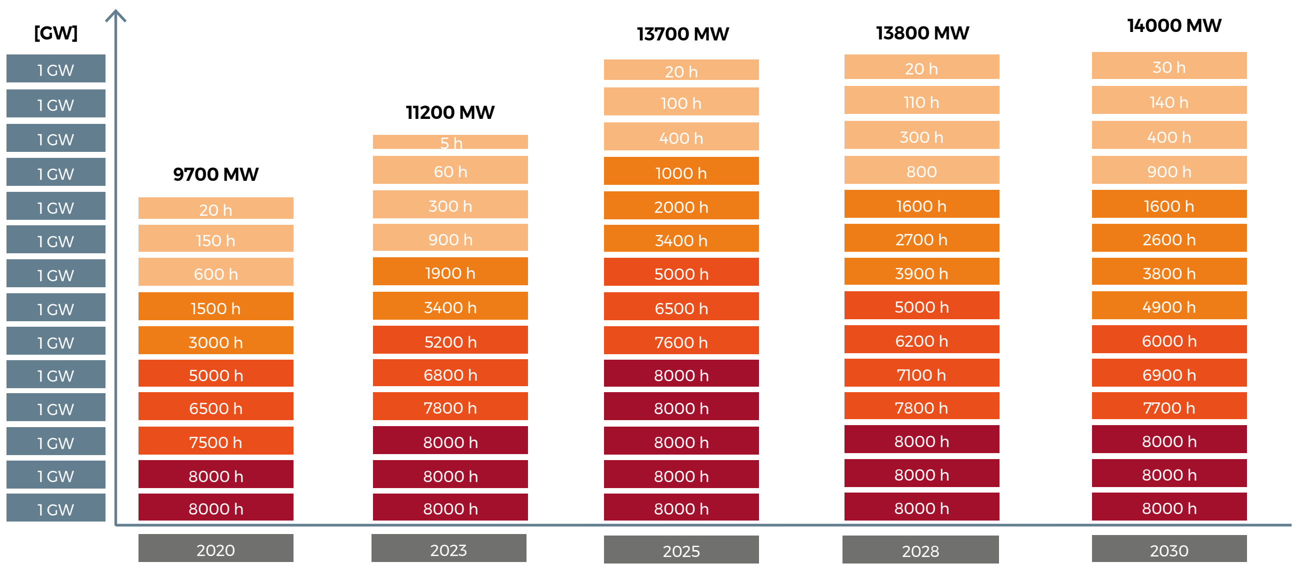
The 'structural block' volume is the additional capacity needed to ensure an adequate system after taking into account RES, nuclear capacity and the required volume identified in the assessment on flexibility needs during scarcity situations. The needed capacity is calculated as if Belgium would be isolated. More details on the definition can be found in the methodology chapter, Section 3.1.1.

The **'structural block' can be filled by any kind of capacity** (existing/new market response, existing/new CHP, existing/new storage, imports, existing/new gas-fired generation, existing/new oil-fired generation, etc.).

The 'CENTRAL' scenario uses the 'draft NECP' submitted by Belgium to the EC as the basis for consumption, RES and nuclear. The consumption is incremented with the flexibility needs during scarcity situations, as calculated in Section 4.3.

The volumes as well as the average amount of hours during which a certain capacity is needed are shown in Figure 4-1 for the different time horizons. From a technology neutral point of view, such a figure could be used to estimate how many hours a certain volume is needed.

STRUCTURAL BLOCK VOLUME IN THE CENTRAL SCENARIO WITH ASSOCIATED HOURS DURING WHICH A CERTAIN CAPACITY IS NEEDED [FIGURE 4.1]



EXPLANATION OF THE EVOLUTION:

The 'structural block' increases towards 2025. This is linked with the nuclear phase-out calendar. As the 'CENTRAL' scenario assumes a third of the nuclear fleet is unavailable, the nuclear phase-out amounts to a delta of 4 GW between 2020 and 2025.

After 2025, the 'structural block' volume increases slighty, which is linked to a moderate increase of the consumption in the 'CENTRAL' scenario (linked to electrification) compensated by the addition of renewable capacity in Belgium.

The amount of hours during which a certain volume of capacity is needed is slightly decreasing from 2025. This is linked to the increase in renewable capacity and is mainly driven by wind additions.

In 2030, there still is a need for around 6 GW 'baseload' capacity (>6000 h) in Belgium. Such capacity could be provided by several means (including imports) which will depend on the capacity mix that will be installed in Belgium and in neighbouring countries. Depending on the time horizon, there is around 2 GW needed for around 200 hours a year.

4.1.2. 'GAP volume'

The 'GAP volume' sharply increases from the moment when the first nuclear reactors are planned to be decommissioned (winter 2022-23).

A large amount of sensitivities were assessed, which leads to the conclusion that a structural need for new capacity emerges when the first nuclear units start to be phased out in 2022. This need further increases as the nuclear phase-out calendar progresses.

While the 'structural block' gives an indication of the needed capacity in Belgium when already counting on RES and nuclear capacities, the 'GAP volume' is the required capacity in Belgium after removing market response, storage, CHP and imports (based on the cross-border market capacity assumptions and energy availability abroad) from the 'structural block'.

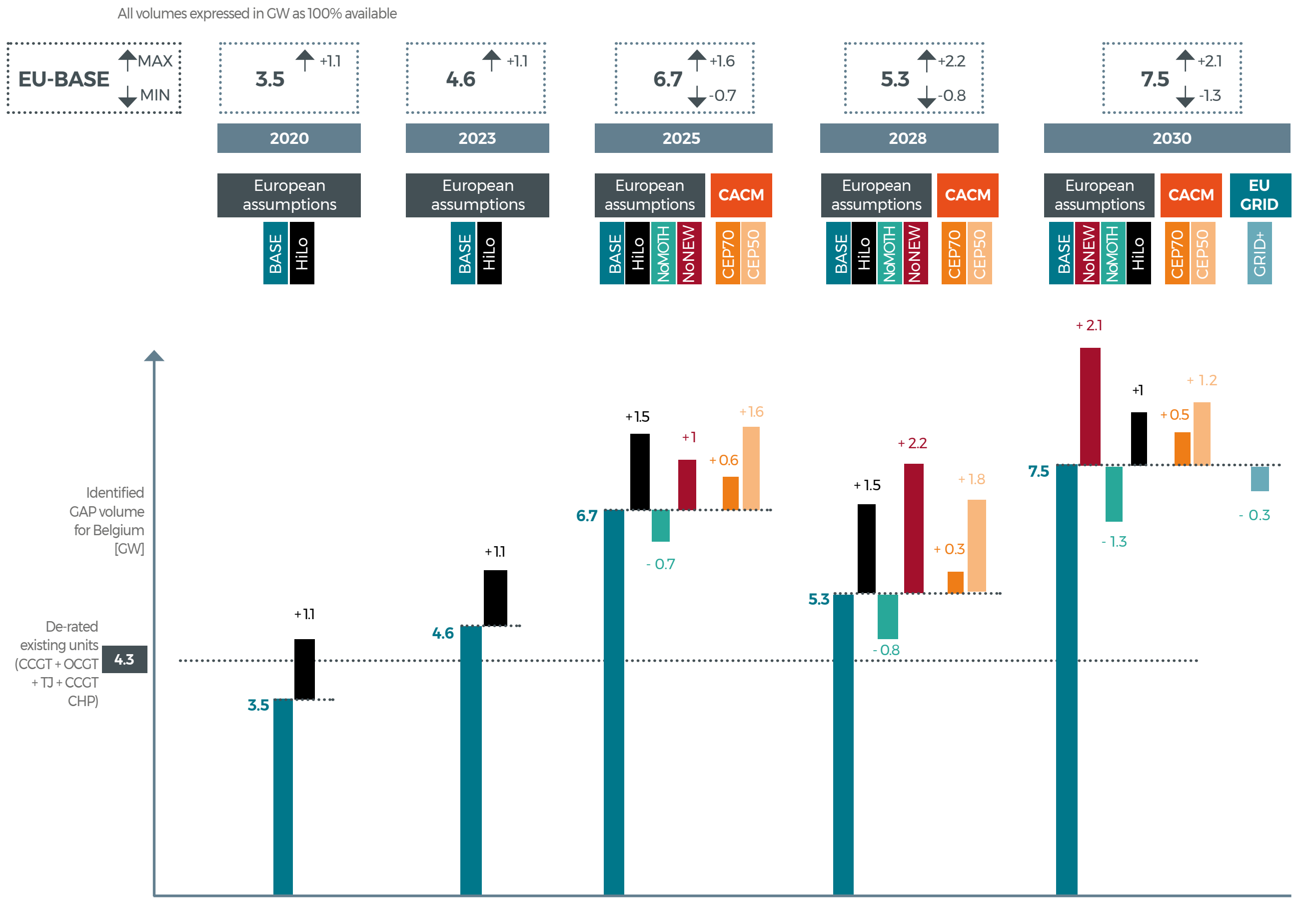
The 'GAP volume' can be compared to the needed capacity calculated by Elia in previous adequacy studies. It is important to mention that the **'GAP volume' is assumed 100% available** without energy or activation constraints and without technology requirements or other specific characteristics.

In order to fill the 'GAP volume', a certain derating of the installed capacity needs to be applied (depending on the technology and its associated characteristics). In order to evaluate the contribution of different technologies to the adequacy of the system, several sensitivities were simulated and the results are given in the following sections.

Evolution of the 'GAP volume' on the 'CENTRAL' scenario ('Energy Pact' and 'draft NECP') for Belgium with different European and grid assumptions:

As Belgium is strongly depending on imports for its adequacy, the results are provided with a view on the different European scenarios and sensitivities (see Chapter 2 for more information on the detailed assumptions). Figure 4-2 summarises those results.

OVERVIEW OF THE 'GAP VOLUME' (WITH IMPORTS CONTRIBUTION) FOR BELGIUM (WHICH ALREADY INCLUDES NEW MARKET RESPONSE, NEW STORAGE FACILITIES, NEW RES DEVELOPMENT, THE CEP RULES FOR CACM, THE PLANNED GRID REINFORCEMENTS) BASED ON THE 'DRAFT NECP' AND 'ENERGY PACT' FIGURES ('CENTRAL' SCENARIO). [FIGURE 4-2]



All simulations are based on the CENTRAL scenario for Belgium (based on draft NECP and 'Energy Pact'). It also takes into account an availability of nuclear in Belgium of 2/3 during winter as observed in the past years and which corresponds to the 'high impact low probability event' which is the basis scenario for the SR volume determination.

Scenarios	EU-BASE	The 'EU-BASE' scenario takes into account the latest known policies of all modelled European countries (nuclear and coal trajectories, expected new built gas generation, DSM and sotrage developments, CRMs, flow based, CEP rules, expected grid development,...)
	EU-HiLo	The 'EU-HiLo' scenario assumes 4 units unavailable during the winter in France, on top of 'normal availability'. This reflects past observations and 'high impact low probability events'. Such scenario is used to quantify the strategic reserve volume every year (which is in line with the EC State Aid approval).
Sensitivities	EU-NoNEW	The 'EU-NoNEW' sensitivity assumes no new built gas units in Europe (unless a support mechanism is in place). The scenario always ensures that countries with a market-wide CRM meet their adequacy criteria.
	EU-NoMOTH	The 'EU-NoMOTH' sensitivity assumes no mothballing of gas units in Europe. The scenario always ensures that countries with a market-wide CRM meet their adequacy criteria.
	EU-CEP70	The 'EU-CEP70' sensitivity assumes that only 70% of XB capacity is given for market exchanges (not less, not more). This is different to giving at least 70% which is assumed in the 'EU-BASE' scenario.
	EU-CEP50	The 'EU-CEP50' sensitivity assumes that only 50% of XB capacity is given for market exchanges (not less, not more).
	GRID+	The 'EU-GRID+' sensitivity assumes additional cross border developments abroad for 2030. Those exclude any projects in Belgium (on top of the already assumed in the 'CENTRAL' scenario)

RESULTS

Winter 2020-21

The 'CENTRAL' scenario results in a need of **3.5 GW** ('EU-BASE') to **4.6 GW** ('EU-HiLo'). Those results can be compared to the existing fossil generation (which is not deducted yet from the calculated 'GAP volume') of 4.3 GW (already de-rated for forced outages). Given that the 'EU-HiLo' scenario corresponds to the setting used for the strategic reserve volume determination that is performed each year before mid November, these results would indicate a need for a strategic reserve.

It is important to note that the present study does not aim to assess the exact volume required for the strategic reserve for next winters. Such an assessment will be performed by mid-November 2019 for the winter 2020-21 with an updated dataset.

Winter 2023-24

With two nuclear reactors to be decommissioned before winter 2023-24, the 'GAP volume' increases to a range between **4.6 GW** ('EU-BASE') and **5.7 GW** ('EU-HiLo'). In the latter scenario, the minimum new capacity ('GAP volume' minus all existing capacity (CCGT, CCGT-CHP, TJs, OCGT)) required would be 1.4 GW. This volume could further increase if there would be additional closures of existing units. A similar observation could be made by extrapolation for winter 2022-23. Given that the first nuclear reactor is to be closed before the winter 2022-23, the need for new capacity (assuming a linear interpolation between winter 2020-21 and 2022-23) would be of around 0.8 GW.

It is important to bear in mind that the current strategic reserve mechanism has only been approved until winter 2021-22. Action should therefore be undertaken by the authorities to cover this need in the period prior to the first delivery of the upcoming CRM. Several solutions could be considered to cover these needs. While the CRM remains the only solution to overcome the need as from 2025, for the transition period 2022-2025 both a continued use of a strategic reserve mechanism could be an option, as well as considering earlier delivery years of the CRM may provide a solution. Although timely action is required, at least both those options either already exist or are under full development. To the extent other credible solutions would exist, they should also be taken into consideration.

Winter 2025-26

For winter 2025-26, all nuclear units are decommissioned in the 'CENTRAL' scenario for Belgium. This leads to a **'GAP volume' ranging from 6.7 GW** ('EU-BASE') **to 8.2 GW** ('EU-HiLo').

The 'EU-BASE' scenario takes into account all known policies abroad (coal and nuclear phase-outs, renewables, etc.). Moreover, all countries with a market-wide capacity remuneration mechanism are ensured to meet their national reliability standards.

In the 'EU-HiLo' scenario, where 4 additional nuclear units in France are assumed unavailable for the whole winter, the need increases by 1.5 GW (from 6.7 GW) and reaches 8.2 GW. The uncertainty regarding the availability of nuclear capacity in France is explained in Section 2.6.3. Such events are hard to predict (even several months in advance) and their impact is significant for Belgium. Accounting for this scenario therefore makes the Belgian adequacy situation less dependent on such unpredictable evolutions of the French nuclear generation capacity (which are beyond the control of Belgian authorities). As a reminder, this scenario corresponds to the one used to dimension the volume of strategic reserve required for the next winters.

Given the high dependency on imports to ensure an adequate Belgian system, two additional sensitivities have been assessed:

- **'EU-noMOTH'**: the 'GAP volume' is reduced to **6 GW** resulting from the additional capacity considered in the market abroad (that was assumed 'mothballed' or 'closed' in the concerned winter period (11 GW) in the 'EU-BASE' scenario);
- **'EU-noNEW': 7.7 GW** of 'GAP volume' is needed. The increase is mainly explained by the removal of assumed new gas-fired capacity to be commissioned in Germany in the 'EU-BASE' scenario.

Additionally, sensitivities on the capacities made available for cross-border exchanges were performed. The constructed flow-based domains can be considered as rather optimistic in terms of available capacity for cross-border exchanges. Assuming lower cross-border capacities has an impact on the results and leads to higher 'GAP volume' requirements for Belgium:

- The **'CEP=70'** sensitivity results in **7.3 GW** 'GAP volume' needed. This sensitivity is constructed by ensuring that *'exactly 70%'* (rather than 'at least 70%') of RAM on each cross-border CNEC in the CWE region is made available for cross-border exchanges;
- The **'CEP=50'** sensitivity increases this volume to **8.3 GW.** This sensitivity assumes that *'exactly 50%'* (rather than 'at least 70%') of RAM on each cross-border CNEC in the CWE region is made available for cross-border exchanges.

Evolution after 2025

In all of the time horizons assessed, there is a structural need for new capacity (on top of the already assumed new capacity in the 'CENTRAL' scenario, i.e. new market response and new storage).

The decrease of the 'GAP volume' observed in 2028 can be explained by the increase in renewable capacity abroad, combined with the slower decommissioning rate of thermal generation (coal and nuclear) compared to the period between 2020 and 2025. There is an additional 87 GW RES planned in the 21 countries simulated between 2025 and 2028 (see Section 2.1.2). If well spread across Europe, such additions can contribute to an increase in the available capacity abroad when Belgium is in scarcity situations. If the RES level of 2025 would be kept for 2028, an additional 1.7 GW would be required in Belgium in the 'EU-BASE' scenario for 2028. Such a result highlights the high dependency of the country on developments which are 'beyond the control' of Belgium.

In 2030, the need increases further to a range between 7.5 GW ('EU-BASE') and 8.5 GW ('EU-HiLo'). Between 2028 and 2030, there is a net decrease of 23 GW thermal capacity which overtakes the further increase of RES abroad in that period (see Section 2.1.2).

An additional sensitivity was also performed to assess the impact of further grid reinforcements abroad ('EU-Grid+') – See Section 2.7.1. This leads to a decrease of 0.3 GW on the 'GAP volume' in Belgium.

4.1.3. Sensitivities on national assumptions

Another major driver for the 'GAP volume' requirements are the developments happening in Belgium. As requested by stakeholders, a large quantity of sensitivities are applied on the 'CENTRAL' scenario in order to highlight the impact on the needed 'GAP volume'.

Those sensitivities are applied independently from each other in order to separately quantify their effect. Figure 4-3 provides a summary of the changes in 'GAP volume' resulting from different assumptions for policy driven technologies and 'structural block'.

CHANGES IN GAP VOLUME WHEN CONSIDERING DIFFERENT ASSUMPTIONS FOR POLICY DRIVEN AND 'ENERGY PACT' CAPACITIES [FIGURE 4.3]

+ is higher 'GAP volume' needed
- means lower 'GAP volume' needed

Subject to viability check! -> figures only show impact on adequacy volume

	CENTRAL/EU-BASE	Sensitivity	2025	2028	2030
			6.7 GW	5.3 GW	7.5 GW
Policy driven	Draft NECP	IHS demand	+ 0.2 GW	+ 0.4 GW	+ 0.5 GW
		Lower electrification	- 0.2 GW	- 0.2 GW	- 0.4 GW
	Draft NECP	Low RES	+ 0.2 GW	+ 0.2 GW	+ 0.3 GW
		High RES	- 0.3 GW	-0.2 GW	- 0.3 GW
	Draft NECP/law	2 GW extension	- 1 GW	- 1 GW	- 1 GW
Structural block	Energy Pact	No new market response	+ 0.2 GW	+ 0.5 GW	+ 0.7 GW
		+ 1 GW	- 0.3 GW	- 0.4 GW	- 0.4 GW
	Energy Pact	No new storage	+ 0.3 GW	+ 0.4 GW	+ 0.5 GW
		Coo III (+600 MW)	- 0.3 GW	- 0.3 GW	-0.3 GW
	Existing CHP units	+ 1 GW	- 0.7 to -0.9 GW	- 0.7 to -0.9 GW	- 0.7 to -0.9 GW
		- 1 GW	+ 0.7 to 0.9 GW	+ 0.7 to 0.9 GW	+ 0.7 to 0.9 GW

4.1.3.1. POLICY DRIVEN SENSITIVITIES

Consumption sensitivities

The 'CENTRAL' scenario is based on the 'draft NECP' growth rates for the electricity consumption. In order to capture a certain range of uncertainties, two sensitivities were quantified. Those lead to around 200 MW volume difference (in both directions) for the year 2025. Towards 2030, the range around the 'CENTRAL' scenario increases to around 500 MW (upward and downward). Lower electrification than considered in the 'CENTRAL' scenario or higher growth rates can have a significant impact in the long run. On the shorter term, the impact is more limited.

RES sensitivities

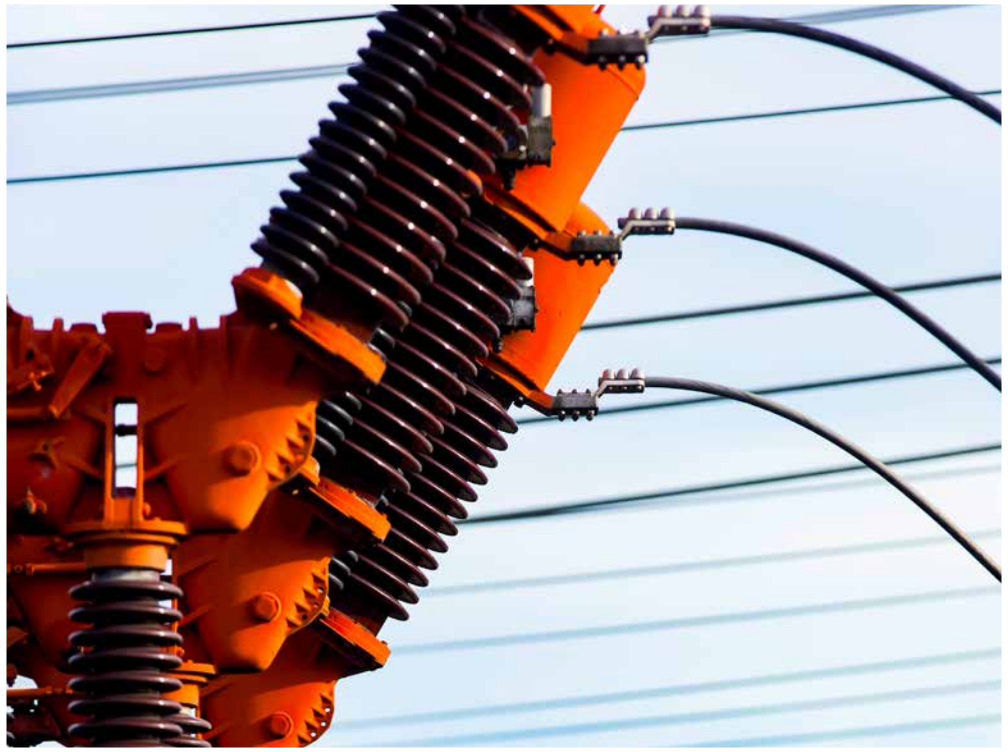
The 'draft NECP' aims to reach around a 40% RES-E share of the electricity consumption for Belgium in 2030. Deviations from this ambition could mean a slightly different 'GAP volume' is required. It is important to note that the sensitivities performed assume an additional 130 MW/year capacity of onshore wind and 300 MW/year of PV capacity in the 'high RES' sensitivity. It is also assumed that a total of 3 GW of offshore wind capacity will be installed by 2025 (against 2.3 GW in the 'CENTRAL' scenario). Those additions result in around 300 MW lower 'GAP volume' for Belgium. The contribution of intermittent renewable energy sources is limited given the fact that the dimensioning periods for adequacy are those periods when it is typically cold and there is little wind and no sun. More information on this matter can be found in BOX 12.

For a country such as Belgium, with similar weather patterns across the country (given its small size), additional wind or PV follows a similar production pattern as the existing capacity. Hence when the wind infeed is low at the coast, it generally is also low in other parts of the country.

Nuclear extension

Based on recent events on nuclear unavailability during winter months (see Section 2.5.1.2), the 'CENTRAL' scenario assumes that one third of the nuclear fleet is considered unavailable. As requested by several stakeholders, a sensitivity with an extension of 2 GW of nuclear capacity after 2025 was considered. This leads to a 1 GW reduction of the 'GAP volume'. This contribution is explained by the fact that only one nuclear reactor (out of the two) was assumed available (more information on this assumption and the historical unavailability of nuclear units can be found in Section 2.5.1.2).

Moreover, if those units would be extended, additional works would be required prior to the extension, leading to additional unavailabilities to be accounted for in the years prior to winter 2025-26. This was not quantified in this study.



BOX 12 CONTRIBUTION OF WIND AND PV TO ADEQUACY - DUNKELFLAUTE

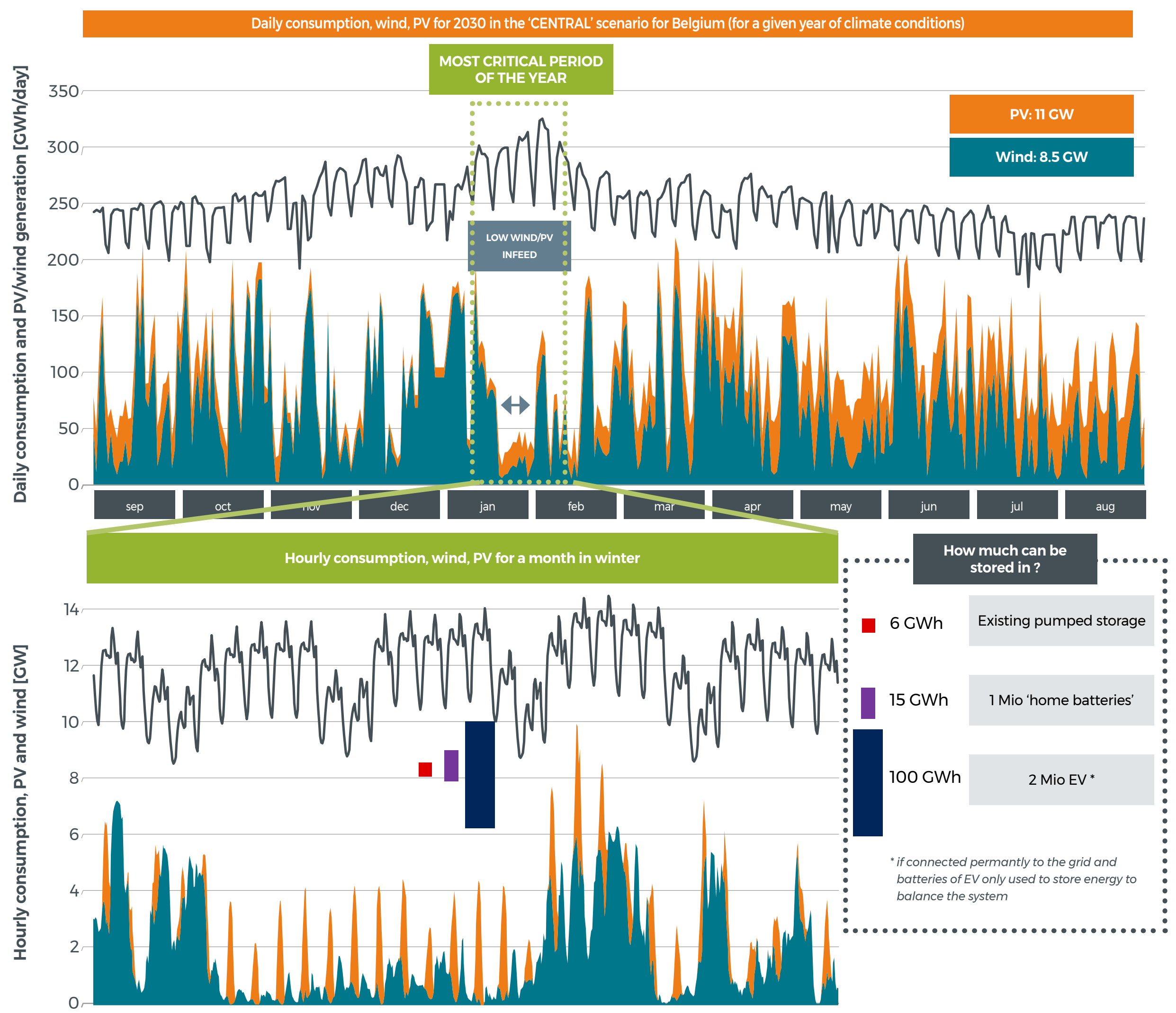
As illustrated in the study Elia published in November 2017 [ELI-3], the most dimensioning moments for adequacy are cold periods during winter (increase of consumption due to heating and no natural light due to the short daylight periods). Cold spells are usually accompanied by low wind generation, which leads to the so-called 'Dunkelflaute': no wind and little sun. During those periods, which can last from a few days to one or two weeks, the contribution of wind and PV is observed to be very low.

The top graph of Figure 4-4 illustrates an entire year with daily consumption patterns and wind and solar generation. While on a daily basis PV production can seem stable (with higher generation during summer months), wind fluctuations in daily production are noticeable over multiple days. Wind generation is usually following patterns of several days (with higher generation over a few days followed by low generation over the next days). Despite the fact that wind farms generally produce more on average during winter months, it can be observed that the most critical for adequacy is resulting from the combination of high consumption (usually linked to low temperatures) and low wind infeed. Such situations arise on a yearly basis but with different severity levels. A noticeable period was for example experienced during the month of January 2017 as covered by the press: [DER-1], [ENT-8].

The bottom graph zooms in on the most critical period of a given year (January – February) which is illustrated with an hourly resolution below the 'daily generation' chart for the 2030 'CENTRAL' scenario (which assumes an installed capacity of 4 GW of wind offshore, 4.2 GW of wind onshore and 11 GW of PV).

It can be observed that for almost two weeks in a row there is very low wind infeed. The remaining need (difference between the demand curve and infeed from renewables) has to be filled by other technologies such as thermal generation, imports and flexibility options (market response, storage). As an indication, the energy that has to be stored to cope with such periods, is higher than 1500 GWh for a week. Even if current or future storage technologies are fully used for this purpose they would not be able to meet this need. In those moments imports and thermal generation will be key to keeping the lights on.

'DUNKELFAUTE' - LOW WIND AND PV INFEED DURING HIGH CONSUMPTION PERIODS [FIGURE 4-4]



4.1.3.2. 'STRUCTURAL BLOCK' SENSITIVITIES

Market response

As requested by several stakeholders, two sensitivities were performed on the volume of market response.

The first sensitivity assumes no new market response (on top of the existing volumes in 2018 – 1.2 GW). The impact of this sensitivity increases over time as more market response is assumed towards 2030 in the 'CENTRAL' scenario (based on 'Energy Pact' figures):

- -0.3 GW of shedding and -0.5 GWh/day of shifting new market response by 2025 leads to an increase of the 'GAP volume' by 0.2 GW;
- -0.9 GW of shedding and -1.1 GWh/day of shifting new market response by 2028 leads to an increase of the 'GAP volume' by 0.5 GW;
- -1.3 GW of shedding and -1.5 GWh/day of shifting and of new market response by 2028 leads to an increase of the 'GAP volume' by 0.7 GW.

The second sensitivity assumes an additional volume of 1 GW new market response (with activation constraints) for each time horizon (on top of the already assumed new capacity based on the 'Energy Pact'). This volume was spread over the different categories of activation constraints (1h, 2h, 4h and 8h) while keeping the same share of each category. This leads to a reduction of the 'GAP volume' by 300 to 400 MW. The contribution to adequacy therefore amounts to between 30 and 40% on the installed capacity (if the same share of categories is kept).

As indicated in BOX 12, during low RES infeed and high consumption periods (which are the ones dimensioning the adequacy), there is a need for capacity that needs to be available during long periods. Given limitations and constraints on market response volumes (such as the amount of consumption that can be shifted over a day or the amount of hours during which it can be used), their contribution to adequacy is much lower than the installed capacity. Even if demand would completely flatline (assuming all consumption could be shifted within a day), a considerable 'GAP volume' would remain. Demand would need to be shifted over several days or weeks to be as effective as capacity without constraints.

Storage

Storage facilities as defined in the 'Energy Pact' (assumptions are detailed in Section 2.5.2.1) are already included the 'CENTRAL' scenario.

Removing all new storage capacity assumed would lead to an increase of the 'GAP volume' as follows:

- -1 GW new storage by 2025 leads to an increase of the 'GAP volume' of 0.3 GW;
- -1.3 GW new storage by 2028 leads to an increase of the 'GAP volume' of 0.4 GW;
- -1.5 GW new storage by 2030 leads to an increase of the 'GAP volume' of 0.5 GW;

The sensitivity with **an additional pumped storage unit of 600 MW** leads to a reduction of the 'GAP volume' by 300 MW.

As indicated in the BOX 12, the periods to be covered are lasting several days or weeks. The capacity assumed would need to be linked to a much higher volume of energy reservoir in order to provide a larger contribution to adequacy.

Small CHP or decentralised generation

Small scale generation which is linked to specific constraints or that are used for other purposes (e.g. providing heat, industrial processes) contribute to adequacy, depending on their technology and their ability to deliver maximum power while continuing to provide other required services. The contribution of an additional 1 GW or the removal of 1 GW of CHP units would lead to a reduction/increase between 700 MW to 900 MW on the needed 'GAP volume'. In the most optimistic case, such CHP units are fully driven by electricity prices and can deliver their maximum electrical output independently from any other processes (the derating is then only determined by their forced outage rate). On the other side, units that are required for other processes might not be able to provide their full output when needed.

BOX 13 CONTRIBUTION OF DIFFERENT TECHNOLOGIES TO ADEQUACY

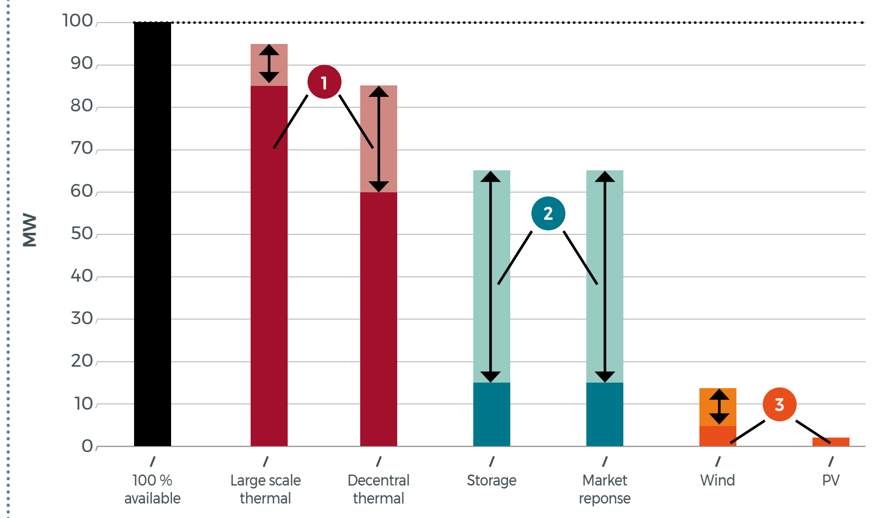
Although various technologies contribute to adequacy, not every technology contributes as much for the same installed capacity.

Based on the above sensitivities, it is possible to calculate the equivalent availability of additional capacity of different technologies. It is important to note that this only gives an indication per general type of technology. A more detailed analysis, including a more thorough categorization should be done if such parameters are to be used in the framework of a capacity remuneration mechanism. The ranges presented here are also subject to change depending on the market situation. They depend on many parameters such as the assumed capacity mix, the representation of a certain technology in the system, the situation abroad, etc.

Figure 4-5 summarises the findings. There are mainly three categories that should be distinguished:

- **Thermal** generation (including engines, diesels, turbojets, etc.): the contribution to adequacy is usually linked to the outage probability. In addition, several units might have other constraints (e.g. providers of heat or industrial processes) or are not fully driven by wholesale prices. In this case, the contribution to adequacy can be lower as the maximum electrical output of the unit is not always reachable (or there are no incentives to reach it);
- **Technologies with energy or activation constraints**: storage and market response are constituting the major part of this category. The most important driver for a higher or lower contribution is the size of the associated reservoir for storage and the activation constraints for market response. Note that other constraints could exist as well, e.g. a maximum number of activations during a certain time period (e.g. day or week). As indicated in the figure, the range is wide for those technologies and depends on the amount of hours they can continuously provide energy. Based on sensitivities performed, the results show that market response (as split over categories of a maximal duration of 1, 2, 4 and 8 hours in this study) contributes to around 40% of its installed capacity;
- **Weather driven technologies**: as highlighted in BOX 12, the contribution of wind and PV is low compared to their installed capacity as scarcity moments are usually linked to conditions with low wind and no sun/low temperature during the winter.

HOW MUCH DOES 100 MW INSTALLED CAPACITY OF DIFFERENT TECHNOLOGIES CONTRIBUTE TO ADEQUACY (INDICATIVE) ? [FIGURE 4-5]



Note that values and ranges shown are only indicative, and depend on the composition of the capacity mix in Belgium and abroad (which is in turn linked to the considered time horizon and the assumption on the GAP capacity mix).

1. Large scale thermal units can be dispatched at their maximum power during scarcity situations (if no other constraints are present). Contribution range will depend on technology, age,.. Smaller units that are decentralised, usually have other constraints (heat, industry,...). Some of them might be driven by other signals than only wholesale prices. Those have a slightly lower contribution to adequacy.
2. Storage and market response contribution depend a lot on the reservoir size and efficiency (for storage) as well as the amount of hours during which an activation can last (for market response). Other constraints can also play a role. The provided ranges were built considering capacities with different activation lengths.
3. Wind and PV are driven by weather. The range of contribution for wind reflects the difference between onshore and offshore wind.

4.1.4. New capacity needed to guarantee adequacy

To ensure a stable adequacy outlook and protect Belgium's adequacy for unforeseen and uncontrollable events in the other countries, there is a need for 3.9 GW of new capacity from 2025.

BETWEEN 2020 AND 2025

Assuming all existing units remain available for the future, the need for new capacity increases as the nuclear phase-out calendar is implemented. It is important to stress that the new capacity is required for events beyond Belgium's control. In this case the 'EU-HiLo' scenario was combined with the 'CENTRAL' scenario for Belgium. The 'EU-HiLo' scenario is the one used to quantify the strategic reserve volume and is in line with the EC's State Aid approval of the current strategic reserve mechanism.

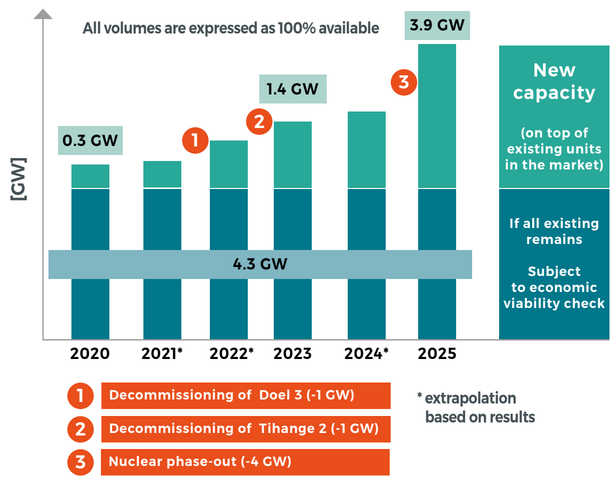
While the need is limited in the first years, it increases further for winter 2022-23 and 2023-24 (when in total 2 GW of nuclear units are planned to be phased out).

A higher increase is then observed between winter 2024-25 and 2025-26, when during the year 2025, 4 GW of nuclear capacity is set for decommissioning.

As mentioned in Section 4.1.2, it is important to bear in mind that the current strategic reserve mechanism has only been approved until winter 2021-22. Action should therefore be undertaken by the authorities to cover this need in the period prior to the first delivery of the upcoming CRM. Several solutions could be considered to cover these needs. While the CRM remains the only solution to overcome the need as from 2025, for the transition period 2022-25 both a continued use of a strategic reserve mechanism as well as considering earlier delivery years of the CRM may provide a solution. Although timely action is required, at least both those options either already exist or are under full development. To the extent other credible solutions would exist, they should also be taken into consideration.

Note that the years 2021, 2022 and 2024 were not simulated. Figure 4-6 gives a visual indication of what the needed capacity could be, based on extrapolations of the results.

NEW CAPACITY REQUIRED TO ENSURE AN ADEQUATE BELGIAN SYSTEM AND COVER FOR UNCERTAINTIES WHICH ARE 'BEYOND CONTROL' OF BELGIUM BETWEEN 2020 AND 2025 [FIGURE 4-6]



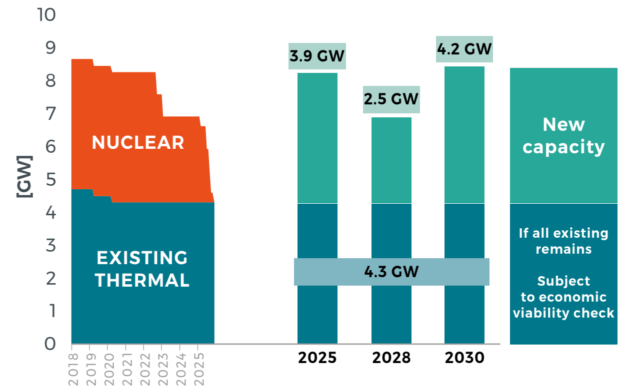
AFTER 2025

Assuming all existing units would remain after 2025, the new capacity required to ensure an adequate system in Belgium is 3.9 GW as from 2025. This number is based on the 'GAP volume' calculated considering the 'EU-HiLo' scenario for neighbouring countries together with the 'CENTRAL' scenario for Belgium. This volume already includes the contribution of imports, increases in market response and storage based on 'Energy Pact' values and an increase of RES and consumption growth based on 'draft NECP' values. It also assumes that in the future all existing units are not closing. An economic viability assessment is performed on the existing and new capacity to check whether those capacities are viable 'in-the-market' (see Section 4.2.2).

The needed new capacity follows the same variations as the 'GAP volume' identified for the 'EU-HiLo' scenario. The decrease for 2028 can be explained by large additions of RES across the whole of Europe compensating for the limited thermal decommissionings between 2025 and 2028. This effect is temporary however, as between 2028 and 2030 the additional thermal decommissionings in Europe would remove the margins created in 2028 and lead to a needed volume of 4.2 GW in 2030. To conclude, the need is substantial and structural over time.

NEW CAPACITY REQUIRED TO ENSURE AN ADEQUATE BELGIAN SYSTEM AND COVER FOR UNCERTAINTIES WHICH ARE 'BEYOND CONTROL' OF BELGIUM AFTER 2025 [FIGURE 4-7]

All volumes are expressed as 100% available. For nuclear, one-third of the unavailability was already accounted for in the equivalent volume in the figure below.



4.1.5. Comparison with other studies

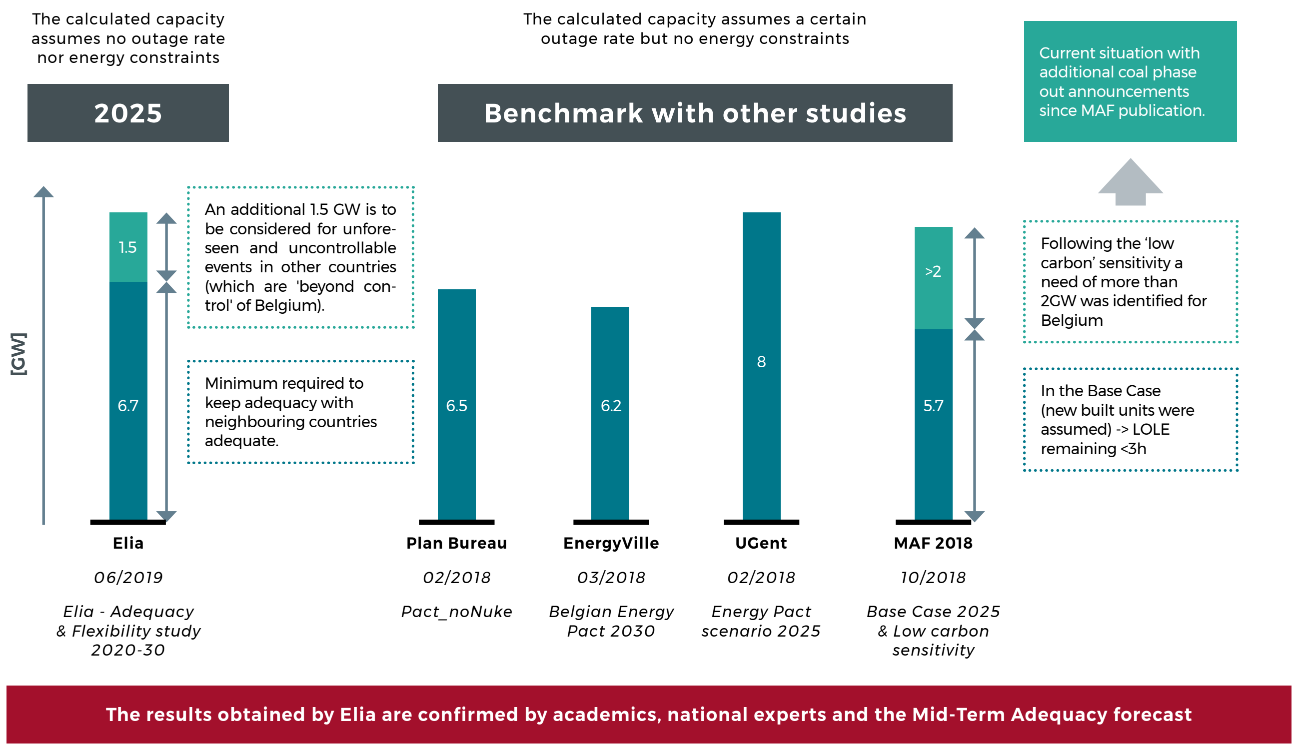
The adequacy results obtained in this study are confirmed by a large amount of recent external studies (academics, national experts, ENTSO-E MAF) and are in line with previous Elia adequacy studies.

4.1.5.1. OTHER PUBLIC STUDIES WITH RESULTS FOR BELGIUM

The results obtained in this study are comparable with a large number of studies performed by academics, consultants or independent experts. In those studies (based on different methodologies), the needed 'GAP volume' in Belgium expressed in thermal gas-fired generation capacity is between 5.7 and 8 GW. Figure 4-8 illustrates the results obtained in the different studies. Most of those studies were performed in 2018 with 'Energy Pact' assumptions for Belgium but did not yet integrate the additional thermal closures that were recently announced across Europe, nor the 'CEP min70%' rule.

In the ENTSO-E MAF 2018, the 'low carbon' sensitivity that was performed is similar to the 'EU-BASE' setting in the present study. For the 'low carbon' sensitivity several countries, including Belgium, were identified as not complying with their national adequacy criteria. The needed capacity to return Belgium to the legal adequacy criteria amounted to more than 2 GW. This result therefore confirms the needed capacity obtained in the present study.

NEEDED GAP 'GAP VOLUME' TO ENSURE THAT BELGIAN ADEQUACY REQUIREMENTS ARE MET AFTER 2025 [FIGURE 4-8]



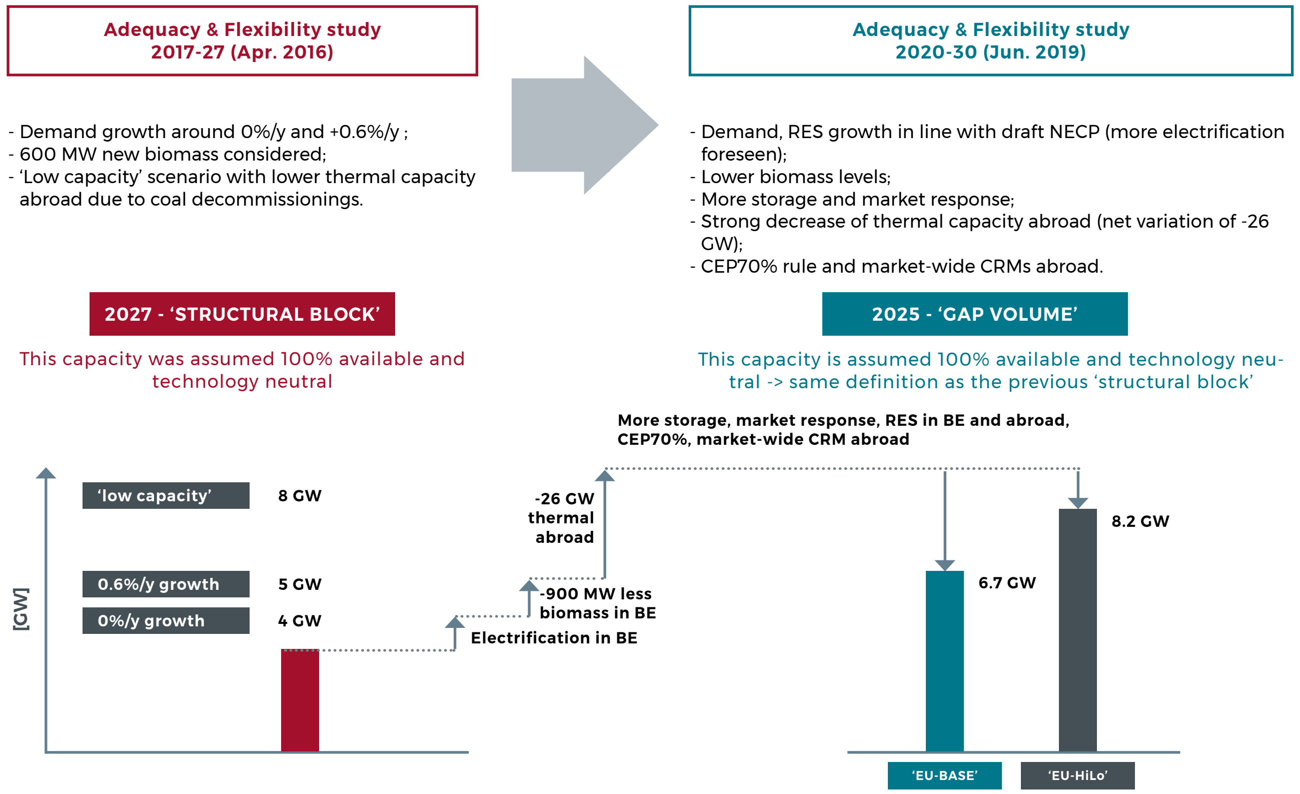
4.1.5.2. PREVIOUS '10-YEAR ADEQUACY AND FLEXIBILITY STUDY 2017-2027' (APRIL 2016)

The major change since the previous Elia '10-year adequacy and flexibility' study on the needed 'GAP volume' for Belgium is the energy availability abroad. As illustrated in Section 2.6.2, there will be 26 GW less thermal capacity in Europe in 2025 compared to the assumption taken in the previous '10-year adequacy and flexibility study' published in April 2016. This leads to an increase of the needs in Belgium as there is less energy available abroad when Belgium is in need for it. This is further analysed in Section 4.1.6. Comparing the assumptions with the previous study of April 2016, it can be observed that:

- There is 900 MW less biomass capacity in Belgium considered in the present study as 600 MW new-built was assumed in 2016 (which are to be added to the expected 300 MW to be closed, based on the draft NECP – WAM scenario);
- The current situation in the neighbouring countries is comparable to the 'low capacity' scenario of the 2016 study. While this scenario could have been considered as 'extreme' in 2016, it has now evolved to the 'EU-BASE' scenario;
- Additional market response and storage are now considered in Belgium and abroad. This contributes to adequacy although, as analysed in previous sections, their contribution to adequacy is limited by energy and activation constraints (compared to installed capacity);
- More RES is now considered in Belgium and abroad but for the reasons presented in previous sections, their contribution to adequacy is limited;
- The consumption forecast of the draft NECP (WAM scenario) lies in between the two scenarios that were investigated in the previous study (0%/year growth and +0.6%/year growth);
- The 'CEP70%' rule, and 'applying market-wide CRMs' to return countries to their national criteria, further decreases the needed volume. In the 'EU-HiLo' scenario (or other sensitivities performed), the impact of generation assumptions and cross-border capacity calculation assumptions was highlighted.

Figure 4-9 summarises those differences.

EXPLANATION OF CHANGES IN THE VOLUME FOUND COMPARED TO THE PREVIOUS 10-YEAR ADEQUACY AND FLEXIBILITY STUDY FOR BELGIUM (2017-2027) [FIGURE 4-9]



4.1.5.3. ELECTRICITY SCENARIOS FOR BELGIUM TOWARDS 2050 (NOVEMBER 2017)

When comparing the results related to adequacy of this study with the study 'Electricity Scenarios for Belgium towards 2050' ('BESET study') published in November 2017, similar observations can be made. The BESET study simulated the years 2030 (which was extrapolated back to 2025) and 2040. It is important to note that in the BESET study all other countries were assumed to be adequate (below 3 hours of LOLE) by adding the needed capacity to the system. In the present study this is only done for those countries having opted for a market-wide CRM (guaranteeing their adequacy criteria 'in-the-market').

While Belgian assumptions do not differ significantly (less biomass compensated by more storage and wind/PV) from the 'Base Case' scenario of the BESET study, the major change comes from the additional coal phase-out (or strong reduction) announcements in Europe that were not taken into account in the 'Base Case' of BESET. This concerns Germany, the Netherlands (although such coal capacity is in this study partly assumed to be converted to biomass), Italy, Spain, etc. In addition, more RES is considered abroad and the 'CEP min 70%' rule is applied for the calculation of cross-border capacities. All those effects lead to a net increase of the needed 'GAP volume' of about 1.2 GW.

In the BESET study, it was concluded that (at least) 3.6 GW of new capacity was needed in Belgium. This resulted from the following reasoning:

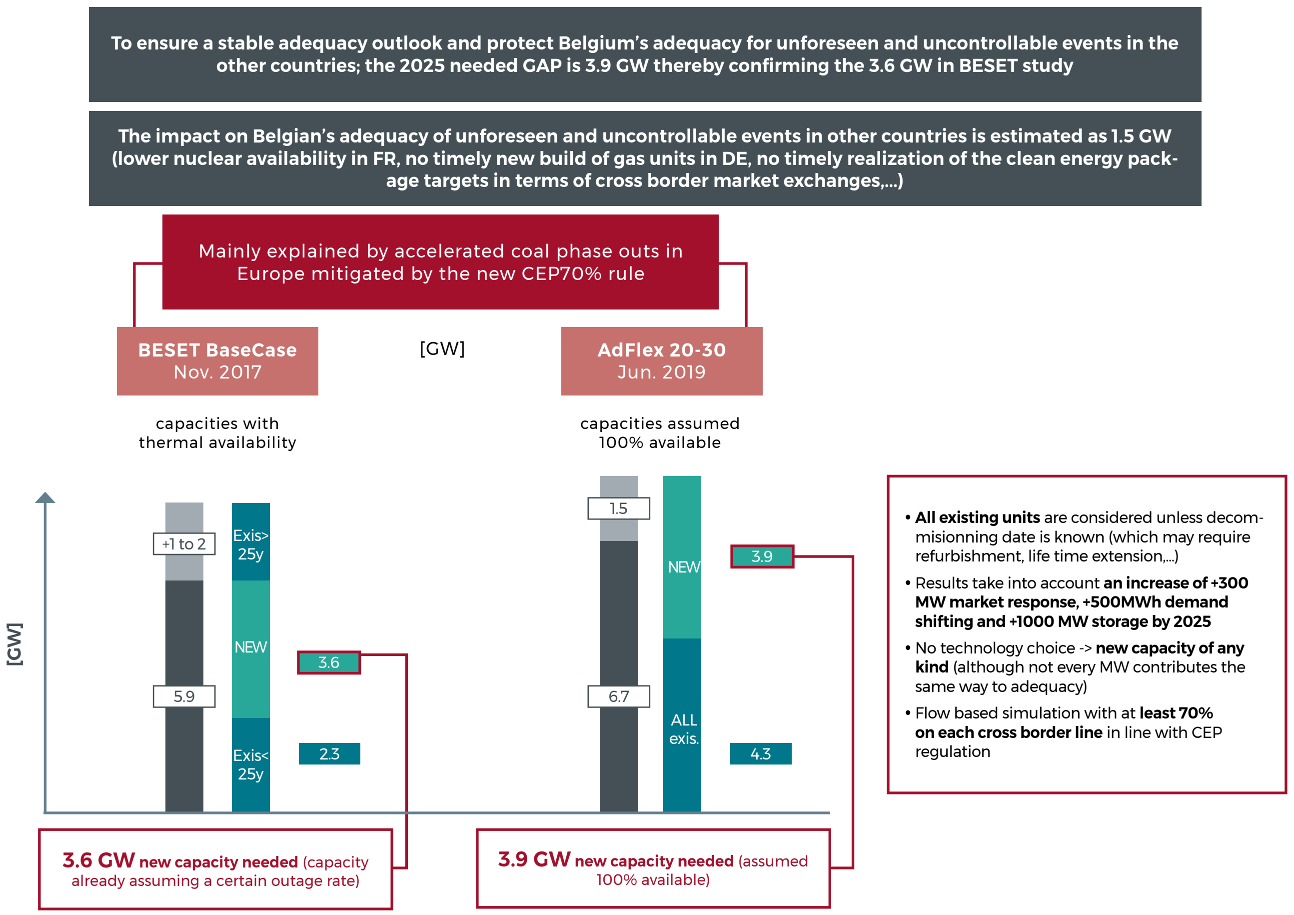
- A need of 5.9 GW was identified (not 100% available). It was assumed that recent units (< 25 years old) were covering part of this capacity (2.3 GW). The rest was complemented with new capacity (3.6 GW);
- This need is to be complemented with an additional 1 to 2 GW in order to cover uncertainties related to surrounding countries which are 'beyond the control' of Belgian authorities. Existing units that have reached their 25 years (assumed lifetime) were considered to cover this need in the future.

It is important to note that the 3.6 GW that was brought forward in the 2017 BESET study was already assuming a certain outage rate (of new thermal units). Without this outage rate, the equivalent 100% capacity equals 3.4 GW.

The 3.6 GW from the BESET study can be compared to the 3.9 GW of new capacity needed in the 'EU-HiLo' scenario for 2025. It can therefore be concluded that the present study confirms the requirements for new capacity as from 2025 as calculated in BESET.

In addition, the present study gives a view with a higher granularity on the need for the years in between 2020 and 2030 and takes all existing capacity into account.

NEEDED GAP CAPACITY, EXISTING CAPACITY AND LINK TO THE BESET STUDY [FIGURE 4-10]



4.1.6. Analysis of imports during scarcity events

Belgium is very dependent on imports to ensure its adequacy. When scarcity situations occur in Belgium, they are linked to at least one neighbouring country. Towards the future, this interaction of scarcity situations between countries will further increase.

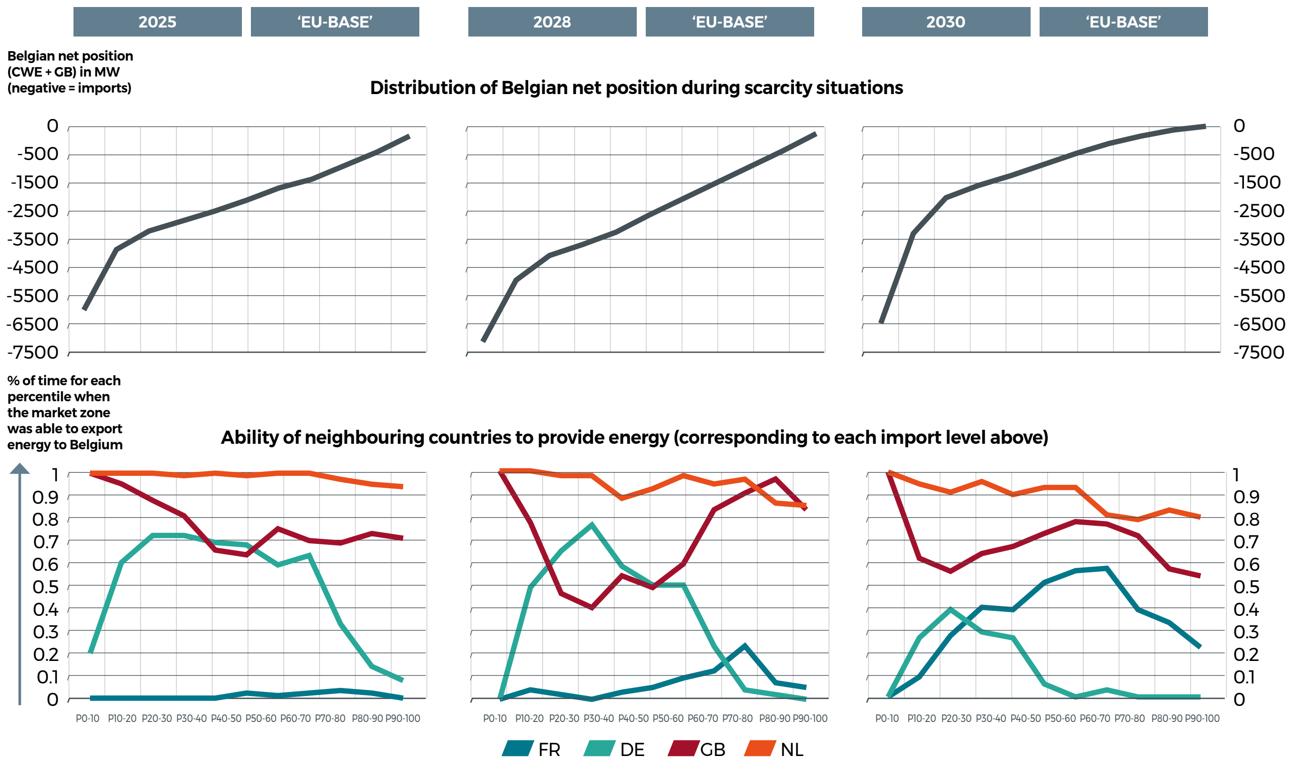
In order to assess whether the energy is available abroad and can be imported into Belgium, an in-depth look at the imported electricity during scarcity moments is provided. The results shown in the next figures are based on simulations where Belgium is adequate (current national adequacy criteria) for the given scenario. This means that the identified 'GAP volume' was filled with 100% available capacity. Figure 4-11 provides the values for the 'EU-BASE' scenario.

HOW TO READ THE CHART?

- Only the scarcity hours in Belgium are taken into account (when there is at least 1 MW of energy not served). The amount of hours corresponds to 3 hours on average per year;
- The upper chart shows the imports duration curve for Belgium when in scarcity (imports from CWE and GB hence the net position of Belgium). The imports during all scarcity hours are sorted from the highest import to the lowest. These are then clustered in 10 equally sized blocks (containing the same amount of hours) or 'percentiles';
- For each percentile in the upper chart, the capability of each neighbour to export energy towards CWE+GB is analysed. This is done by looking at the ability of each country to export energy to CWE+GB in the hours of each percentile (at a given import level for Belgium while in scarcity). It is important to note that the different countries also have borders with other countries than CWE+GB. It is therefore possible that a country imports from other regions in Europe while it is exporting to CWE (e.g. France imports from Spain (which has enough capacity) and then exports it to CWE+GB);
- The percentage of hours during which the neighbouring countries were able to export energy are shown. The higher the percentage, the more hours a given country was able to 'help' Belgium. The lower the percentage, the higher the simultaneity of imports between Belgium and the considered country, hence the simultaneity of scarcity situations.

Results for the 'EU-HiLo' scenario are available in Appendix F.1

NET POSITION OF BELGIUM (CWE + GB) DURING SCARCITY AND CAPABILITY OF OTHER COUNTRIES TO EXPORT ENERGY DURING THOSE MOMENTS [FIGURE 4.11]



FINDINGS FROM THE CHARTS:

- The import contribution increases between 2025 and 2028 and decreases again in 2030. This is also clearly observed in the 'GAP volume' required in Belgium and explained in Section 4.1.2;
- Belgium never reaches its maximum import capacity assumed in the 'flow-based' domain (7500 MW) during scarcity moments. This is explained by the fact that Belgium is always in simultaneous scarcity with at least one other country;
- In 2025, France has no or little moments when they can export energy towards CWE while Belgium is in scarcity. In other words, scarcity almost always happens simultaneously in France and Belgium. This slightly changes over time as scarcity situations in Belgium get more linked to scarcity situations in Germany and to a lesser extent also to the Netherlands.

It is important to note that even though the contribution of additional interconnections and additional cross-border capacity to adequacy can be limited – depending on the situation in neighbouring countries –, the most important benefit those investments bring are price convergence, in turn leading to improved overall welfare. Interconnections allow for an optimal sourcing of electricity from an integrated European market (all year long) and for a maximal utilization of renewable energy sources despite their natural intermittency.

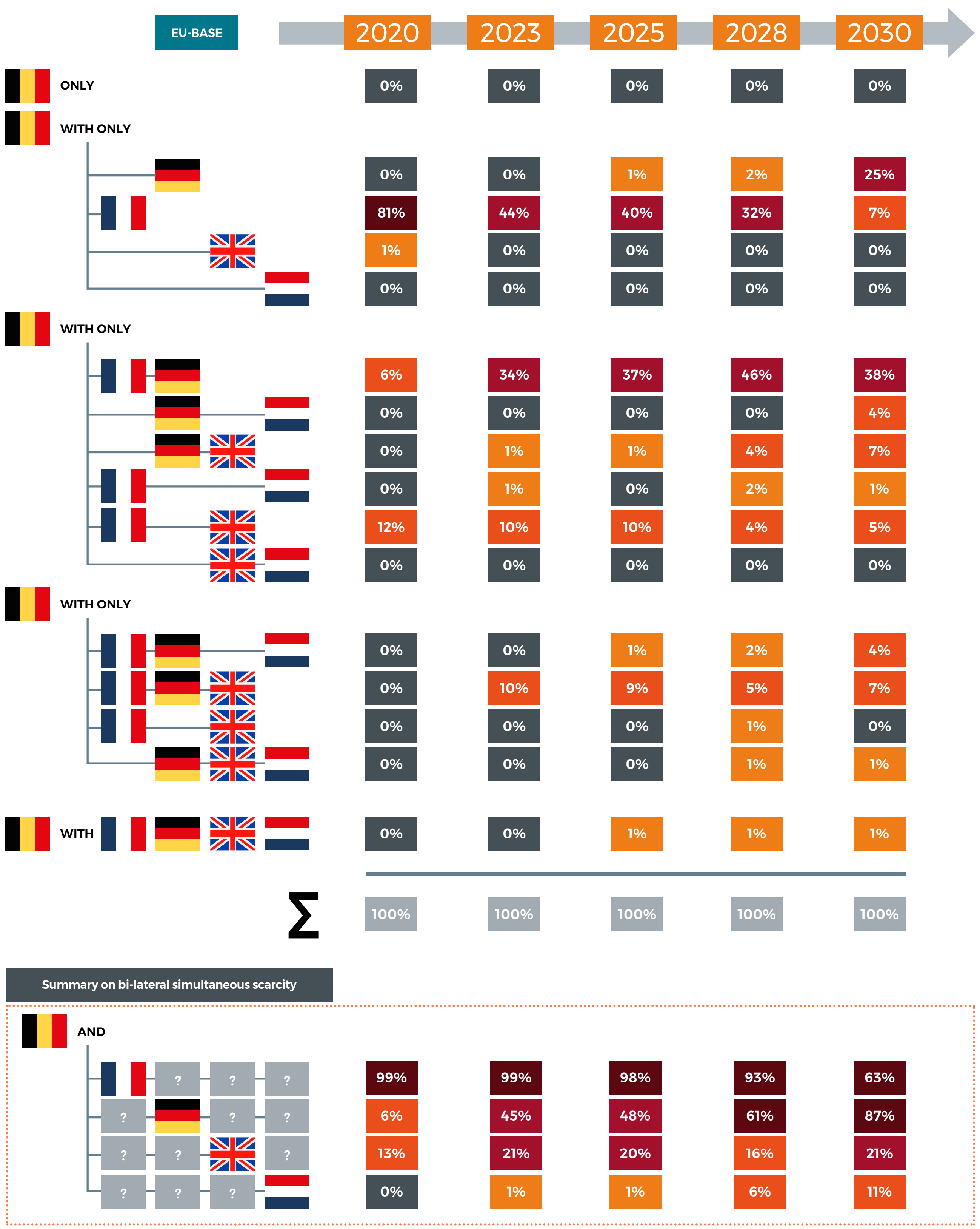
SIMULTANEOUS SCARCITY EVENTS ANALYSIS (SEE FIGURE 4-12):

It is also possible to look at the frequency of simultaneous scarcity events between Belgium and the neighbouring countries. Figure 4-12 provides an overview of the distribution of those simultaneous scarcity events for Belgium. In order to give a full overview for the reader and list all possible situations, all combinations of double, triple, quadruple and quintuple scarcity hours are indicated. The ratio shown on the figure is the percentage of hours of the total amount of scarcity hours for Belgium in the situation where Belgium nevertheless respects its adequacy criteria ('EU-BASE' scenario when 6.7 GW 'GAP volume' filled with 100% available capacity is considered). In other words, the total amount of hours analysed are the ones from all 'Monte Carlo' years when there is scarcity (the average of all 'Monte Carlo' years' LOLE being 3 hours).

SIMILAR FINDINGS TO PREVIOUS FIGURES CAN BE OBSERVED:

- Belgium is never in a scarcity situation alone. There is always at least one country in scarcity together with Belgium;
- In 2020, most of the simultaneous events are the hours when only Belgium and France are in scarcity;
- From 2023, France and Belgium are still presenting simultaneous scarcity situations but half of those hours are happening together with other countries (such as Germany). The removal of thermal capacity in other countries will make them more dependent on imports, hence in some situations this will coincide with scarcity events in Belgium and France;
- From 2025 to 2030, it can be observed that the simultaneous hours with France are decreasing, while those with Germany are increasing;
- More and more moments are consisting of triple scarcity situations (around 50% from 2023) and to a smaller extent of quadruple scarcity situations (around 10% from 2023). The majority of moments are triple scarcity situations with France and Germany. When adding those with Great Britain as well, they constitute around 45% of the scarcity events in Belgium.

SIMULTANEOUS SCARCITY EVENTS: CORRELATION BETWEEN BELGIUM AND NEIGHBOURING COUNTRIES [FIGURE 4-12]



4.2. Economic viability check of the 'structural block'

After evaluating the needed capacity to comply with the Belgian adequacy standards, an economic viability check is performed on all existing and new capacity to see whether this needed capacity would be realised without an additional 'in-the-market' intervention. This follows the methodology explained in Section 3.2.1 and takes into account investment costs and fixed costs (see Section 2.9.4) which are compared with energy market revenues to determine whether an investment or an existing unit is economically viable or not.

Only energy market revenues are considered although revenues from balancing markets can also represent an income for (at least part of) the installed capacity. However, at system level, it is assumed that such revenues would not overthrow the economic viability analysis, not in the least because (part of) the revenues from ancillary services replace revenues from the wholesale market (e.g. a reservation of capacity restricts the use of this capacity for selling energy at the electricity market at the same time).

It is important to note that:

- Only the minimum CAPEX and FOM values from the presented ranges in Figure 2-62 are used as the threshold for the investment decision or decision to maintain the unit in operation;
- The revenues from the most rewarding CO_2 scenario setting are taken into account. Those results are therefore always determined by the 'HIGH' CO_2 price scenarios (reaching 80 €/tCO_2 in 2030).

The economic viability check is performed on the 'CENTRAL' scenario for Belgium which already assumes certain new capacity will be developed (market response and storage), combined with both the 'EU-BASE' and 'EU-HiLo' scenarios for countries abroad.

4.2.1. Market revenues for existing and new capacity in 2020 and 2023

Based on the inframarginal rent analysis for 2020 and 2023, new capacity required to ensure adequacy is not viable 'in-the-market'.

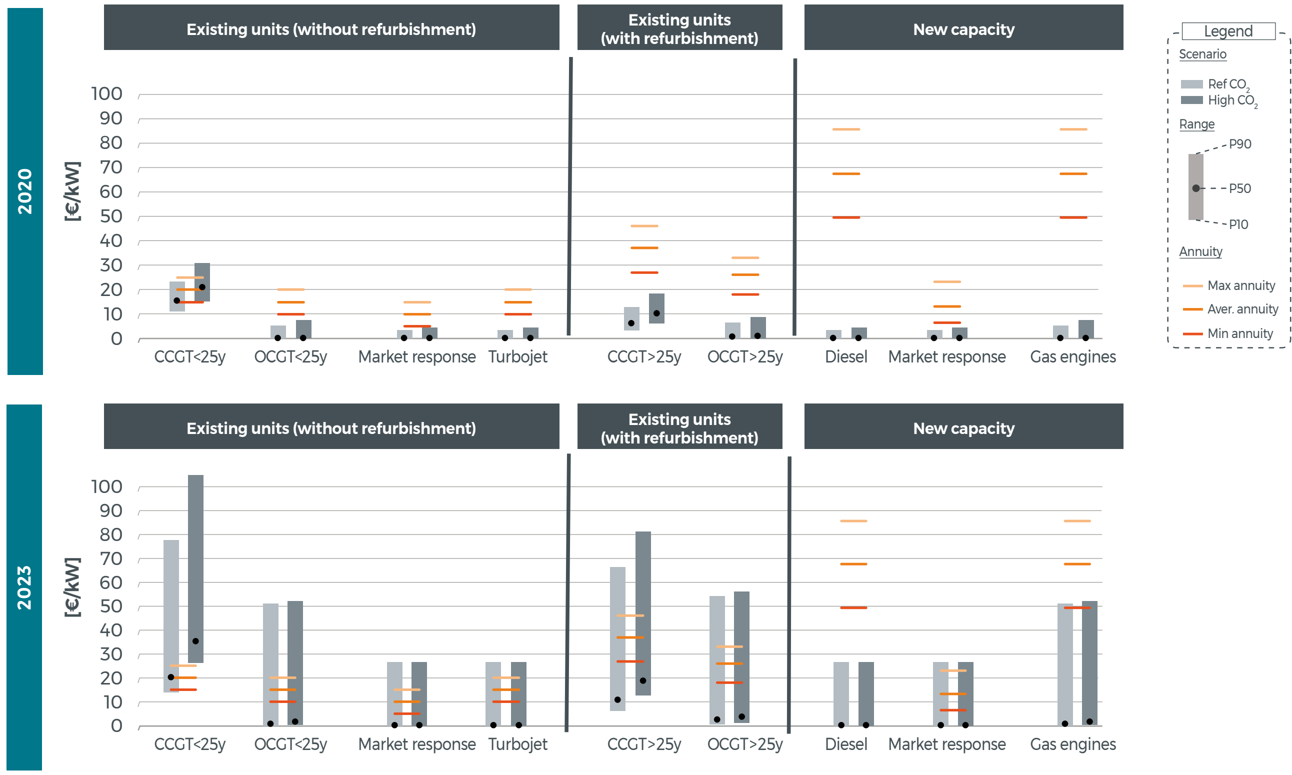
A simulation was performed assuming all existing capacity staying 'in the market' for 2020 and 2023 in the 'CENTRAL'/'EU-BASE' scenario. The market revenues of this situation are shown on Figure 4-13 for 2020 and 2023.

It can be observed that based on the inframarginal rent, only existing CCGT units (<25 years) would cover their FOM. This conclusion cannot be applied for other existing capacities. This would imply that those are at risk and could leave the market. The profitability of peaking units (OCGTs and turbojets) and market response is strongly impacted by the occurrence of scarcity periods.

For 2023, it can also be observed that the inframarginal rent volatility is higher due to thermal decommissionings in Belgium and abroad increasing the amount of hours with scarcity. Indeed, the scenario simulated in 2023 is not adequate with a need for 300 MW of capacity (in the 'EU-BASE') while the one simulated for 2020 has a margin of 700 MW (in the 'EU-BASE').

Moreover, based on the assumed costs and calculated revenues, it can also be stated that the wholesale market prices until 2023 are not expected to incentivise new-built capacity such as new CCGT, OCGT, diesel, gas engines or additional market response volume on top of the assumed volume in the 'CENTRAL' scenario. This fact also indicates that assumed market response volumes increase based on the Energy Pact figures are not guaranteed.

INFRAMARGINAL RENT FOR EXISTING AND NEW CAPACITY IN 'CENTRAL' SCENARIO FOR 2020 AND 2023 - EU-BASE [FIGURE 4-13]



4.2.2. Results of the economic viability check (after 2025)

In any of the scenarios, sensitivities and time-horizons analysed, if the current mechanism is kept, a large volume will have to be contracted 'out-of-market' (of which a large part is new capacity).

Performing the economic viability check for each time horizon after 2025 and for both the 'EU-HiLo' and 'EU-BASE' scenarios, results in a 'not-viable GAP' in Belgium of around:

- around 4 GW in 2025;
- around 3 GW in 2028;
- around 2 GW in 2030.

Note that in all the scenarios and sensitivities assessed there is always a significant 'not-viable GAP' identified. The decrease of the 'not-viable GAP' over time can be explained by higher market prices in CWE driven by higher CO_2 prices, less thermal capacity across Europe, combined with more market response (with high activation prices) on which countries are relying on for their adequacy. This leads to higher revenues in the market (this effect is also observed in 'EM+CRM' designs – see Section 4.5.2) but those are not sufficient to induce the necessary investments without additional intervention.

Figure 4-14 summarises the results in terms of economically viable existing and new capacity. **It is important to mention that the economic viability of the capacity is subject to the assumption that the identified 'not-viable GAP' is not filled. If this would be the case, the revenues would not be sufficient to maintain those units in the market.** This implies that as long as there is a 'not-viable GAP' the assumed market design, i.e. an energy-only market design, does not appear capable of fostering the necessary capacity to attain the reliability standard. Some investments could be triggered, but those are clearly insufficient to reach the targeted adequacy criteria.

Results of simulations show that while the 'GAP volume' is higher in the 'EU-HiLo' scenario, the 'not-viable GAP' stays similar to the one identified in the 'EU-BASE' scenario. This can be explained by higher prices in the 'EU-HiLo' scenario driven by lower availability of nuclear units in France.

While for 2025 and 2028, no new economically viable capacity was identified (on top of new market response already assumed in the 'Energy Pact'), in 2030 a certain amount of new capacity could be viable (as long as the 'not-viable GAP' is not filled). This would still result in a situation where Belgium would not meet its adequacy standards.

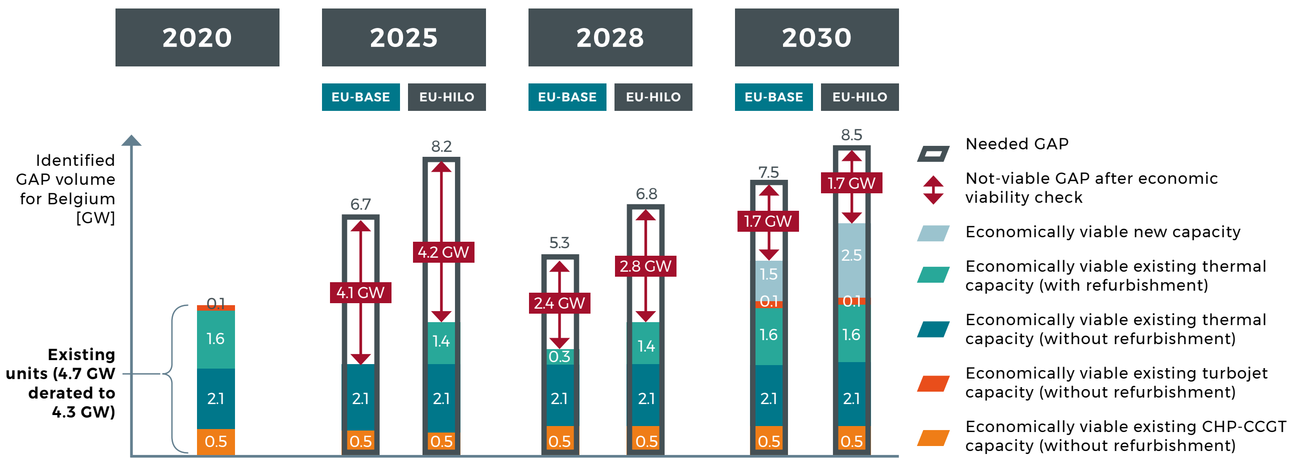
The starting point of the economic viability check (EVC) assumed existing and new CHP, storage and market response as laid out in the 'Energy Pact'. The existing and new additions were also analysed to derive their economic viability.

It can be concluded that for **CHP**, the existing capacities seem to be economically viable though it is very hard to estimate the economic viability given that the model used in this study only simulates the electricity market. On one side, CHP might require additional fixed costs linked to the higher complexity of the unit. On the other side, given a higher total efficiency (electricity + heat generation), it could capture higher electricity revenues as it would run more hours during the year (than standard gas-fired units). While existing CHP seems to be viable, new capacity is not (relying purely on electricity market revenues). For the reasons mentioned above, it could nevertheless be economically viable when taking into account the total picture (electricity + heat).

For **storage**, the EVC results demonstrate that additional storage would not be viable without support. It is important to mention that storage facilities that are assumed in this study are in reality not necessarily priced against wholesale market prices. They could benefit from additional incentives or be used for other purposes. For those reasons, they were not removed from the system when performing the EVC. In Figure 4-14 an indication of the additional volume required in the case of no new storage is provided.

Market response assumed in the 'Energy Pact' would be viable under the condition that the 'not-viable GAP' is not filled with additional capacity; hence Belgium does not comply with its adequacy criteria.

ECONOMIC VIABILITY (ON ENERGY MARKET REVENUES) REVEALS THAT A 'NOT-VIABLE GAP' OF MORE THAN 4 GW IN 2025 WOULD PREVAIL IF NO INTERVENTION. THE UNITS THAT ARE IDENTIFIED AS 'ECONOMICALLY VIABLE' ARE WITH THE CONDITION THAT A 'NOT-VIABLE GAP' PREVAILS (WHICH LEADS TO HIGHER PRICES ON THE MARKET) [FIGURE 4-14]



Storage	**New storage not viable** unless additional revenues or support			
Needed volume increase if no new storage	**+0.3 GW**	**+0.4 GW**	**+0.5 GW**	
Market response	Assumed new market response viable (under the condition that the identified 'not-viable GAP' is not filled)			
CHP	Existing CHP is economically viable. New CHP is not viable (unless support is given or it is built for other purposes)			

BOX 14 – RESULTING REVENUES AFTER THE ECONOMIC VIABILITY CHECK

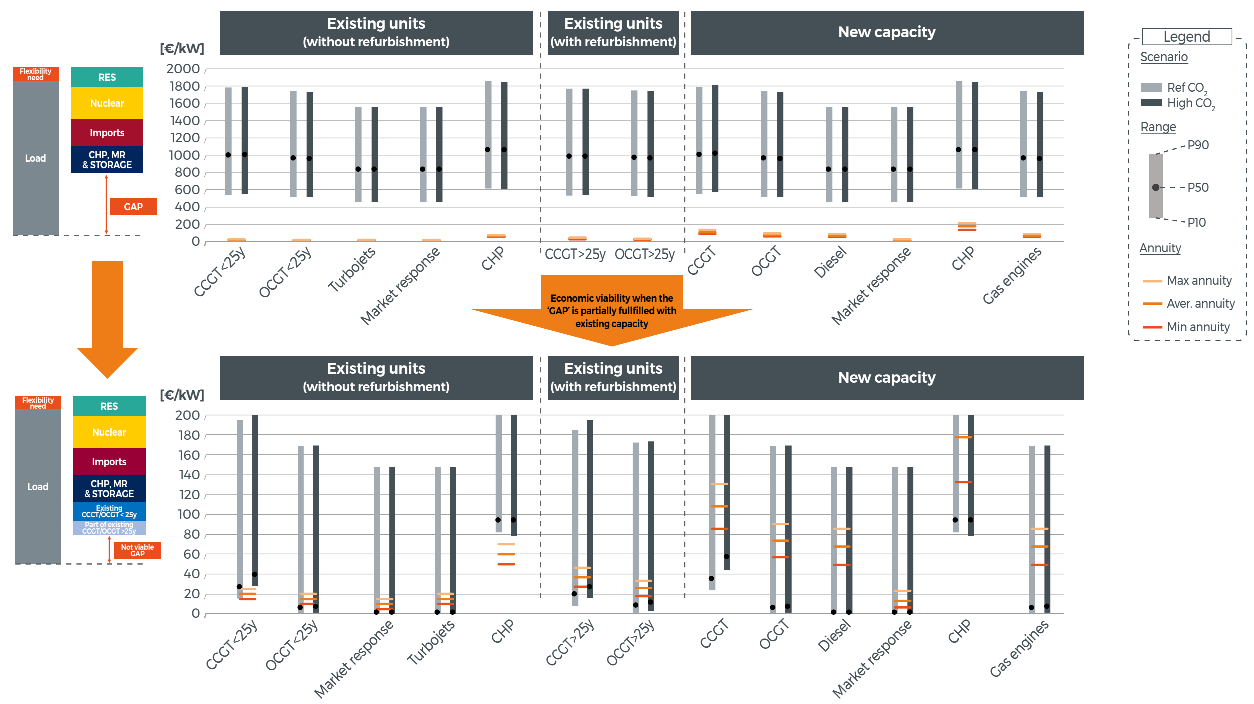
As described in Section 3.2.1, the starting point for the economic viability check is set up by taking into account the generation and storage facilities, imports and market response as defined in the 'CENTRAL' scenario. The inframarginal rents for each existing and new technology is quantified and assessed against their associated annuity. The results obtained for the 2025 'CENTRAL' scenario ('EU-BASE') are summarised in the upper part of Figure 4-15.

On this basis, additional existing or new capacity is added iteratively following the process described in Section 3.2.1. The whole process and results obtained at each step for the 2025 'CENTRAL' scenario ('EU-BASE') are described in Appendix H.1.

This process is stopped when there is no more existing or new viable capacity. The results obtained at the end of the process for the 2025 'CENTRAL'/'EU-BASE' scenario are summarised in the lower part of Figure 4-15. For this scenario, only recent existing CCGT and OCGT units (i.e. < 25 years) complemented with a part of the older existing CCGT and OCGT production fleet (i.e. > 25 years with refurbishment needed) is viable.

Based on those results, it can be stated that the equilibrium found with the 'not-viable GAP' is fragile as adding capacity to the market (without any intervention implying additional support) in order to meet adequacy requirements would make part of the capacity in the market not viable anymore. This effect can directly be seen in the results in Appendix F.2 where the 'not-viable GAP' is filled with different capacity mixes.

INFRAMARGINAL RENT FOR EXISTING AND NEW CAPACITY IN THE 'CENTRAL' 2025 SCENARIO - 'EU-BASE' [FIGURE 4-15]



More detailed results are available in Appendix H.1.

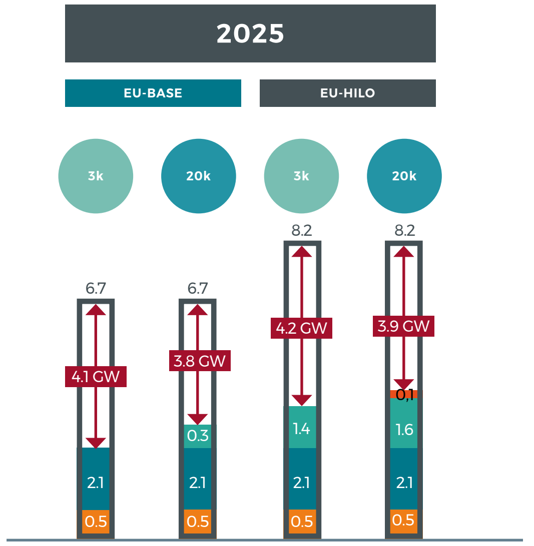
4.2.3. Sensitivity with a higher market price cap

In order to quantify the effect of an increased price cap on the economic viability results, a sensitivity was performed on the year 2025 for both the 'EU-BASE' and 'EU-HiLo' scenarios. Whereas the price cap in the simulations is typically set to 3k€/MWh for all countries, in this sensitivity it is increased to **20k€/MWh** for all simulated countries in order to reflect a value in the order of magnitude of typical Value of Lost Load (VoLL) estimates.

The increased price cap has a positive impact on market revenues and results in more capacity being economically viable 'in-the-market' (+300 MW). However, its effect remains insufficient to cover the entire identified 'GAP volume', which results in a substantial 'not-viable GAP'.

This can be explained by the fact that the price cap increase is only affecting the 'Monte Carlo' years for which this cap is actually reached. Given that there are only a limited number of hours during which the price cap is reached and that those hours are concentrated in a limited number of 'Monte Carlo' years, the average market revenues are only slightly increasing. On the other hand, the volatility of revenues is increasing with some very profitable years for the capacity holders although those are impossible to predict as they are more and more linked to weather conditions (cold waves, ...).

ECONOMIC VIABILITY CHECK (ON ENERGY MARKET REVENUES) WITH A HIGHER PRICE CAP FOR 2025 [FIGURE 4-16]



4.2.4. Sensitivity with additional 'in-the-market' capacity

Existing capacity without refurbishment costs is highly likely to remain in the market even if additional capacity would enter the market hence decreasing their revenues.

The performed economic viability check assumes certain CAPEX/OPEX and FOM costs for each technology. The 'economic viability check' results presented in previous sections might change if investors have access to privileged contracts or have other benefits in investing in new capacity. See also Section 3.2.2.

In order to illustrate the impact of additional capacity that would enter the Belgian market, a sensitivity was performed for the year 2025 on the 'EU-BASE' and 'EU-HiLo' scenarios. In order to take the most impactful case (a technology that has a relatively low marginal cost and therefore impacts the inframarginal rent of the remaining technologies), the simulations were performed by adding new efficient CCGTs by block of 1 GW. The conclusions are also valid when adding other technologies with lower marginal costs than a new CCGT.

Results from the analysis show that in both scenarios:

- The viable refurbished capacity identified in the 'EU-HiLo' scenario is no longer viable after adding 2 GW of such additional capacity in the market;
- The existing capacity that does not require refurbishment costs remains viable when adding additional capacity to the market;
- In both scenarios, the amount of capacity that would be needed to be maintained 'out-of-market' is also shown. This capacity is needed to comply with the adequacy criteria of Belgium;
- It results that the new capacity needed decreases by the same amount as the capacity that is added to the market. The existing capacity that is no longer viable 'in-the-market' is simply shifted to 'out-of-market'. In addition, the needed 'GAP volume' is decreased in line with the same amount of the added capacity (if 100% available);
- It should be noted that under such assumptions, and particularly in the 'EU-HiLo' scenario, large volumes are to be maintained 'out-of-market'. 1.6 GW would be needed 'out-of-market' (EU-HiLo) when 4 GW of new (assumed economically viable) CCGTs would be added 'in-the-market'. The volume of 'out-of-market' capacity increases when less new capacity is added 'in-the-market'. Additionally, new volumes of out-of-market capacity would be needed as there is not sufficient existing capacity leaving the market to remain adequate. For instance, when 2 GW of new (assumed economically viable) CCGTs would be added 'in-the-market', in a 'EU-HiLo' scenario there would still be a need for 3.6 GW 'out-of-market' capacity. Of the 3.6 GW, only 1.7 GW could be filled with existing capacity (that would have been pushed out of the market) whilst there would also be a need for 1.9 GW of 'new' 'out-of-market' capacity.

The results are summarised in Figure 4-17.

ECONOMIC VIABILITY CHECK OF EXISTING AND NEW CAPACITY WHEN ADDING CAPACITY TO THE BELGIAN MARKET (WITH MARGINAL PRICE LOWER OR EQUAL TO AN EFFICIENT CCGT) FOR 2025 [FIGURE 4-17]

4.2.5. LOLE and EENS after viability check

The results from the economic viability check are presented in Figure 4-18. In addition to the volume found as 'viable' 'in-the-market', the LOLE, LOLE95, EENS and EENS95 in the situation when only the 'economically viable' capacity in the market would remain are indicated. Those are called 'market LOLE' or 'market EENS' (the average number of hours per year (or amount of energy not served per year during which) the market would clear at the price cap prior to any intervention of 'out-of-market' capacity).

The volume to be found 'out of the market' is also mentioned with an indication on the new capacity to be found (assuming all existing units would remain in the future and could be contracted 'out-of-market').

Results highlight that there is still a large volume to be found 'out of the market' of which more than half is new capacity.

'GAP VOLUME', 'NOT-VIABLE GAP' AND RESULTING MARKET LOLE AND MARKET EENS [FIGURE 4-18]

		Unit	2025		2028		2030	
			'EU-BASE'	'EU-HiLo'	'EU-BASE'	"EU-HiLo'	'EU-BASE'	'EU-HiLo'
Adequacy requirement	'GAP volume'	[GW]	6.7	8.2	5.3	6.8	7.5	8.5
In the market	Viable capacity	[GW]	2.6	4	2.9	4	5.8	6.8
	(of which new capacity)	[GW]	0	0	0	0	1.5	2.5
	Remaining market LOLE	[h]	9.4	10.5	6	6.9	6	6.2
	Remaining market LOLE95	[h]	89	84	63	76	43	51
	Remaining market EENS	[GWh]	23	21.3	13.2	14	6.5	6.3
	Remaining market EENS95	[GWh]	212	176	151	177	60	57.7
Out of the market	'Remaining 'not-viable GAP'	[GW]	4.1	4.2	2.4	2.8	1.7	1.7
	(of which new capacity if all existing remains)	[GW]	2.4	3.9	1	2.5	1.7	1.7

4.2.6. Scenarios to fill the 'not-viable GAP'

In order to assess the flexibility means and perform the economic analysis, several settings were defined. Those are based on the 'CENTRAL' scenario for Belgium. The 'GAP volume' in the 'EU-BASE' and 'EU-HiLo' scenarios will be filled with existing and new capacity.

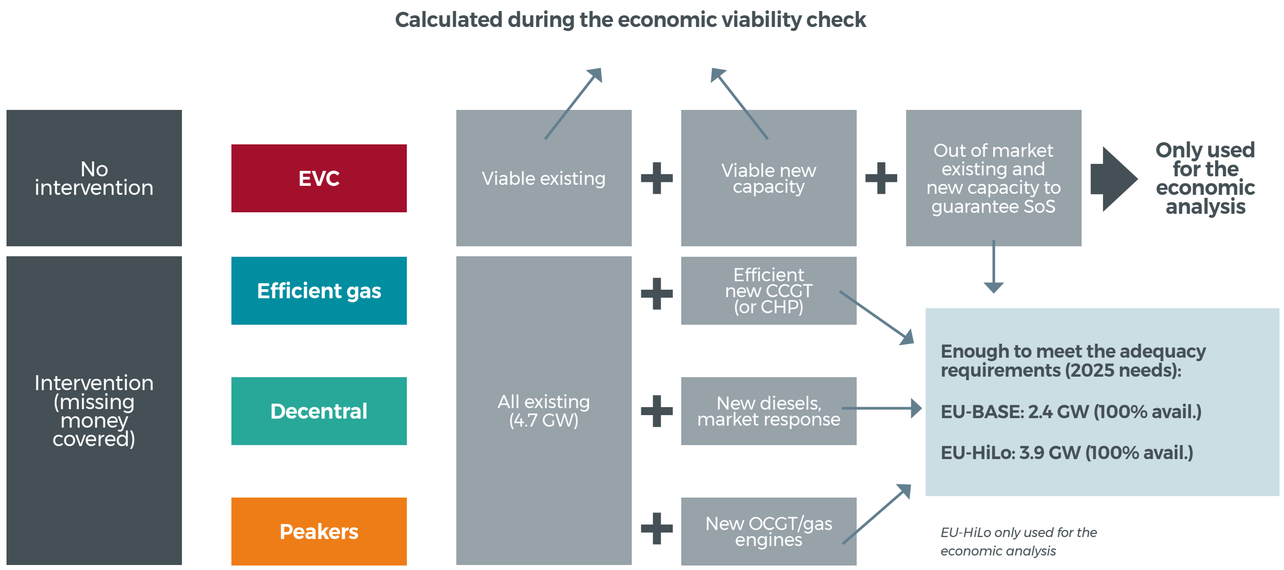
The 'without intervention' scenario called **'EVC+SR'** is defined as the viable capacity 'in-the-market' found after the 'economic viability check' (see Section 3.2.1). The 'in-the-market' viable capacity will be complemented with 'out-of-market' capacity (existing and new) in order to guarantee the adequacy criteria of the country.

The other scenarios are assuming a certain intervention 'in-the-market' allowing capacity to cover their 'missing money' in the market. In all those scenarios, all existing units are always assumed as 'in-the-market'. Such an assumption was made because the 'missing money' of extending the lifetime of existing units should be lower than investing in new capacity. Three different settings to fill the need for new capacity are considered in order to reflect investments in different technologies:

- **'Efficient gas'**: new CCGT (or CHP). For the economic assessment a sensitivity will be analysed with additional CHP for 1 GW (the rest of the need being complemented with new CCGT);
- **'Decentral'**: low CAPEX/high variable cost (activation price) technologies (diesels or market response shedding). For the simulations, only diesels were assumed although the conclusions are valid for market response and alike;
- **'Peakers'**: peaking units such as OCGT or gas engines. For the simulations, only OCGTs were assumed although the conclusions are valid for gas engines and alike;

It is important to mention that filling the needed capacity with different technologies will require the installation of more than the 100% available capacity identified in the 'GAP volume' to account for outages, energy/activation constraints, etc.

SCENARIOS TO FILL THE 'NOT-VIABLE GAP' AND USED IN THE ECONOMIC AND FLEXIBILITY ANALYSIS [FIGURE 4-19]



4.3. Flexibility needs

Section 4.3.1 discusses the general flexibility needs. These results will be compared with the available flexibility means in Section 4.4. The flexibility needs which are taken into account in the adequacy simulations, i.e. the needs during periods with scarcity risk, are presented in Section 4.3.2.

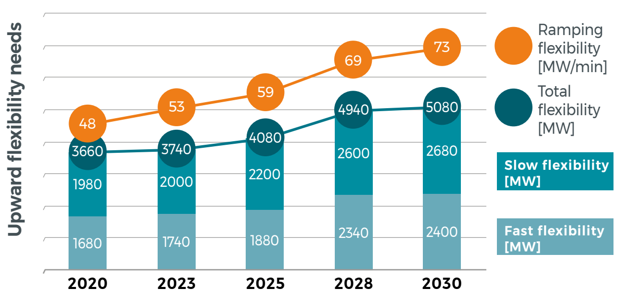
Section 4.3.3 presents a detailed analysis of the prediction risk and outage risk and their impact on the results, while 4.3.4 presents the relevant sensitivities on the 'CENTRAL' scenario. Section 4.3.5 summarises the findings.

4.3.1. Flexibility needs during all periods

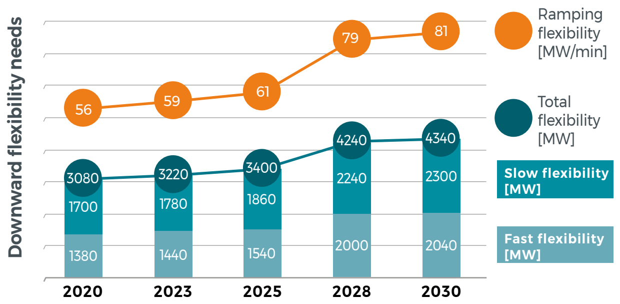
Figure 4-20 and Figure 4-21 show that **the flexibility needs will increase towards 2030**. It shows the total up- and downward flexibility needs towards 2030 increase to 5080 MW (up) and 4340 MW (down), respectively. Of this, 2400 MW (up) and 2040 MW (down) has to be fast flexibility and 1100 MW (up) and 1220 MW (down) has to be ramping flexibility, or 73 MW/min (up) and 81 MW/min (down), if expressed per minute. The slow flexibility needs can be derived by the difference between the total and fast flexibility, i.e. 2680 MW (up) and 2300 MW (down).

Note that the results present a case in which the nuclear generation units are assumed to be replaced by larger units of 600 – 800 MW. The results of a sensitivity when nuclear capacity is replaced by small units of 100 - 200 MW are represented in Annex G. As the effect on this sensitivity remains below 100 MW (decreasing the total and fast needs) and hence doesn't affect the conclusions, this sensitivity is not discussed in detail.

UPWARD FLEXIBILITY NEEDS BETWEEN 2020 AND 2030 IN THE CENTRAL SCENARIO [FIGURE 4-20]



DOWNWARD FLEXIBILITY NEEDS BETWEEN 2020 AND 2030 IN THE CENTRAL SCENARIO [FIGURE 4-21]



The increasing trend in flexibility needs is mainly explained by the increasing forecast risks caused by additional variable renewable generation capacity. Two periods can be distinguished:

- **Period 2020 - 2025**

  The slight increase during the first period is explained by an increasing capacity of onshore wind power and photovoltaics. This volume increase is stable and fairly moderate because the increase in prediction errors remains relatively low due to their geographically dispersed nature. Furthermore, the increase in flexibility needs is partially offset by expected forecast tool improvements. Finally, the nuclear phase-out between 2020 and 2025 slightly reduces the forced outage risk due to the decommissioning of several 1 GW nuclear generation units (particularly for the slow and fast flexibility needs).

  The up- and downward **ramping flexibility** needs gradually increase from 48 MW/min in 2020 towards 59 MW/min in 2025 for upward flexibility, whilst the downward needs increase from 56 MW/min MW in 2020 to 61 MW/min MW in 2025. This is only driven by the increase of the prediction risk following increasing variable generation.

  In general, the up- and downward **fast flexibility** needs follow the same trend: they increase from 1680 MW in 2020 to 1880 MW in 2025 for upward flexibility, and from 1380 MW in 2020 to 1540 MW in 2025 for downward flexibility. Note that the upward needs are higher as the downward flexibility needs, which is mainly explained by the forced outage risk being higher for the upward flexibility needs.

  The same explanation is valid for the evolutions of the up- and downward **total flexibility** needs, represented by the total flexibility needs: from 3660 MW in 2020 to 4080 MW in 2025 on the upward side, and from 3080 MW in 2020 to 3400 MW in 2025 on the downward side.

- **Period 2025 - 2030**

  After 2025, a strong increase of all flexibility needs is observed representing 73 MW/min (81 MW/min), 2400 MW (2040 MW) and 5080 MW (4340 MW) for upward (downward) ramping, fast and total flexibility needs respectively. This increase is mainly due to the foreseen increase in offshore wind power. The effect on the prediction risk is significant as prediction errors of offshore wind are higher than for other renewable technologies, particularly due to the geographical concentration. Note that the installed capacity of photovoltaics and onshore wind is also assumed to increase, affecting the flexibility needs, although to a lesser extent.

It is clear that an increase of flexibility needs is inevitable following the transition towards a renewable energy system. Flexibility needs can be managed by increasing improvements of forecast tools, while keeping outage risks low, wherever possible. Furthermore, it should be investigated if there are technology solutions for offshore wind parks which can mitigate the impact of the variability of offshore wind power.

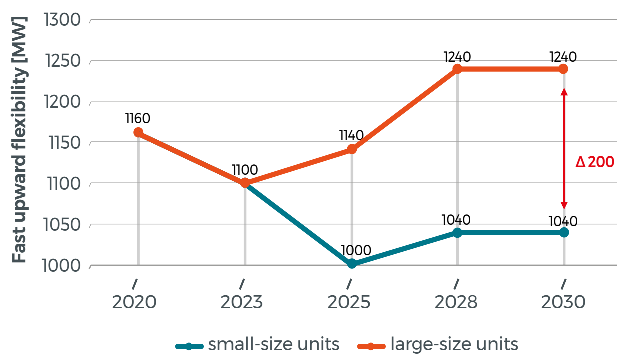
4.3.2. Flexibility needs during periods with scarcity risks

It is explained in Section 3.4.3.1 that altough flexibility needs are lower during periods with scarcity risk (lower variable generation hence lower prediction risks), it remains important to take flexibility needs into account in the adequacy assessment. These needs should cover the risks which may occur in scarcity periods, i.e. to deal with the forced outage of a power plant or transmission asset (i.e. NEMO-Link), and relevant prediction risks of renewable energy.

Figure 4-22 represents the upward fast flexibility needs which are integrated as margins in the adequacy assessment. In practice, this means that part of the capacity of generation units and other capacity is reserved from the day-ahead market simulations, and kept available for balancing / flexibility purposes. This capacity has to dispose of fast flexibility characteristics (activation in 15 minutes).

- Between 2020 and 2025, fast upward flexibility needs are reduced from 1160 MW to 1000 MW following a reduction of the forced outage risk when replacing the nuclear generation units with small-size units. Note that a minimum requirement of 1000 MW is set by the dimensioning incident of NEMO-Link. When replaced by large-size units, instead of small units, the fast upward flexibility needs remain stable compared to 2020, i.e. at 1140 MW.
- After 2025, the fast upward flexibility needs increase due to the integration of additional renewable generation, and in particular the commissioning of the second wave of offshore wind generation. The needs with small-size units increase to 1040 MW and 1240 MW when assuming large-size units.

MINIMIM UPWARD FAST FLEXIBILITY NEEDS DURING PERIODS WITH SCARCITY RISK IN THE 'CENTRAL' SCENARIO [FIGURE 4-22]



4.3.3. Analysis of drivers of flexibility

The above-mentioned results are calculated based on a convolution of the forced outage risk and the prediction risk. This section contains a few analyses to better understand the impact of these drivers on the flexibility needs. The prediction risk is elaborated in more detail by analysing the behaviour of the residual load (i.e. its yearly profile, its variations and the forecast errors and duration).

4.3.3.1. FORCED OUTAGE RISKS

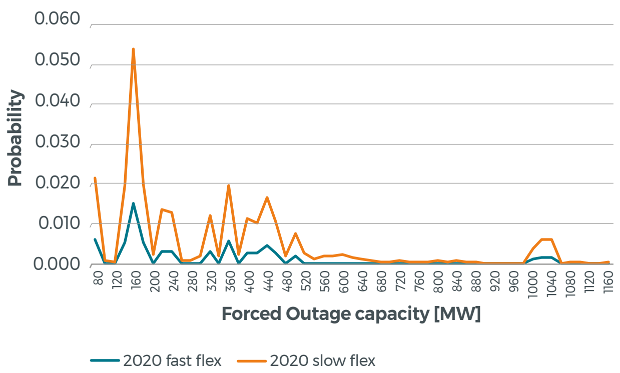
The forced outages of generating units are modelled by means of a Monte Carlo simulation. This determines the forced outage risk represented by a probability distribution curve representing the probability of losing a certain capacity during a certain period. Different Monte Carlo simulations are conducted for:

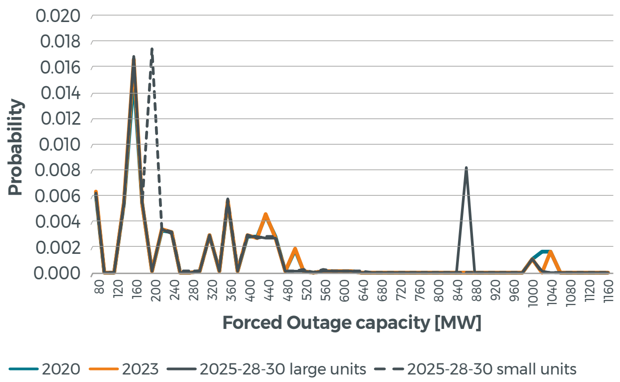
- 2020 based on the existing capacity mix, 2023 taking into account the phase out of the first nuclear generation units, 2025-30 taking into account the full nuclear phase out and the replacement by new capacity;
- small-size versus large-size units assumed to replace the nuclear generation units as from 2025;
- fast and slow flexibility distinguished by the duration of a forced outage, increasing the forced outage risk by having a higher probability of simultaenous forced outage events.

Figure 4-23 (left) shows the forced outage distribution of power plants in 2020. The distribution for the slow flexibility shows exactly the same profile as with fast flexibility, but only with higher probabilities. Besides the order of magnitude, both curves show an identical behavior.

When comparing the forced outage distribution for fast flexibility for the different time horizons in Figure 4-23 (right), the effect of the nuclear phase out in 2023 and 2025 can be seen. The probability of a forced outage capacity around 1000 MW is reduced towards 2025 (only the NEMO-Link outage risk prevails in this order of magnitude), and an increased probability of occurrence around the force outage capacity of 800 MW and 200 MW is observed. This follows the replacement by alternative capacity (small- and large-size units) as from 2025. The effect on the downward side (forced outages up to 1000 MW when losing NEMO-Link in export mode is not demonstrated graphically as this remains identical over all time horizons. Note that if new units larger than 1 GW (or at least when a risk exists of losing more 1 GW due than to a forced outage) would be installed, the forced outage risk and the capacity of the dimensioning incident will increase.

FORCED OUTAGE PROBABILITY FOR FAST AND SLOW FLEXIBILITY IN (LEFT) AND FOR FAST FLEXIBILITY FOR DIFFERENT TIME HORIZONS 2020 – 2030 (RIGHT) [FIGURE 4-23]





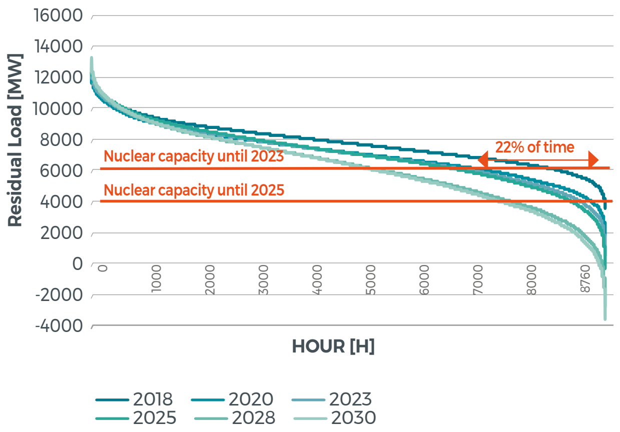
4.3.3.2. PREDICTION RISKS (AND RESIDUAL LOAD VARIATIONS)

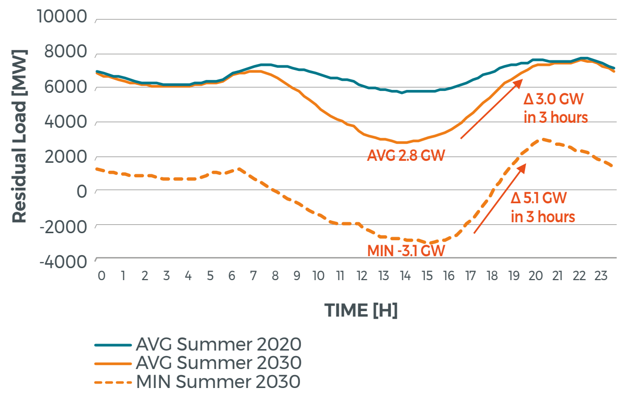
Residual load variations

Residual load variations, as defined in Section 3.4.2.1, are one of the main drivers of the flexibility needs. Figure 4-24 (left) shows that periods with negative residual load occur (more frequently, and more negatively towards 2030). This might result in periods with **excess energy**, sometimes even characterised with negative prices when facing limited downward flexibility in the system. The real effective system impact of excess energy depends on the availability of local downward flexibility in the market, export capabilities and the reduction of renewable generation.

Figure 4-24 (right) shows that nuclear generation, which is typically seen as rather inflexible (although some output reductions are proven to be possible under certain conditions) can result in excess energy for up to 22% of the time in 2020. Again, the impact on the system depends on the system conditions.

RESIDUAL LOAD DURATION CURVE (LEFT) AND AVERAGE DAILY RESIDUAL LOAD PROFILE DURING SUMMER (RIGHT) [FIGURE 4-24]





Hence, most problems will be avoided when having sufficient export capabilities at these moments (although historic events have shown that this is rather a regional phenomenon). Furthermore, there is also the possibility of renewable capacity reductions at such moments (at least the individually controlled wind power plants which can voluntary reduce their output based on negative prices). Finally, practice also shows that some of the nuclear generation units can temporarily reduce their output level, under specific technical constraints. As such, these events provide incentives for storage technologies and other technologies that are able to cope with excess energy well. Consequently, Elia does not yet foresee technical issues as long as adequate price signals incentivise market players to react accordingly and all large wind parks actively participate in the market (day-ahead, intra-day and balancing).

In summer months, a typical phenomenon is expected to be observed referred to as the '**duck curve**'. This is characterised by a residual load profile representing a minimum residual load during the day due to solar power, and a ramp up of the residual load towards the evening peak due to sundown. Figure 4-24 (right) already shows the average daily residual load in Belgium in 2020 and 2030 during summer. In 2030, the minimum of this profile is found to be a 2.8 GW during day time (which may even become extremely negative in some cases) while this profile faces a ramp at a rate of 3 GW between 17h and 20h. In the lowest residual demand, the minimum goes down to -3.1 GW and the 3 hour ramp can even amount to 5.1 GW.

An extreme case is represented in Figure 4-25 and is based on a day in June with abundant wind power and solar power generation. This day shows a local surplus of almost 3 GW, as a morning ramp down of 3 GW in 3 hours and an evening ramp up of 4 GW in 3 hours.

ILLUSTRATION OF RESIDUAL LOAD IN 2020 AND 2030 (LEFT) AND CORRESPONDING RENEWABLE AND MUST RUN GENERATION (RIGHT) IN 2030, BASED ON WIND, PV, LOAD AND MUST RUN PROFILES OF JUNE 7, 2017 [FIGURE 4-25]

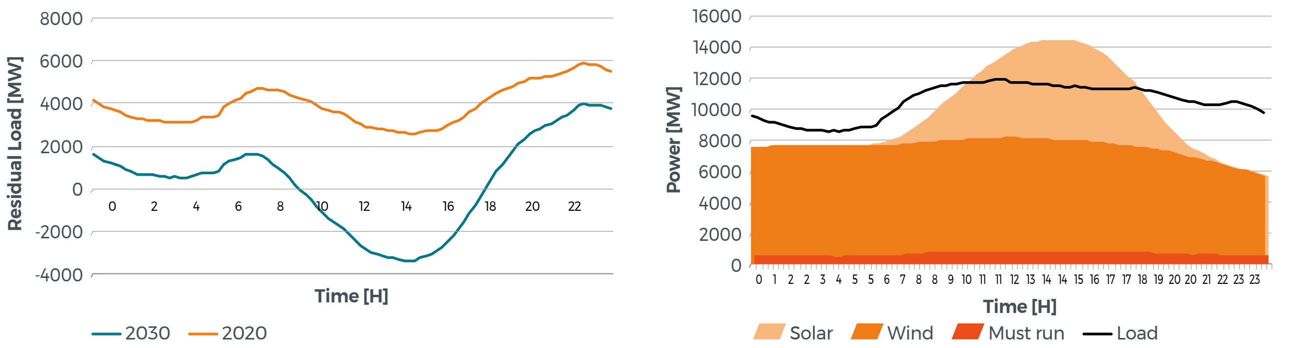


Figure 4-26 represents the residual load variations over 15 and 60 minutes. These show a trend to increase towards 2030. Table 2 shows that 15 min variations of 472 MW and 60 min variations of almost 1679 MW may happen rather frequently (1% of the time in 2030), whilst on some rare occasions (0.1% of time) these values may exceed 853 MW (15 min variations) and 2124 MW (60 min variations). Part of these ramping requirements will be covered by means of the ramping, fast and slow flexibility and another part by the day-ahead market depending on the predictability of these variations.

PROBABILITY DISTRIBUTION OF THE RESIDUAL LOAD VARIATIONS OVER 15 MINUTES AND 60 MINUTES [FIGURE 4-26]

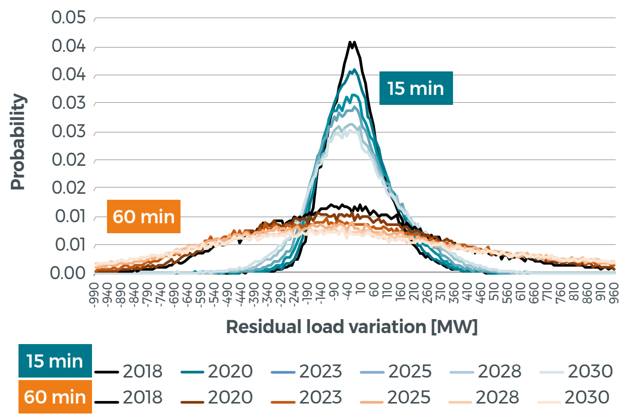


TABLE 2: RESIDUAL LOAD VARIATIONS: MEAN ABSOLUTE ERROR [MAE] AND PERCENTILLES [P90.0, P99.0 AND P99.9]

(MW)	15 MINUTE VARIATIONS					60 MINUTE VARIATIONS				
	2020	2023	2025	2028	2030	2020	2023	2025	2028	2030
MAE	96	107	115	130	138	331	377	413	471	503
P90.0	194	214	234	269	290	677	768	854	993	1075
P99.0	353	366	386	440	472	1132	1207	1310	1546	1679
P99.9	654	664	681	839	853	1466	1523	1661	1967	2124

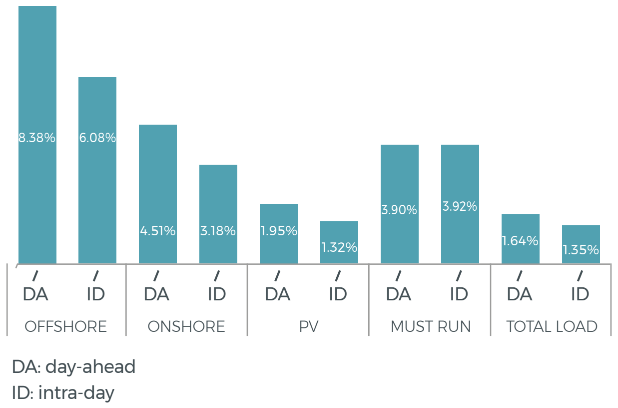
Forecast errors and variability

Unexpected variations of the total load, wind power and photovoltaic are one of the two drivers for the flexibility needs. Accurate forecast tools used by market parties are therefore indispensable to manage the flexibility needs of a system. Figure 4-27 represents the Mean Absolute Error (MAE) for each forecast over 2017-2018. The MAE is the main indicator used for forecast accuracy and is expressed as a percentage of the installed capacity.

For most forecasts, one can see that the day-ahead forecast error is clearly larger than the last intra-day forecast error. This is explained as predictions are generally more reliable when approaching real-time. This is most pronounced for the wind power forecasts, and less pronounced for the forecasts of the decentral 'must run' units. The results show that on average photovoltaic predictions are more accurate than wind power predictions (which do not exclude the occurrence of extreme events), while onshore predictions are more accurate than offshore predictions. The decentral 'must run' generation obtains more or less the same forecast accuracy as onshore wind.

The differences in forecast accuracy between technologies is partially explained by smoothing due to geographical spread over the country, which is not the case for offshore wind power. This has to be carefully investigated, as offshore wind power is therefore more sensitive to large forecasting errors, certainly when taking into account an increase of offshore wind power capacity which is heading towards 4.0 GW. Elia has already taken initiatives to improve offshore wind predictability in the framework of the completion of the first wave of offshore wind generation of 2.3 GW (and in particular in the predictability of storm cut-outs and fast ramps). Elia will therefore investigate possible solutions to mitigate the impact on the flexibility needs, including the option to have certain technology requirements (e.g. capabilities to reduce the impact of storm cut-out and cut-in, preventive curtailment and ramping limitations) on new offshore wind parks.

MEAN ABSOLUTE ERROR (EXPRESSED AS PERCENTAGE OF INSTALLED CAPACITY) OF THE DIFFERENT FORECASTS TOOLS [FIGURE 4-27]



DA: day-ahead
ID: intra-day

This lower forecast accuracy in day-ahead explains higher slower flexibility needs rather than fast flexibility needs. Crucially, there has to be sufficient trading possibilities for market players to deal with these intra-day forecast updates. In terms of flexibility, these are all aggregated resulting in three distribution curves for the slow, fast and ramping flexibility.

Results show that offshore generation may lead to very large flexibility needs for exceptional situations. The offshore integration study [ELI-17] has already shown that large variations (ramps) due to wind power variations or storms (due to a cut-off and cut-in of large units) may occur over 15 and 60 minutes. The study concluded that in 2020, when 2.3 GW of offshore wind power is installed:

- in most realistic scenarios the power loss caused by a storm event often goes beyond 1000 MW (over the duration of the storm) while a severe storm might even cause a power deviation of more than 2000 MW ;
- deviations around 1000 MW can happen in both directions (up and down) within 30 minutes when looking at the maximal ramps observed in both cut out and cut in phases during a storm event;
- power variations (which are not necessarily due to storm) of 150 MW within 15 minutes are expected to happen around 3 % of the time.

These effects will be further amplified when commissioning a second wave of offshore wind generation increasing total capacity from 2.3 GW to 4.0 GW. A simple extrapolation of the current forecast errors is probably conservative as the second wave will be installed at some distance from the first. Indeed, storms and wind power variations may not affect the two locations at exactly the same time, resulting in a smoothing of the variations.

However, without having further data at this stage, only the general forecast improvements of the study are taken into account. Furthermore, potential technological capabilities to deal with storm, ramps and forecast errors are not further investigated. A detailed analysis of these effects requires new forecast data for this specific location and a detailed analysis of the system integration of the second wind park. This is out of the scope as this would require new forecast data and analyses. In order to take some of these smoothing effects into consideration, the effect of the yearly 1% forecast improvement is accounted when extrapolating the forecast errors to the future capacity installed. Note that Elia already foresees an improvement of the predictions of such extreme events due to the implementation of a new forecast tool.

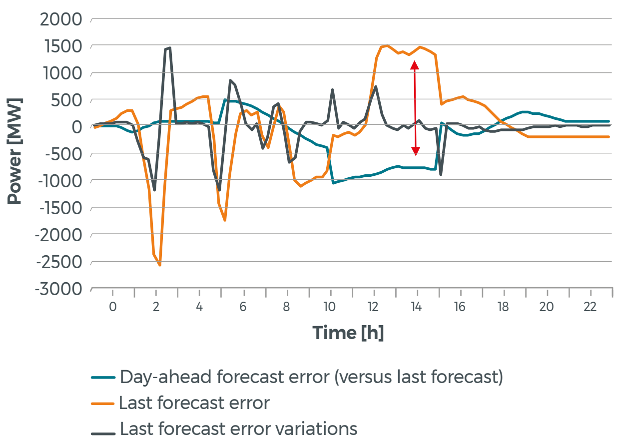
Being mindful of the above-mentioned assumptions, Table 3 shows how the day-ahead (intra-day) prediction errors of 1985 – 2009 MW (1484 - 1624 MW) may be possible as well as 15 (60) minute variations of 869 – 915 MW (2007 – 2152 MW). Even when taking the additional forecast improvements into account during extreme events and extra geographical smoothing which may impact the extrapolation to 2030, the figures show that the integration of additional wind power should be analyzed carefully.

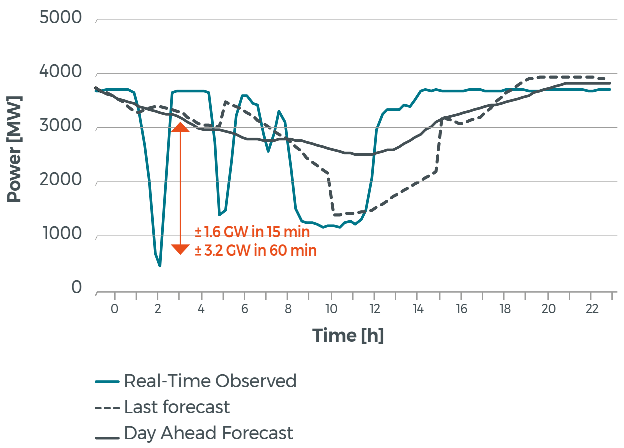
TABLE 3: OFFSHORE FORECAST ERRORS AND VARIATIONS OF THE OFFSHORE WIND TOWARDS 2028-30

2030	DAY-AHEAD FORECAST ERROR	LAST INTRA-DAY FORECAST ERROR	PRODUCTION VARIATION 15 MIN	PRODUCTION VARIATION 60 MIN
Average	-32	-11	0	0
Standard deviation	431	319	137	356
Percentile 99,0	-1272	-934	-403	-1045
Percentile 99,9	-1985	-1624	-915	-2007
Percentile 1,0	1180	891	415	1090
Percentile 0,1	2009	1484	869	2152

Figure 4-28 shows the extrapolation for the storm of January 3, 2018 towards 2030 in which one can witness a cut-out and cut-in larger than 1.6 GW in 15 minutes, and even 3.2 GW in 60 minutes. Furthermore, this drop was not predicted in day-ahead, and predicted too late with the intra-day forecasts. It can also be seen that the intra-day forecasts correct the power predictions downwards, while with even more wind power as day-ahead occurred.

EXTRAPOLATION OF THE STORM EVENT ON JANUARY 3, 2018 TOWARDS 2030 [FIGURE 4-28]



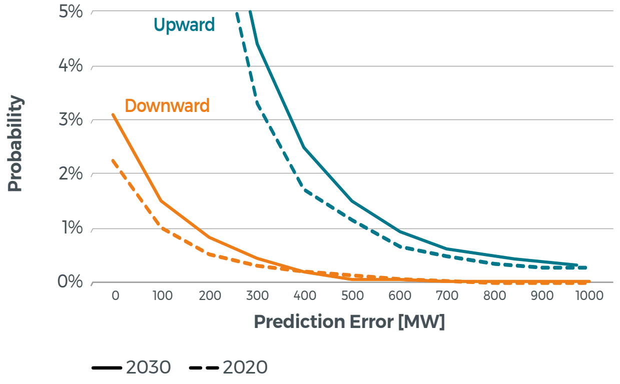


Duration

As some fast flexibility providers may face constraints in terms of the duration of the up- or downward flexibility, and slow flexibility providers may require an activation time of at least 5 hours, it is important to check the maximum duration of the forecast errors related to the forecast error. Figure 4-29 shows the probability that the intra-day residual load forecast error of a certain capacity lasts 5 hours or longer in 2020 and 2030.

It is shown that the probability to lose more than 1000 MW remains below 1% of the time, even in 2030. However, the 1000 MW threshold is important as forced outage duration of power plants or transmission assets can take up to 5 hours or longer and therefore needs to count on slow flexibility and the day-ahead market for re-scheduling. This means 1000 MW of the fast flexibility should ideally be delivered with capacity facing no limitation in terms of duration, by means of technology or by means of aggregation.

PROBABILITY THAT THE RESIDUAL LOAD PREDICTION ERROR (LAST FORECAST) OF THE LAST FORECAST HAS A DURATION OF UP TO 5 HOURS OR MORE [FIGURE 4-29]



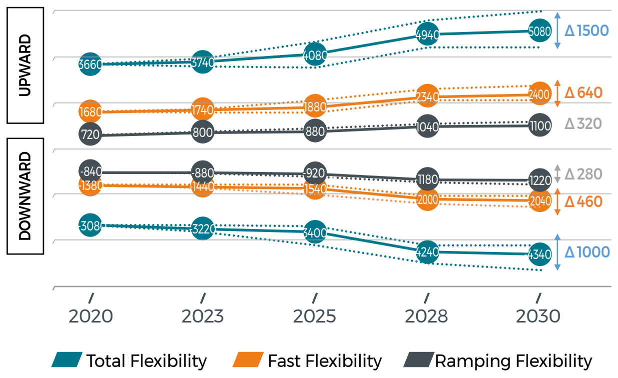
4.3.4. Sensitivities

Three sensitivities (as defined in Section 2) are conducted on the 'CENTRAL' scenario:

- A sensitivity with a 2 GW nuclear capacity prolongation ('N-PRO'). This will impact the forced outage risk;
- A sensitivity with lower and higher renewable capacity installed. This will impact the prediction risk;
- A sensitivity with the 'IHS-Markit' and 'low demand'. This impacts the prediction risk (although it will have no impact during the periods without scarcity risk).

Note that every sensitivity is making a distinction between large- and small-size units. All results are depicted in Annex G. It shows that the nuclear prolongation and the sensitivities on the demand have negligible effect on the results. This is in contrast to the renewable capacity sensitivities which are shown in Figure 4-30 for the case where large-size units replace the nuclear generation. One can see that the impact is around 1000 – 1500 MW for total flexibility, around 450 – 650 MW for fast flexibility and around 300 MW for ramping flexibility.

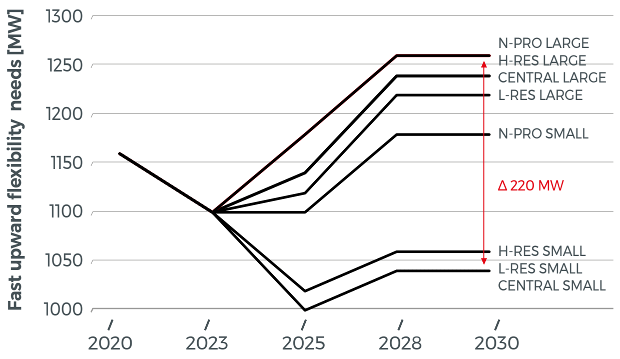
SENSITIVITY ON THE FLEXIBILITY NEEDS FOR 'HIGH RES' - 'LOW RES' COMPARED TO 'CENTRAL' SCENARIO [FIGURE 4-30]



When assessing the flexibility needs during the periods with scarcity risk it was found that the nuclear capacity prolongation and high / low renewable capacity impacts the result (Figure 4-31). The fast upward flexibility in 2030 varies with 220 MW :

- 1260 MW when facing a nuclear capacity prolongation where the remaining capacity is replaced by large size units;
- 1040 MW in the 'CENTRAL' scenario (or the sensitivity with low RES) where the remaining capacity is replaced by small-size units.

SENSITIVITIES ON THE FAST UPWARD FLEXIBILITY NEEDS IN PERIODS WITH A RISK OF SCARCITY [FIGURE 4-31]



4.3.5. Summary of findings

Results show that **flexibility needs will increase towards 2030** following the integration of variable renewable capacity such as wind power and photovoltaics, even when taking into account future forecast accuracy improvements. The new offshore wind power capacity which will grow to 4 GW after 2025 is an important driver for increasing needs towards 2030. Elia already publishes real-time forecasts and is currently implementing specific offshore forecast tools to better predict offshore storm cut-outs and wind power variations in order to help the market. However, future prediction accuracy improvements will not offset the effect of the renewable capacity increase.

As in former adequacy studies, **Elia takes into account a margin for operational flexibility to deal with forced outages and forecast errors when calculating the adequacy needs**. The level is set by the flexibility needs calculated during periods with scarcity risk. This accounts for the dimensioning incident, i.e. the loss of a nuclear power plant until 2025, or the loss of a HVDC-interconnector to Great Britain. The impact of forecast errors is limited, but present, increasing the flexibility needs during periods with a scarcity risk to a value of 1160 MW in 2020 and evolves towards 1040 MW to 1240 MW in 2030 depending on if new capacity is characterised by small-size or large-size units. It can be concluded that the forced outage risk plays a large role and that these figures are likely to be further impacted when considering units which can result in an instantaneous loss of 1000 MW or higher.

Analysis of the residual load also reveals **increasing periods with a negative residual load** and periods with a residual load lower as the installed nuclear capacity (before the nuclear phase-out). When predicted, this situation can be covered with flexibility in the day-ahead market, i.e. by means of stopping generation units, scheduling generators at minimal power, or charging storage facilities, while exporting to other regions in Europe. But also after day-ahead, surplus forecast errors are, at least the loss of a HVDC-interconnector in export and will need to be covered (as it is expected that in situations with a low or negative residual load, Belgium will be exporting). It is estimated that such events will increase the value of technologies which can cope well with excess energy. As last resort, wind power generation can reduce its output to cope with periods of excess power. This requires adequate price signals (e.g. low or even negative prices), and the technical controllability of renewable generation through communication and control equipment.

The current balancing market with adequate price signals will ensure that flexibility needs are covered as much as possible by the market. In this way, Elia will only cover the remaining system imbalance and cover at least the dimensioning incident with contracted balancing capacity, and non-contracted reserves whenever possible, especially in a system with 4 GW of offshore wind power. While the exact effects are being investigated, It might be **considered whether technological solutions for offshore wind parks (e.g. specific ramping behavior during storms) can minimise the impact on the flexibility needs of the system.**

4.4. Flexibility means

While Section 4.3 discusses the general flexibility needs. This section compares the results with the available flexibility means.

Section 4.4.1 compares the flexibility needs with the **installed flexibility means**. This allows an analysis as to whether, under ideal circumstances, the flexibility is present in the system, or measures are needed to ensure the integration of additional flexibility capabilities in the system (e.g. by means of minimum technical requirements on new capacity).

Section 4.4.2 compares the flexibility needs with the **available operational flexibility** means for each hour of the year. This makes it possible to analyse whether the installed flexibility is also available in the intra-day and real-time, and not already used in the day-ahead market. A few sensitivities are conducted towards the evolution from 2020 to 2025 and 2030, as well as the effect of a nuclear capacity prolongation and the composition of technologies in the 'Remaining GAP'. Section 4.4.3 summarises the findings.

4.4.1. Installed flexibility

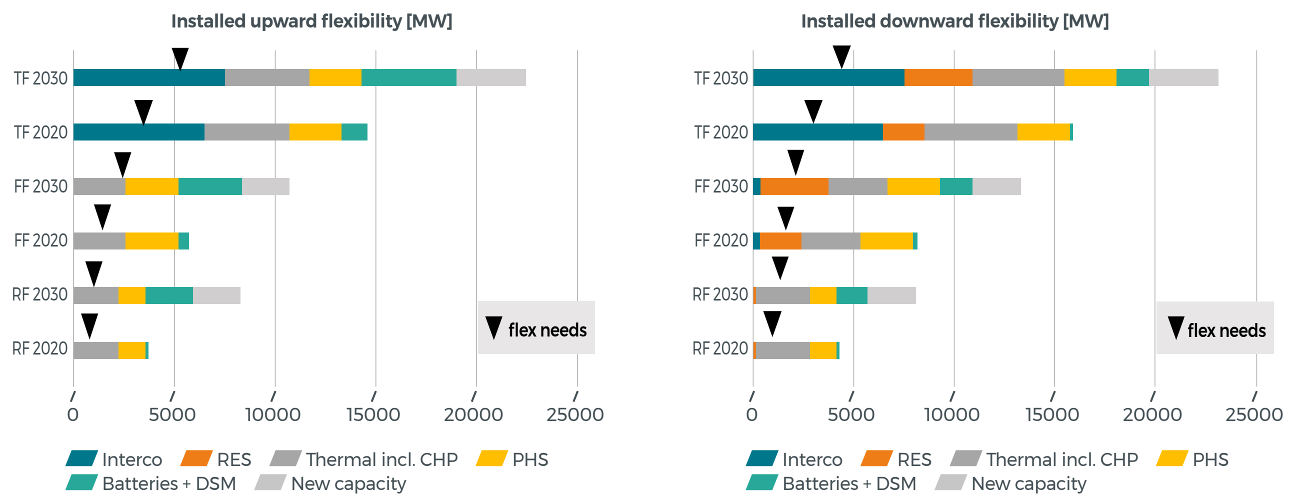
Figure 4-32 represents the flexibility installed in 2020 and 2030. This is based on the 'CENTRAL' scenario. In contrast to the next sections, an abstraction is made from the scheduling status of these units when calculating the maximum flexible capacity of each unit. The maximum flexibility which can be delivered in 1 minute (ramping flexibility), 15 minutes (fast flexibility) and 5 hours (slow flexibility) is determined for each capacity per technology type.

It takes into account the technical characteristics of each technology as specified in Section 2.8.3 (in particular the minimum stable power, rated capacity and the ramp rate). Because an abstraction is made from the dispatched production level, the results should be viewed as the maximum flexibility that could theoretically be available under ideal conditions (if not used in day-ahead markets, dispatched, full energy reservoir,...). **This installed flexibility is not to be seens as flexibility which is operationally available in the system (following maintenance or generation, storage or demand schedules) and can be activated when needed.** This is further investigated in Section 4.4.2.

Figure 4-32 shows that installed flexibility will be sufficient in 2020 and 2030 to cover the needs, irrespective of which type of capacity will replace the nuclear power plants after 2025. Indeed, the installed flexibility means (already in 2020) exceed the needs in 2030. Furthermore, note that the adequacy assessment already considers that minimum flexibility means are installed to cover the needs during periods with a scarcity risk. Consequently, the operational availability in the system of different types of flexibility means will depend more on market mechanisms than on installation requirements (Section 4.4.2).

- In 2020, the **ramping and fast flexibility** are mainly covered with thermal and pumped-hydro storage (PHS) capacity, as well as with controllable wind power capacity for downward flexibility. In 2030, this is further complemented with flexibility provided by additional distributed capacity such as battery storage, market response (only upward) and wind power (only downward), as well as the flexibility provided by new capacity to cover adequacy needs after the nuclear phase out.

INSTALLED AVAILABLE FLEXIBILITY MEANS FOR 2020 AND 2030 FOR THE 'CENTRAL' SCENARIO [FIGURE 4-32]



It should be noted that the contribution of interconnections to ramping and fast flexibility is assumed to remain limited towards 2030 (besides the reserve capacity sharing for FRR with neighbouring countries currently taken into account in Elia's reserve dimensioning). Although there will be a development of cross-border balancing markets – as required by the European Guideline on Electricity Balancing, the effect on the guaranteed flexibility is expected to be limited. This is due to periods in which the remaining cross-border interconnection capacity is low. The same logic is followed for imbalance netting which will continue to contribute in real-time to the delivery of ramping flexibility. Imbalance netting might contribute but is not guaranteed at all times as cross-border interconnection capacity needs to be available and simultaneously other countries need to have imbalance in the opposing direction to the imbalance of Belgium.

- For the **slow flexibility**, all installed capacity is assumed to contribute to upward flexibility (except for wind power and nuclear generation). This includes all the remaining interconnection capacity after day-ahead. Furthermore, this also includes the full capacity of thermal units (except when facing must run conditions such as CHP-installations) as they can be started within 5 hours. For the downward flexibility, this also includes wind power and biofuel (while excluding market response and consumption shifting).

The installed flexibility is expected to increase towards 2030 due to the integration of decentralized capacity, wind power and new capacity contributing to the adequacy needs. **Result show there are and will be sufficient flexibility installed in the system to impact of flexibility needs. Of course, this does not imply that this flexibility is operationally available when needed, as will be further discussed in Section 4.4.2.**

4.4.2. Operationally available flexibility means

4.4.2.1. 'CENTRAL' SCENARIO

The previous section demonstrates that there are always sufficient technical capabilities in the system. However another important question is whether these flexibility means are also operationally available when needed. This might not be the case if they were already fully dispatched in day-ahead, if they are not dispatched and their activation time last longer as a few hours, or when the energy storage is depleted or full.

The results for the operational available flexibility means for each hour of each of the 33 Monte Carlo simulations are represented in Figure 4-33 with key statistic indicators (average - AVG, as well as percentile - P99.0 and P99.9 - to represent the minimum availability). These values are used to check whether the flexibility needs are covered, i.e. green when the value is higher as the flexibility needs, and orange if this is not the case. Note that there is no formal reliability criterion, and that the percentiles should express the ability to cover (almost) all flexibility needs.

Figure 4-33 shows that although the average availability of all types increases, upward fast flexibility needs are never fully covered. Furthermore, shortages in available up- and downward ramping and downward fast flexibility start occurring as from 2025.

FIGURE 4-33: AVERAGE (AVG), P99.0 AND P99.9 PERCENTILE OF OPERATIONALLY AVAILABLE FLEXIBILITY MEANS IN THE 'CENTRAL' SCENARIO

MEANS [MW]		2020			2025			2030		
		AVG	P99.0	P99.9	AVG	P99.0	P99.9	AVG	P99.0	P99.9
UP	ramping	199	98	92	730	24	12	1087	18	11
	fast	1197	513	507	1825	449	442	2237	487	480
	total	8480	4831	3355	9371	5468	3227	11253	6075	1532
DOWN	ramping	1235	155	100	1501	24	17	1735	24	13
	fast	3813	2136	1453	4412	1616	1219	4943	1423	1088
	total	10622	8675	7443	11980	8642	7556	12391	8218	7473

The available flexibility means for ramping, fast and total flexibility are expressed in Figure 4-33 and Figure 4-34 as cumulative distribution functions. The flexibility needs for ramping flexibility (activated in 1 minute), fast flexibility (15 minutes) and slow/total flexibility (5 hours) are depicted on the same graph. A deviation from the available flexibility means from full availability for that capacity type will require mechanisms which allow to secure the availability of this capacity after day-ahead (i.e. with some kind of reservation by Elia or the market).

In first instance, the figures represent the ramping (expressed in MW/min), fast and slow flexibility (expressed in MW) means. It can be seen that the upward fast flexibility means is determined at 2400 MW (cfr. Section 4.3.1). This value is compared with the available flexibility means showing a degressive curve where a capacity of 2400 MW corresponds with an availability of around 55%. Such an availability level is largely insufficient and will require a mechanism ensuring the operational availability of this capacity. In contrast a volume of fast flexibility means of 400 MW is observed to be available 100% of the time.

Figure 4-34 shows that in 2030, the **available upward flexibility means** do not cover the needs and are therefore indicated by a red indicator. It is observed that the fast flexibility needs are only covered 50-60% of the time, while ramping flexibility is covered between 70% - 80% of the time. While it is confirmed in the previous section that this flexibility is expected to be installed, it will be a matter of having the right incentives or mechanisms ensuring that this capacity is secured well in advance in order to ensure availability when needed. Today, this is ensured by means of Elia's contracted balancing capacity, together with reactive balancing through imbalance settlements. The cumulative probability distribution in Figure 4-34 shows that the shortage for the ramping flexibility is relatively limited, in contrast to the fast flexibility.

Results also show that **slow or total flexibility**, both up- and downward are mainly covered when taking into account the import capabilities (indicated by a green marker). However, Figure 4-33 indicates that for upward the 99.9% percentile will not always be reached. In any case, potential shortages will be relatively small. However, it is to be noted that liquidity problems on the intra-day markets will reduce this coverage.

OPERATIONAL AVAILABILITY OF UPWARD FLEXIBILITY MEANS IN 2030 [FIGURE 4-34]

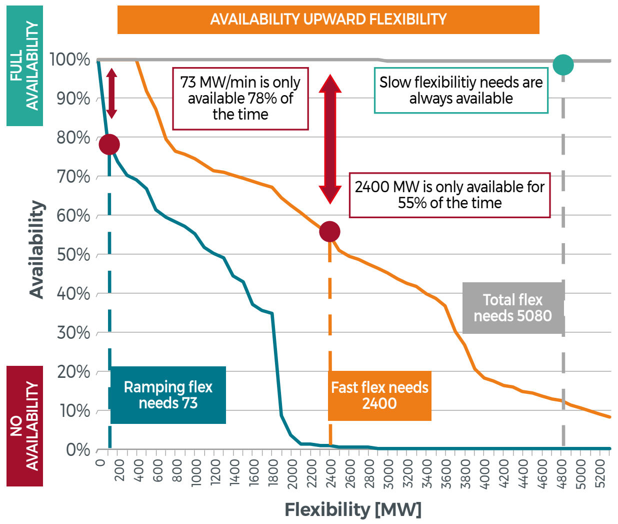


Figure 4-35 show that similar observations are made for the **available downward flexibility means in 2030.** Although the guaranteed ramping and fast flexibility shortages is far higher as for upward (fast flexibility needs are covered between 90 – 100% of the time) and it is therefore indicated by an orange indicator. However, these results also mean that in 2030, even when accounting for non-thermal capacity, reserve sharing with neighbouring countries and potential wind power reductions, some periods still face fast and ramping flexibility shortages. This could require specific measures (e.g. a reservation of downward capacity) and this evolution is to be monitored closely. Similar for upward flexibility, the slow flexibility needs are fully covered when taking into account export capabilities.

FIGURE 4-35: OPERATIONAL AVAILABILITY OF DOWNWARD FLEXIBILITY MEANS IN 2030

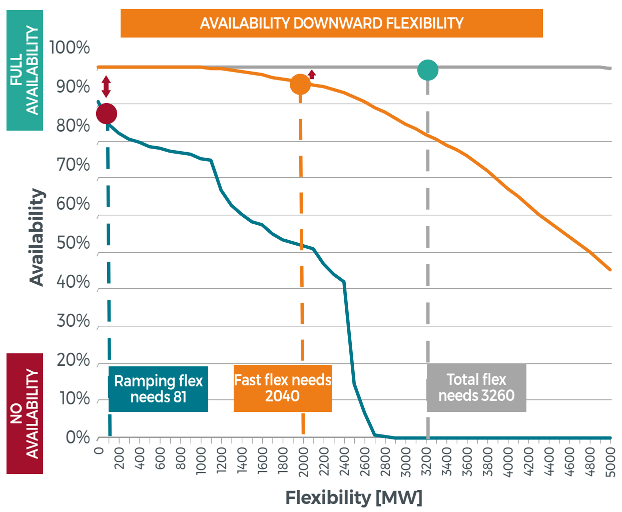


Figure 4-36 assesses the **contribution of different technology** types by means of distinguishing non-thermal, wind power (only for downward flexibility) and import / export of flexibility (mainly for slow flexibility) for the different types of flexibility. Simulations show that non-thermal capacity (such as market response, storage,renewable generation) has the potential to contribute substantially to the delivery of ramping and fast flexibility, and that this potential increases towards 2030 with the increasing share of different types of battery storage and demand-side management providers. Due to their fast start and ramping times, these generally do not require must run conditions (such as with some thermal units) when delivering ramping and fast flexibility, giving them an interesting potential as flexibility provider.

IMPACT OF NON-THERMAL CAPACITY, WIND POWER AND IMPORT / EXPORT ON THE OPERATIONAL AVAILABILITY OF FLEXIBILITY MEANS [FIGURE 4-36]

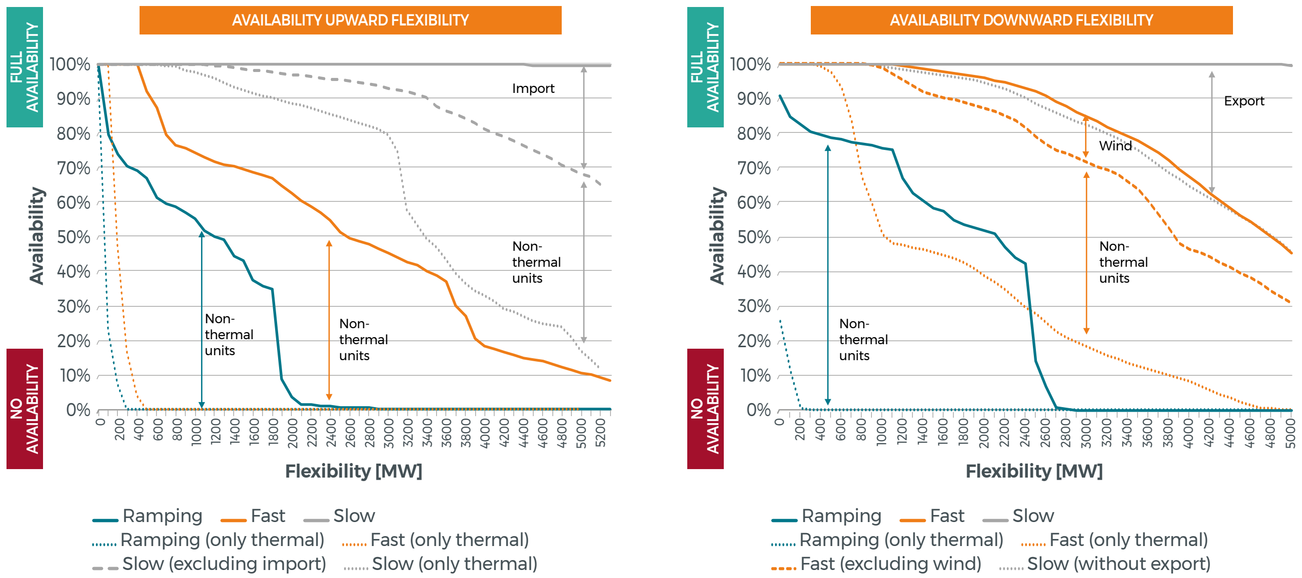
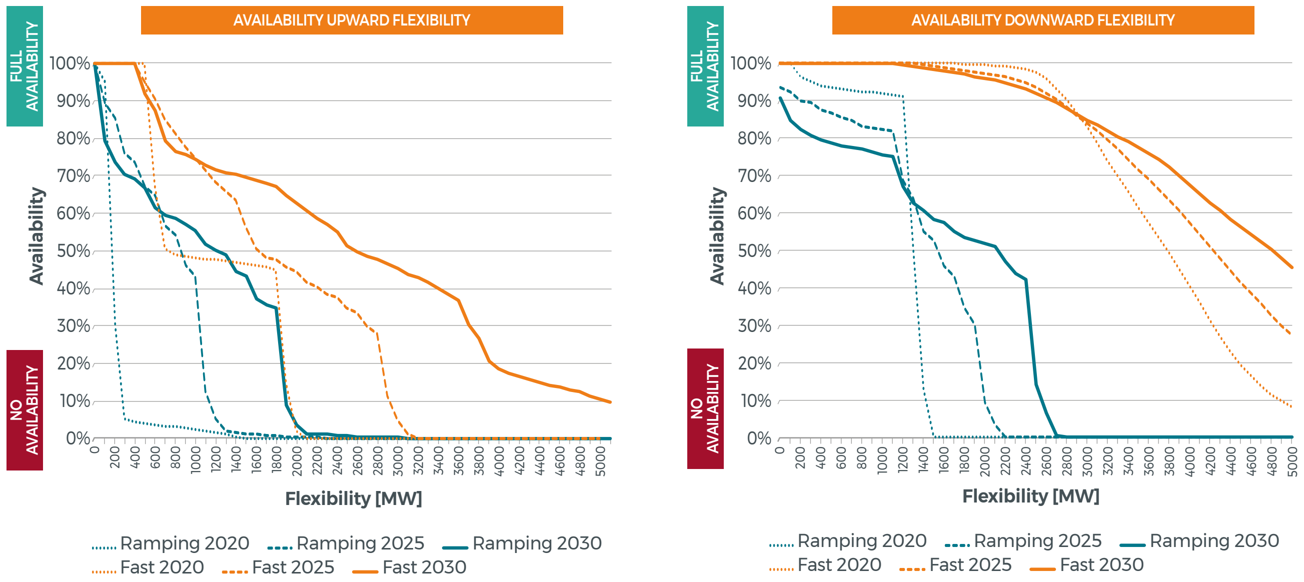


Figure 4-37 shows the **evolution of the available flexibility means between 2020 and 2030**. The impact on the slow flexibility is not depicted as it is fully available until 2025. It shows that available flexibility means increase on average (the curves are shifted to the right) which is mainly due to the integration of non-thermal capacity. This is shown by the distributions being shifted right. This is also confirmed when looking at the average availability indicator in Figure 4-33.

It is also observed that this does not necessarily increases the capacity which is guaranteed to be available (represented by the percentile P99.9 and P99.0 indicators). This is particularly the case for downward fast and ramping flexibility as can be seen in Figure 4-37. It is found that running hours of thermal power plants are reduced in the 'CENTRAL' scenario as from 2025 which results in less downward thermal flexibility, has a high availability (it explains the slight reduction of upward fast and ramping flexibility which is available with high availability). Furthermore, energy reservoirs of whichthe pumped-storage units are found to be more often fully charged limiting the downward flexibility abilities. It is observed (as shown in Figure 4-33) that the downward fast flexibility needs remain covered until 2020.

EVOLUTION OF OPERATIONALLY AVAILABLE FLEXIBILITY MEANS FROM 2020 TO 2030 [FIGURE 4-37]



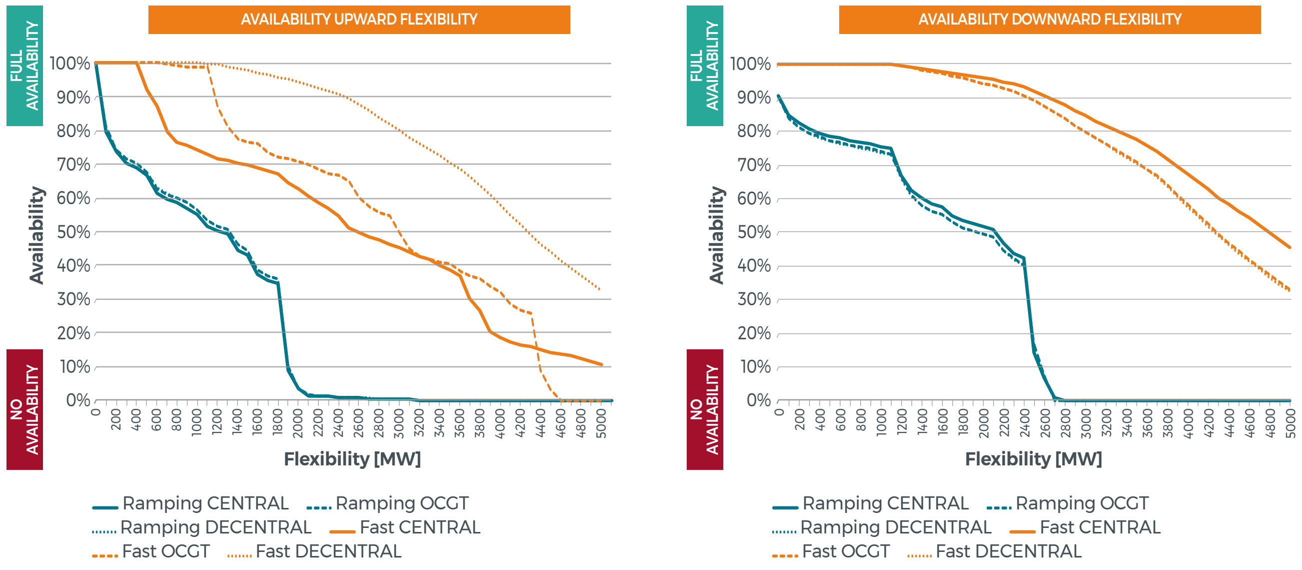
4.4.2.2. SENSITIVITIES

This section discusses the results of the two sensitivities conducted for 2030 : nuclear prolongation ('N-PRO') and the different technology types used to cover the system's adequacy needs ('Efficient Gas', 'Peakers', 'Decentral'). Results for 2025 depict the same trends as 2030 and are therefore not further discussed.

Firstly, it is shown that the technologies used to cover the remaining gap of the structural block mainly impact the available operational upward fast flexibility (Figure 4-38):

- as expected, the **fast available operational upward flexibility** is increased is due to the fact that OCGT or DECENTRAL units (diesels, turbojets, market response) can be activated fully within 15 minutes, which does not limit their contributions to fast flexibility. This is in contrast to CCGT units for which the start-up time does not allow to provide fast flexibility when not dispatched;
- in contrast, the **fast available operational downward flexibility** is only slightly reduced due to the fact that OCGT and DECENTRAL units face lower running hours (compared to CCGT units). Consequently, less downward flexibility can be provided;
- the **available operational ramping flexibility** is only impacted to a limited extent. This is explained by the fact that there are no fundamental differences between the relevant technologies concerning the ramping flexibility (all except market response) which all have to be dispatched before they can deliver ramping flexibility;
- the **available operational slow flexibility** (not depicted on the figure as 5000 MW is almost 100 % available for any sensitivity) is impacted to a very little extent as CCGT, OCGT and DECENTRAL show similar slow flexibility characteristics. All flexibility can be started, or stopped, in the time frame of slow flexibility (i.e. in less than 5 hours).

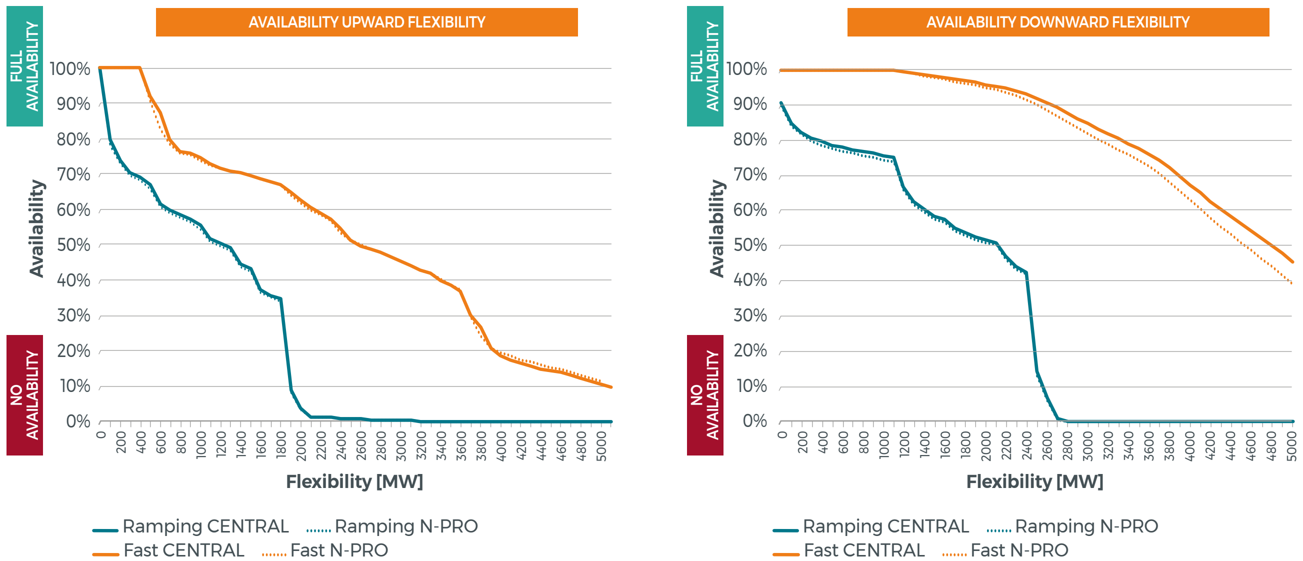
IMPACT OF NEW BUILD TECHNOLOGY ON THE OPERATIONALLY AVAILABLE FLEXIBILITY MEANS IN 2030 [FIGURE 4-38]



Secondly, it is shown that the impact of a **nuclear prolongation** on flexibility is relatively limited (Figure 4-39). The upward flexibility remains almost identical which is explained by the fact that upward fast or ramping flexibility is often delivered by the marginal unit. This means that replacing one or more generation units with alternative capacity has little effect. The same conclusion can also be drawn for other scenario's impacting the installed thermal capacity.

In contrast, the downward fast (and also ramping to lesser extent) flexibility is impacted as fewer thermal units will be dispatched resulting in less downward flexibility.

IMPACT OF THE 'N-PRO' SCENARIO ON THE OPERATIONALLY AVAILABLE FLEXIBILITY MEANS IN 2030 [FIGURE 4-39]



4.4.3. Summary of findings

In first instance, the installed flexibility means are compared with the flexibility needs. The analysis shows that over the period 2020 to 2030, there will be sufficient capacity installed in the system to cover the ramping, fast and slow flexibility needs. This is expected to be the case in every scenario and sensitivity where the installed capacity mix fulfills the adequacy needs of the system. This **means that no technical requirements will be needed for new capacity and that technology choices can be left open to the market**. Note that the adequacy assessment takes into account flexibility needs which are needed during periods with scarcity risk in order to ensure that the system is able to deal with forced outages, and relevant prediction risks even when facing scarcity in the day-ahead market.

This does not allow to make conclusions on the operational availability and economic efficiency of delivering this flexibility. Therefore, the available operational flexibility means are compared with the flexibility needs for each individual hour of the year and this for each Monte Carlo year. This allows to analyse whether the installed flexibility is sufficiently available in the intra-day and real-time. Indeed, in reality, it is possible that the required flexibility is unavailable when units providing flexibility are not dispatched and require a start-up time of several hours or when energy storage buffers are full or empty.

It is shown that at least **until 2030, it remains necessary to secure upfront a volume of operational flexibility to deal with variations of demand and generation**. Ensuring the operational availability of this flexibility is in particular relevant for upward fast flexibility (during the entire studied period 2020-2030), but also to minor extend for ramping flexibility. As some technologies can only contribute to fast flexibility types when already dispatched, a start-up would come to slow to deliver the flexibility in time. This is especially the case for thermal generation units, although also non-thermal capacity such as demand response may face such activation constraints.

However, **the downward fast flexibility needs are covered in 2020, but may require ensuring their operational availability towards 2025**, even when taking into account the contribution of non-thermal capacity, and even the potential reductions of wind power generation (the current offshore and large onshore wind power plants already demonstrate this capability today). Such periods will increase the relevance of technologies such as electricity storage to efficiently deal with periods of excess energy.

Results from the day-ahead simulations show that the **slow flexibility can always be covered with import and export, provided of course a liquid and well functioning European intraday market**.

Securing the operationally available capacity can be done by Elia (trough the balancing market) or by market players (trough price incentives on intra-day and balancing markets). For both up- and downward flexibility, **it is found that technologies such as demand response and storage contribute substantially to the delivery of fast flexibility where their cost structure allows reducing 'must run' or reservation costs**. Facilitating the development of new flexibility providers and valorizing their flexibility will facilitate the integration of renewable energy, and help realizing the energy transition. This can in last instance be resolved by the current balancing mechanisms in which reserve capacity is contracted by Elia to cover residual flexibility needs uncovered by the market. Results also show that non-thermal capacity has a large potential in contributing to these needs, as their technical characteristics and cost structure makes them often more suitable for close-to-real-time activations (e.g. batteries and some types of demand response).

4.5. Economic assessment

Economic results are very dependent on the installed capacity in Belgium, assumed prices for fuel and CO_2 and associated scenarios for neighbouring countries. In order to capture those uncertainties, the '**CENTRAL**' scenario for Belgium will be combined with:

- both the **'EU-BASE'** and **'EU-HiLo'** scenarios for neighbouring countries;
- both the **'REF'** and **'HIGH'** setting for **CO_2** prices;
- the different **capacity mixes** to fill the 'not-viable GAP' as presented in Section 4.2.6:
  - 'EVC + SR';
  - All existing units + 'Efficient Gas';
  - All existing units + 'Peakers';
  - All existing units + 'Decentral'.

First a view on the **generation mix** is provided identifying the generated electricity per type and imports/exports in the different settings.

The **revenues and running hours** of the different capacities are also given. Those result from an economic dispatch and depend on the economic assumptions.

Afterwards the **wholesale price** in the different settings is analysed. In addition, costs of the capacity mechanism (if any) are added to the picture.

In addition to the view on prices paid by consumers, a calculation from the **system perspective** is performed by calculating the investment costs and the market welfare differences between scenarios.

To complete the picture, as requested by several stakeholders, the economics of a **nuclear extension of 2 GW** after 2025 are provided.

4.5.1. Future electricity mix

HISTORICAL AND FUTURE ELECTRICITY MIX

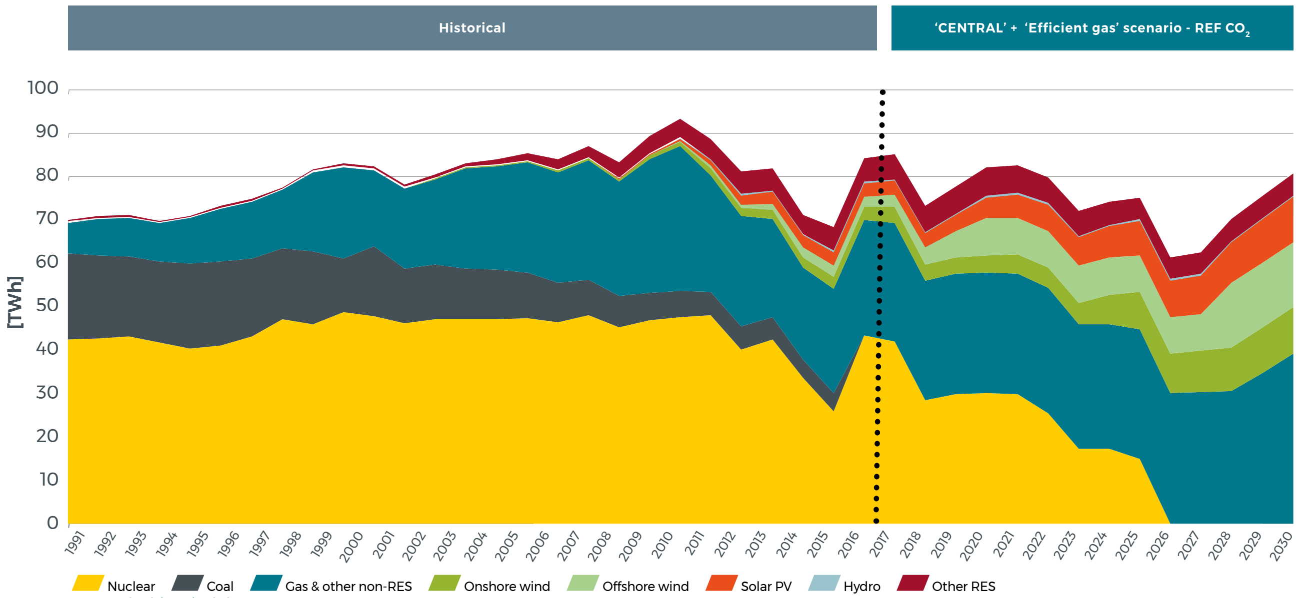
On an historical basis, as described in Section 2.1.1, the nuclear generation is the main source of electricity supply in Belgium. Until 2012, nuclear generation represented over half of the electricity mix for Belgium. From 2012 to 2016, the nuclear production dropped below 50% of the share due to the outages and safety investigations of nuclear units before increasing again in 2016.

After the nuclear phase-out, the renewable energy sources and gas-fired units will remain the predominant fuel used for generating electricity in Belgium. The level of gas-fired generation will greatly depend on the capacity mix that will be installed in Belgium and abroad, as well as the merit order ('gas before coal' or 'coal before gas'). In Figure 4-40, the historical and future electricity mix (based on the 'Efficient gas' scenario for new capacity) for the 'CENTRAL/EU-BASE' scenarios combined with the 'REF' CO_2 price is shown. Note that different assumptions lead to different levels of gas-fired generation in Belgium as highlighted in Figure 4-41. The depicted capacity mixes were chosen arbitrarily for illustration and do not intend advocating for any specific mix.

It can be clearly noted from the figure that the generation from wind and PV is planned to increase and could reach 50% of generated electricity in Belgium (around 40% of RES-E[2] share if comparing it to the electricity consumption). While the generated electricity from RES will double, its contribution to adequacy is limited (as highlighted in Section 4.1.3.1) and will need to be complemented with additional capacity.

2. The RES-E share is calculated on the electricity consumption. As Belgium is importing electricity during those years, the generated electricity in Belgium is lower hence the share of RES on the generated electricity will be higher than the share of RES on the cons–umption.

ELECTRICITY GENERATION PER FUEL TYPE IN BELGIUM FOR A GIVEN FUTURE CAPACITY MIX [FIGURE 4-40]

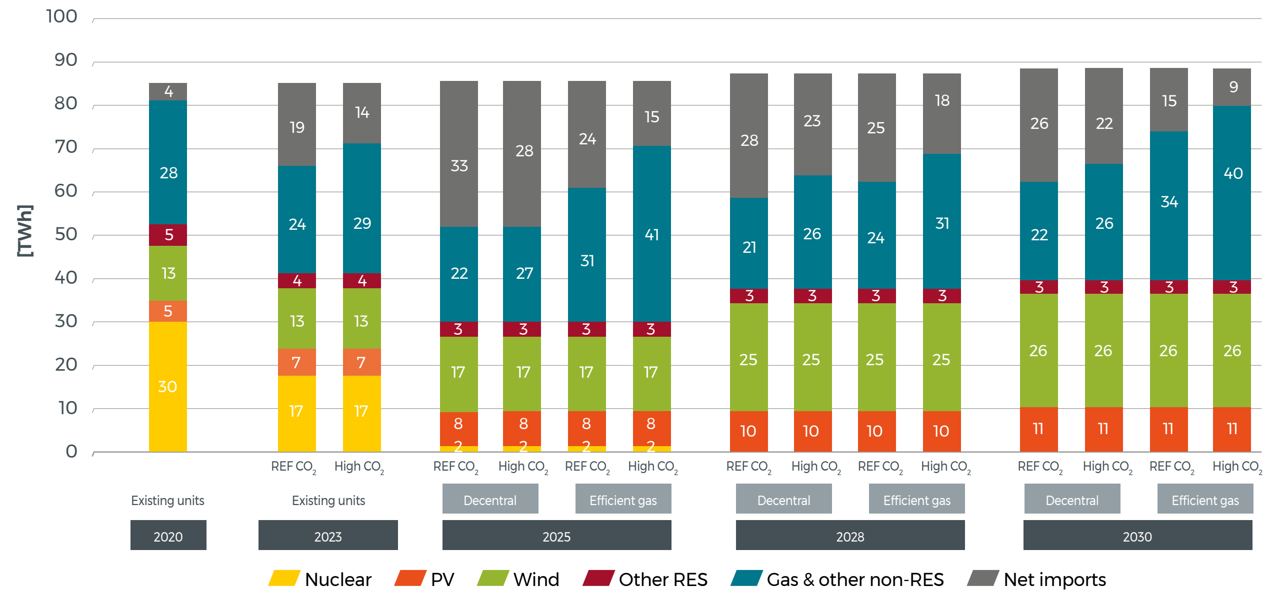


Source for historical data: FPS Economy

IMPACT OF THE CAPACITY MIX AND CO_2 PRICES ON THE ELECTRICITY MIX

RES generation will need to be complemented with other technology types to fulfil requirements on adequacy. The choice of this complementary capacity mix will have an effect on the import/export electricity balance for Belgium. In order to illustrate this effect, Figure 4-41 shows the electricity mix in Belgium in two different price settings for 2020 and 2023 and in 4 different settings as from 2025: 'HIGH' and 'REF' CO_2 prices combined with the 'Decentral' and 'Efficient gas' scenario. It can be observed that the nuclear generation will be replaced by gas and imports. In the long run, RES will also replace a large part of nuclear generation although the planned increase in RES does not allow this to be achieved straight after 2025. The level of gas and net imports will be determined by the composition of the capacity mix in Belgium (and abroad) and the CO_2 prices. Depending on those uncertainties, gas generation could range from 21 to 41 TWh on average per year.

IMPACT OF CAPACITY MIX AND CO2 PRICES ON THE FUTURE ELECTRICITY GENERATION MIX IN BELGIUM [FIGURE 4-41]



IMPACT OF THE CAPACITY MIX AND CO_2 PRICES ON THE IMPORTS/EXPORTS OF ELECTRICITY

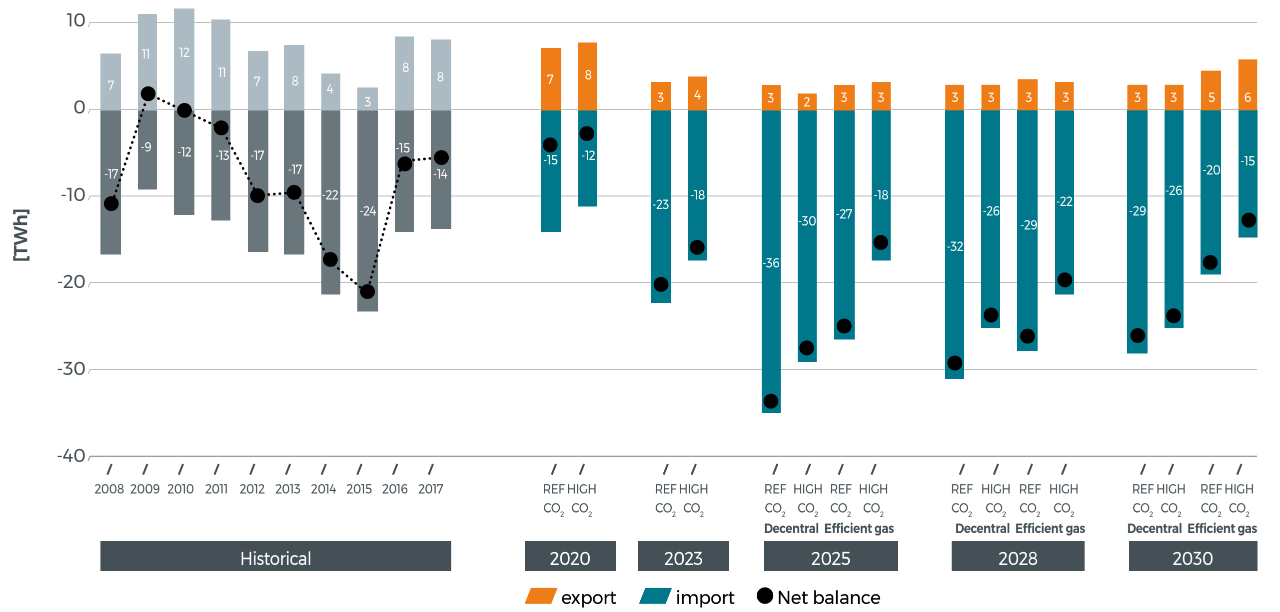
Historically, Belgium was mostly a net importer of electricity. This trend is observed until 2030 in the different scenarios simulated as illustrated in Figure 4-42. From 2011 to 2015, imports have almost doubled due to the limited availability of production capacity in Belgium (mainly nuclear) over several years. In 2016 and 2017, imports were back to the levels observed before 2012 thanks to the higher availability of the Belgian nuclear fleet.

With the increase of RES, more electricity is exchanged, taking advantage of different weather conditions across Europe. The cross-border exchanges between Belgium and its neighbours will be mainly driven by:

- The penetration of RES in Belgium and abroad;
- The fuel and CO_2 prices;
- The generating capacity mix in Belgium and abroad.

Figure 4-42 illustrates the historical cross-border exchanges in Belgium and the results for the 'Efficient gas' and 'Decentral' scenario combined with the 'REF' and 'HIGH' CO_2 price.

YEARLY IMPORTS/EXPORTS OF ELECTRICITY WITH BELGIUM IN THE 'CENTRAL'/'EU-BASE' SCENARIO (FOR THE 'DECENTRAL' AND 'EFFICIENT GAS' CAPACITY MIX COMBINED WITH 'REF' AND 'HIGH' CO_2 PRICES) [FIGURE 4-42]



4.5.2. Revenues and running hours of different technologies

While the needed 'GAP volume' identified in Section 4.1.2 is required to ensure an adequate system, the choice of the capacity to fill this gap will determine the amount of hours during which it will be dispatched. **The dispatch decision (hence the running hours) are the result of an economic optimisation** representing the actual functioning of the energy market which is mainly depending on three factors:

- the marginal cost of the capacities considered to fill the 'GAP volume';
- the merit order of the region (hence fuel and carbon prices, capacity mix abroad, etc.) for each hour;
- the consumption level that has to be met at each hour.

For a country such as Belgium which is very well interconnected, **the running hours of a given technology are mostly driven by its place in the European merit order**. In order to provide an indication on how many hours a given technology would be dispatched, Figure 4-43 provides simulated running hours for 5 different technologies considering their associated marginal costs/activation prices.

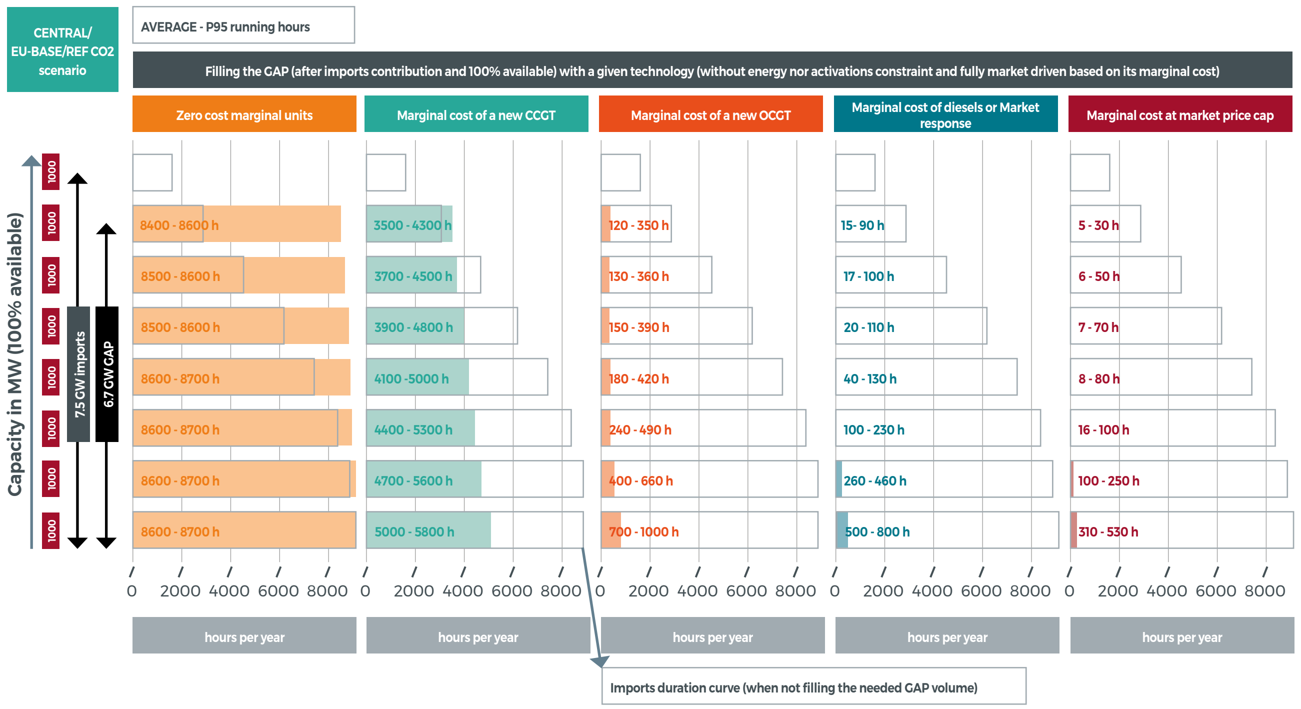
RUNNING HOURS BY BLOCKS OF 1000 MW

Running hours are the results of the economic dispatch, i.e. market functioning. Filling the 'GAP volume' with a certain technology could result in running hours ranging between 5 and 8000 hours per year.

In order to derive the numbers, it is assumed that the 'GAP volume' identified in the 'EU-BASE' scenario for 2025 is filled with the 6.7 GW required volume to be adequate. For each technology type, the running hours per year per block of 1000 MW are provided (the first 1000 MW of new CCGT would be dispatched for 5000 hours on average and 5800 hours in a percentile of 95% situation).

In addition, the duration curve for imports needed when no 'GAP volume' is assumed is also provided. This curve is the same for each technology (as it is defined when no 'GAP volume' capacity is assumed). The import duration curve is also shown by blocks of 1000 MW and up to 7500 MW (the maximum import capacity – see Section 2.7.2). This enables a comparison as to whether Belgium would be importing or exporting energy and whether it represents large or small quantities.

RUNNING HOURS ARE VERY DEPENDENT ON THE TECHNOLOGY CHOICE TO FILL THE IDENTIFIED GAP VOLUME FOR 2025 [FIGURE 4-43]



Starting from the left chart and moving to the right, it can be observed that the running hours are sharply decreasing when assuming technologies with higher marginal costs/activation price. Filling the 'GAP volume' with 'zero cost marginal capacity' (without energy/activation limitations) will lead to running hours of more than 8000 per year, while filling it with technologies having a marginal cost/activation price close to the price cap will lead to running hours between 500 h and 5 h (depending on the amount of capacity installed).

A decrease can also be observed when adding more capacity of the same type to the system. Additional capacity in the system will push some of the capacity in the merit order hence it will result in lower prices. There will be more hours when the marginal price will be set by the technology which was added hence its running hours might decrease as it will be the marginal technology.

With the first technology (on the left), it can also be observed that there is more energy generated than needed in Belgium (mainly for the last 3 GW), and that this generation will be exported to other countries while for the other technologies a higher relative share of imports are observed.

When the 'GAP volume' is filled by new CCGTs, it results that the running hours are in the range of 3000 to 6000 hours depending on the amount installed. It is important to note that the chosen setting for the CO_2 price also influences the results (this is tackled in the next paragraphs).

For peakers or other technologies with a high activation price, the amount of running hours varies between 15 and 1000 hours. Those are expensive technologies to operate (in terms of marginal cost) hence most of the capacity abroad will first be dispatched and imported to Belgium before activating them.

On the right chart, the amount of hours during which the price cap is reached is indicated. Those hours correspond to the loss of load hours if no 'GAP volume' capacity would have been installed in Belgium. This would mean that first imports would be used (at any price) and the capacity would be installed to cover the moments when the price cap is attained.

If all existing units would be considered to fill the 'GAP volume' it would not change much the figure. Given that existing units have a marginal price between new CCGTs and diesels, the following is therefore valid:

- the first 3 blocks (from the bottom) are representative for the running hours of the 'zero cost marginal unit' and 'new CCGT';
- for 'new OCGT', 'diesel' and 'price cap marginal' the running hours of the last 3 blocks (from the top) are representative;

Results for 2028 and 2030 are available in Appendix H.3

REVENUES AND RUNNING HOURS OF DIFFERENT TECHNOLOGIES FOR DIFFERENT ADEQUATE CAPACITY MIXES

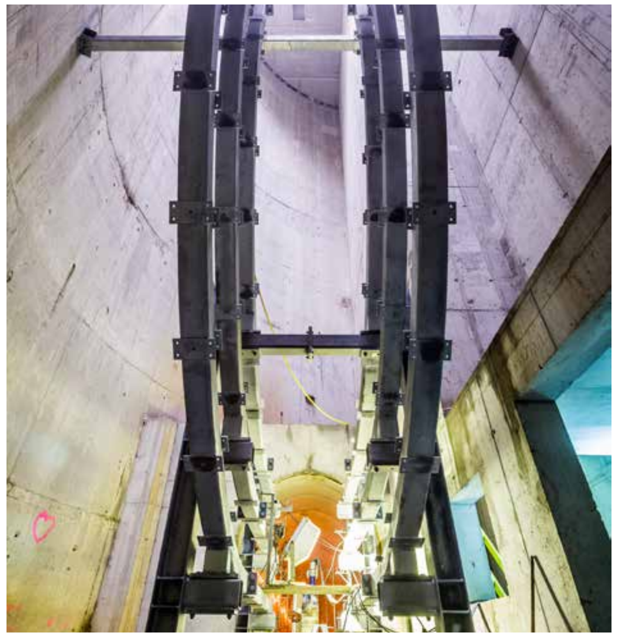
Assuming a certain intervention in the market (under the form of a market-wide CRM), it is possible to calculate the market revenues (from the energy market) for the different technologies. For this, two of the settings ('Efficient gas' and 'Peakers') and both the 'REF' and 'HIGH' CO_2 prices scenarios will be used. As explained in Section 4.2.6, the 'GAP volume' is first filled with all existing units (4.7 GW or 4.3 GW de-rated capacity) and then with the assumed capacity mix.

The following charts are providing a view on revenues of new CCGTs (for a theoretic '1 MW' of capacity with the best efficiency on the system and no outages). It results that depending on the capacity mix for Belgium and on carbon prices, the revenues are differing by around 30 €/kW for a given year.

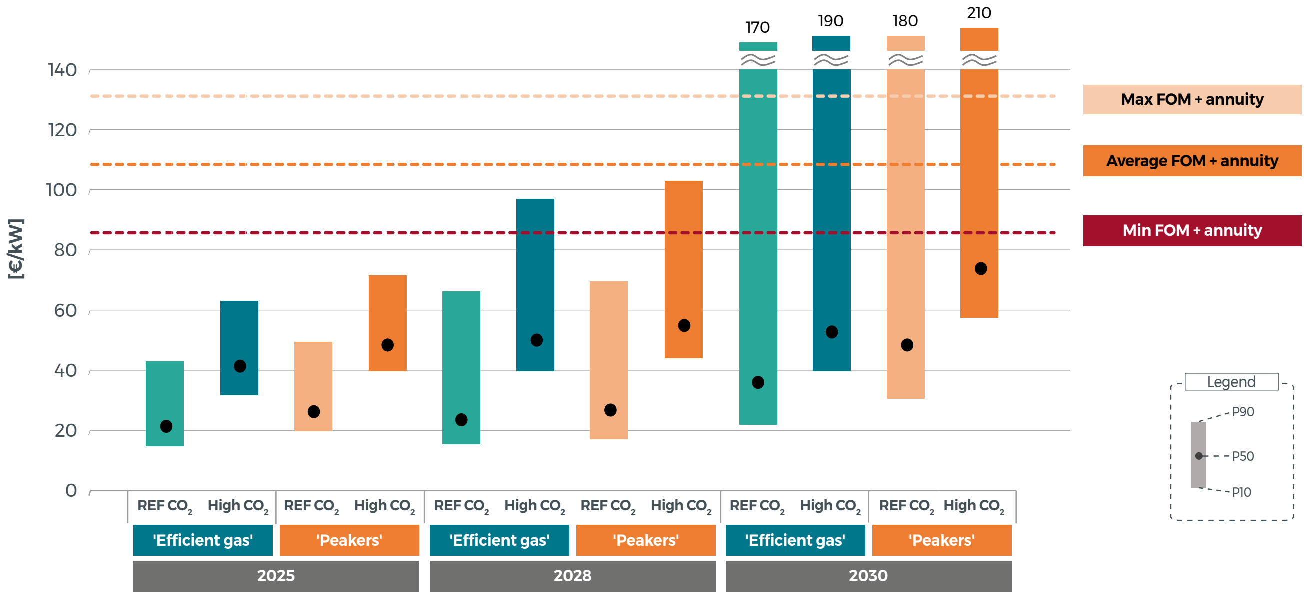
Based on the results obtained for all scenarios from 2025 to 2030, it can be stated that the inframarginal rents for the most efficient CCGT unit installed in Belgium will be insufficient to cover even the lowest annuity costs (including the FOM).

The profitability of such units is strongly linked to gas and CO_2 prices. In this way, in a 'HIGH CO_2' price setting where the prices are higher, higher revenues for CCGTs are identified in all scenarios.

The inframarginal rents also show a significant volatility depending on the weather conditions of a given year. This volatility increases with the penetration of climate dependent variables and the fact that Belgium relies more and more on market response and storage for adequacy.



INFRAMARGINAL RENT FOR THE MOST EFFICIENT CCGT INSTALLED IN THE SYSTEM IN BELGIUM FOR 2025, 2028 AND 2030 - EU-BASE IN 'EFFICIENT GAS' AND 'PEAKERS' SENSITIVITIES [FIGURE 4-44]



RUNNING HOURS FOR THE MOST EFFICIENT CCGT INSTALLED IN THE SYSTEM IN BELGIUM FOR 2025, 2028 AND 2030 - EU-BASE IN 'EFFICIENT GAS' AND 'PEAKERS' SENSITIVITIES [FIGURE 4-45]

Results for the other technologies are available in Appendix H.2

4.5.3. Comparison between different capacity mixes and market designs for 2025

A market-wide CRM ensures a robust security of supply and brings market welfare by decreasing wholesale prices which at least compensates for the cost of the mechanism.

In order to evaluate the differences between the current 'energy-only' market design complemented with strategic reserves and an energy market complemented with a market-wide CRM, the three capacity mixes defined in Section 4.2.6 complemented with the 'EVC+SR' setting will be used. The 'CENTRAL' scenario for Belgium is used for all other assumptions on installed capacities.

CAPACITY MIXES:

The comparison starts by quantifying the needed capacity to be adequate (which is the same for all the settings (in a given scenario)). For the 'EU-BASE' scenario this amounts to 6.7 GW (100% available), while for the 'EU-HiLo' this equals 8.2 GW (100% available).

'EOM + SR' case:

In the 'EVC' setting, only the economically viable capacity 'in-the-market' is retained. This was calculated in Section 4.2.2 and amounts to:

- 2.6 GW (100% available) in the 'EU-BASE' scenario. Without derating it would equal an installed capacity of 2.8 GW;
- 4 GW (100% available) in the 'EU-HiLo' scenario. Without derating it would equal an installed capacity of 4.3 GW.

The 'not-viable GAP' identified is assumed to be 'out-of-market' in a strategic reserve mechanism and amounts to:

- 'EU-BASE': 4.1 GW of strategic reserves – 100% available (of which 2.4 GW assumed newly developed capacity);
- 'EU-HiLo': 4.2 GW of strategic reserves – 100% available (of which 3.9 GW assumed newly developped capacity).

It is important to note that there is no guarantee of finding such large volumes of strategic reserve capacity, in particular if newly developed volumes are required.

'EM + CRM' case:

In all other settings, an intervention is assumed in the form of a market-wide CRM. All needed capacity, including newly developed capacity, is therefore considered 'in-the-market'. First, all existing capacity is assumed to stay in the market (following the market-wide CRM: 4.7 GW (without derating)). Additionally the identified new capacity, ranging from 2.4 GW ('EU-BASE') to 3.9 GW ('EU-HiLo'), is filled with different capacity mixes: 'Efficient gas' with CHP, ' Efficient gas' without CHP, 'Peaking' and 'Decentral'.

'STRUCTURAL BLOCK' YEARLY FIXED COSTS:

For each setting, the investment and fixed costs can be quantified (based on the economic assumptions presented in Section 2.9.4). For this exercise the middle range of the invesment and fixed costs from Figure 2-62 will be used. For the 'EVC' setting a WACC of 10% is used which reflects a higher risk for investors. In the more stable environment induced by the market-wide CRM, a WACC of 7.5% is used. Note that taking the same WACC for both market designs would not alter the conclusions.

The cost of the 'in-the-market' capacity is quantified as the sum of the annuities (for new capacity and refurbished) and FOM (for existing and new capacities). Note that all capacities in the 'structural block' were taken into account to calculate the yearly fixed costs (which includes market response, storage and CHP); this only impacts the absolute value but not the delta between the different settings (because all assume the same quantities from the 'CENTRAL' scenario).

The cost of 'out-of-market' capacity is assumed to have a yearly cost of 36 €/kW which corresponds to the historical price of strategic reserves in Belgium. Note that such a price is representative for existing capacity and a limited amount of new market response. With larger volumes of strategic reserves (which is the case here), finding new capacity at such a yearly cost could seem optimistic. It was therefore assumed that around 500 MW of new capacity would be priced at 36 €/kW. Additional new capacity to be found would have a price of 50 €/kW (see Section 2.9.5 for more information).

COST OF CAPACITY MECHANISMS (WHEN CALCULATED ON THE WHOLESALE PRICE):

When evaluating consumers' or producers' perspectives, the assumed transfer between consumers and producers (i.e. the capacity remuneration payments) need to be considered (see Section 2.9.5 for more information). It was assumed that a market-wide CRM would cost between 3 to 5 €/MWh (based on the [PWC-1] study – See Section 2.9.5) for the consumer and that the strategic reserve transfer cost (in €/MWh) is equal to the total fixed costs calculated, divided by the total consumption of Belgium.

SYSTEM INDICATORS:

For each of the settings, a market simulation was performed. This leads to several key indicators for the system:

- The **market LOLE**, i.e. the average number of hours per year that the market would clear at the price cap prior to any intervention of 'out-of-market' capacity, is 10.5 hours for the 'EOM+SR' case. This is not compliant with the legal criteria although it allows all 'in-the-market' capacity to remain economically viable. The strategic reserve is dimensioned to guarantee a LOLE under the legal criteria, i.e. to reduce the LOLE from 10.5 to 3 hours. In the 'EM+CRM' cases, the LOLE in the market is under the legal criteria as the identified need is procured by the market and ensured via the CRM;
- The **market EENS**, i.e. the average amount of energy that is not served per year after the market would clear at the price cap prior to any intervention of 'out-of-market' capacity, is 21.3 GWh in the 'EOM+SR' case (see also Section 4.2.5 for more details on the EVC results). The market EENS in the 'EM+CRM' cases is around 3 GWh.

As a result of the economic dispatch, the **net imports** of Belgium are also provided. Those show that the cases with high marginal cost generation ('Peakers' and 'Decentral') have higher net imports while the other two cases result in lower net imports of around 10 TWh. This was also further detailed and analysed in Section 4.5.1. The 'EOM+SR' case results in higher net imports for Belgium as around 4 GW of capacity is 'out-of-market' (and is therefore not dispatched economically against the European merit order and only activated once all import options have been depleted).

MARKET WELFARE:

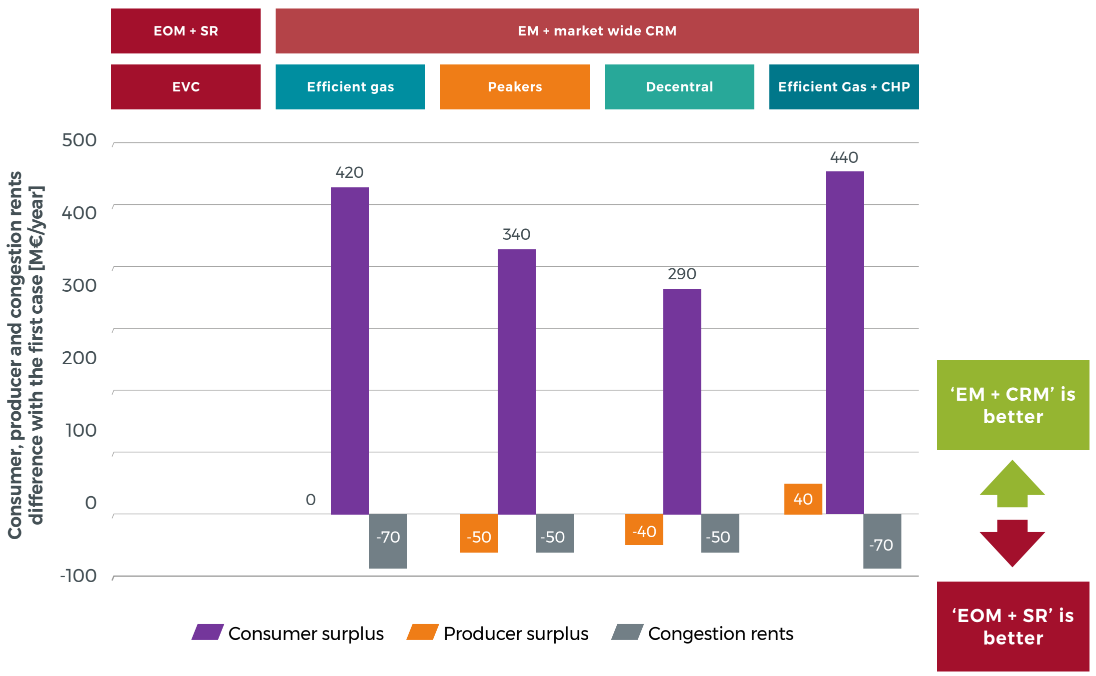
The market welfare is the sum of the consumer surplus, producer surplus and the part of the congestion rents allocated to Belgium (see Section 3.3 for more information). It results from the market simulation based on the hourly prices, generation and cross border exchanges.

The market welfare (with the consumer surplus, producer surplus and congestion rent split) is depicted in Figure 4-46 for the 'EU-HiLo' scenario for 2025 (with REF CO_2). The market welfare is always defined as a delta. In this comparison, the first case ('EOM+SR') is taken as the reference (note that the choice of the reference has no impact on the results).

It can be concluded that:

- There were consumer gains between 290 and 440 M€ in the 'EM+CRM' cases (compared to the 'EOM+SR' case). This is due to lower wholesale prices compared to the 'EOM+SR' case as there are fewer price spikes;
- The producer surplus stays stable (between -50 and +40 M€). Two effects can explain this 'status-quo'. On the one hand, prices are lower than in the 'EOM+SR' case (hence revenues are lower as well). On the other hand, there is more 'in-the-market' capacity which captures additional revenues and increases the producer surplus, compensating part of the loss. The cases with efficient gas units capture more revenues than the 'peaking units/decentral' cases. This explains the difference between the various capacity mixes;
- The congestion rents are slightly reduced by around 50 M€. This is due to lower prices in Belgium compared to the 'EOM+SR' case. The price spread with neighbouring countries is smaller which is directly affecting the congestion rents.

MARKET WELFARE SPLIT COMPARED TO THE 'EOM + SR' CASE (CENTRAL/EU-HILO SCENARIO - REF CO_2 PRICES) [FIGURE 4-46]



SUMMARY OF THE DIFFERENT INDICATORS:

Figure 4-47 gives an overview of the scenario quantification and indicators presented in the previous paragraph. The figure includes both 'REF' and 'HIGH' CO_2 price scenarios for the 'CENTRAL'/'EU-HiLo' scenario. The results for the 'EU-BASE' scenario are also provided in Appendix H.4.

ECONOMIC ASSESSMENT OF DIFFERENT MARKET DESIGN AND CAPACITY MIXES FOR 2025 [FIGURE 4-47]

2025 – 'CENTRAL'/'EU-HiLo' scenario | REF | HIGH

Scenario	Market design	EOM + SR	EM + market wide CRM			
	Which kind of capacity delivers the needed new capacity ?	No intervention, only viable capacity in the market	Efficient gas	Peakers	Decentral	Efficient Gas + CHP
CHP, MR, Storage		'EneryPact' figures for storage (1 GW), PSP (1,4 GW), Market response (2 GW) and constant CHP (2 GW)				
Installed GAP capacity (8.2 GW – 100%)	IN the market	Existing =4.3 GW	All existing = 4.7 GW New CCGT = 4.1 GW	All existing = 4.7 GW New gas engine/OCGT= 4.1 GW	All existing = 4.7 GW New diesel= 4.1 GW (if MR = 12 GW)	All existing = 4.7GW New CHP = 1 GW New CCGT = 3.1 GW
	OUT of the market	SR = 4.2 GW - 100% available (of which new capacity in SR = 3.9 GW)				
Structural block Costs	Annuity of 'in the market' capacity	-350 M€	-730 M€	-590 M€	-600 M€	-800 M€
	Annuity of 'out of the market' capacity	-210 M€	0 M€	0 M€	0 M€	0 M€
System indicators	Market LOLE	10.5 h	3 h	3 h	3 h	3 h
	Market EENS	21.3 GWh	3 GWh	3 GWh	3 GWh	3 GWh
	Net imports	28 to 33 TWh	5 to 17 TWh	27 to 32 TWh	28 to 33 TWh	5 to 16 TWh
Market Welfare	BE Market Welfare difference (CS, PS, CR) *Compared to the [EOM-SR] case*	-	350 to 410 M€	240 M€	200 M€	410 to 430 M€
Conclusions						
From the system perspective	Net market welfare difference *(the higher, the better)*	-560 M€	-380 to -320 M€	-350 M€	-400 M€	-390 to -370 M€
From a consumer perspective	€ Wholesale price variation *Compared to the [EOM-SR] case*	-	-4.3 to -3.9 €/MWh	-3.0 €/MWh	-2.6 €/MWh	-4.5 to -4.1 €/MWh
	⇔ Welfare transfer	+2.4 €/MWh	+3 to +5 €/MWh (estimated cost range for a market-wide CRM)			
	€ Net Price Difference *(the lower, the better)*	+2.4 €/MWh	-1.5 to +2.4 €/MWh			
Delivering security of supply		High volatility. 4 GW strategic reserve needed of which at least half new capacity	Robust security of supply guaranteed by design. 'In the market' capacity brings market welfare and whosale price reduction which at least compensates for the cost of the market-wide mechanism.			

From a system perspective, the 'EM+CRM' cases have a net market welfare gain between 150 and 250 M€ per year compared to the 'EOM+SR' case. This is calculated as the yearly market welfare gain (consumers and producers surplus and congestion rents) minus yearly fixed costs (including investment costs in new and refurbished capacity) for each case.

From a consumer's perspective, one can calculate the wholesale price decrease between the 'EM+market-wide CRM' and the 'EOM+SR' case. Depending on the capacity mix this ranges from -2.6 to -4.5 €/MWh. These prices do not include any additional costs paid by the consumers for capacity mechanisms (in or out-of-the market). Those are added in the second step:

- the SR cost is estimated at around 2.4 €/MWh from the 210 M€ total cost (assuming that the SR cost would be spread equally across all consumers – 87 TWh);
- The market-wide CRM cost is estimated between 3 and 5 €/MWh (see Section 2.9.5 for more information).

Applying those additional costs on the wholesale price **results in a price advantage for the 'EM+CRM' cases of between 0 €/MWh to 3.9 €/MWh.**

Moreover, the 'EOM+SR' case would also result in higher price volatility, more imports and the necessity to find 3.9 GW of new capacity 'out-of-market' (2.4 GW in the 'EU-BASE' scenario). To the extent it would be possible to find such large 'out-of-market' volumes and it would be desirable as a system to maintain and operate such large volumes 'out-of-market', one may question if an 'out-of-market' mechanism such as strategic reserves would provide an appropriate solution at all (cf. section 2.1.3).

It is also important to keep in mind general differences between a setting with strategic reserves versus a setting with a market-wide CRM. As already mentioned earlier and accounted for in the study through different WACC values depending in the market design, the more stable revenue streams resulting from an 'EM+CRM' setting may resort in a positive effect on the financing cost due to more certain and stable revenue streams. This is a positive effect in terms of overall welfare.

Boom-bust cycles in terms of price spikes and 'in-the-market' investments in new capacity are strongly dampened in an 'EM+CRM' as any need for new 'in-the-market' capacity is streamlined through the 'market-wide CRM' via forward auctions and are no longer exclusively driven by price signals in the energy market. As investors exhibit myopic behaviour (i.e. react by investing only when actual high prices are experienced, rather than anticipating future high prices), in a sector which is characterized by some investment inertia due to potential long lead times for development of new capacity, boom-bust cycles in energy prices and investments in new 'in-the-market' capacity are much more likely to occur in an 'EOM(+SR)' setting than in an 'EM+CRM' setting where the need for 'in-the-market' capacity is steamlined through the CRM auction. Stated otherwise, whereas an SR mechanism is as such capable of maintaining the adequacy levels set by a reliability standard (if the required 'out-of-market' capacity can be found), the investment signals from the energy market have not altered. This means that for 'in-the-market' capacity to be developed, investment incentives remain untouched (also in terms of (un)certainty, etc.).

Finally, as in a market-wide CRM typically longer term contracts could be provided under certain conditions, it may facilitate new entry of market players and thereby contribute to enhancing overall competition (in what is today a rather concentrated market).

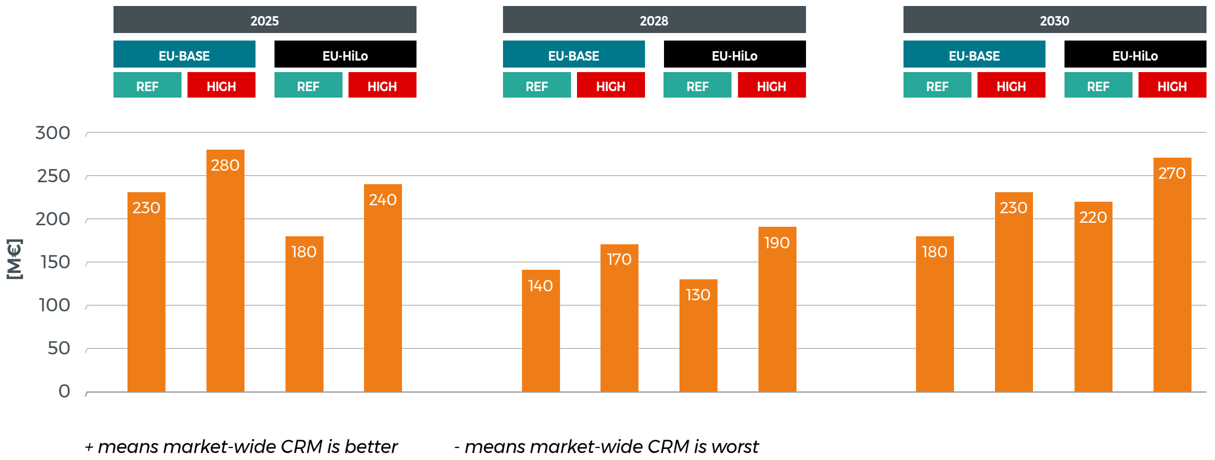
i Results for the 'EU-BASE' scenario are available in Appendix H.4.

4.5.4. Summarised results for all time horizons

In order to assess the impact after 2025, the 'Efficient Gas' setting was compared to the 'EOM+SR' setting. As shown in the previous section, a different 'in-the-market' setting would not significantly change the conclusions in terms of impact on net welfare and wholesale prices.

First, the net welfare gain is computed for each time horizon and scenario ('EU-BASE', 'EU-HiLo', 'REF'/'HIGH' CO2) and is presented in Figure 4-48. **Results show that a 'market-wide CRM' gives a net welfare benefit between 100 and 300 M€/year depending on market conditions**. The net welfare already integrates the annuity for the new and refurbished capacity.

NET MARKET WELFARE (WELFARE AND TOTAL INVESTMENTS COSTS) GAIN OF THE 'EFFICIENT GAS' COMPARED TO 'EOM+SR' SCENARIO [FIGURE 4-48]

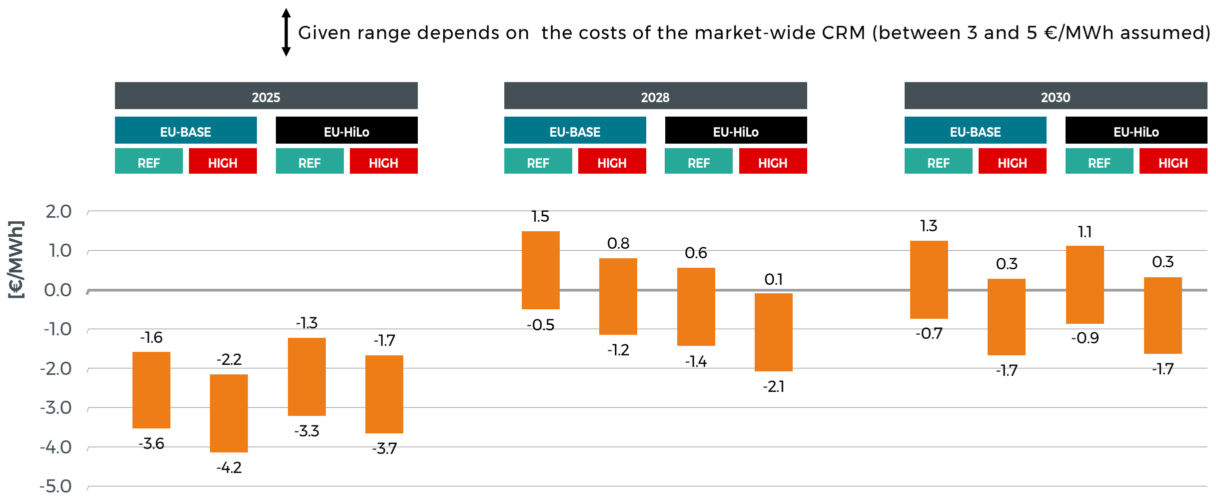


The wholesale price can also be computed for each time horizon and scenario and is shown in Figure 4-49. The wholesale price indicated in the figure includes the transfer costs (from consumers to producers) of the different capacity mechanisms in both settings. For the 'EOM+SR' setting, it is the cost of the 'out-of-market' capacity that needs to be contracted to comply with the adequacy criteria. In the 'Efficient gas' scenario, the assumed cost of the 'market-wide CRM' is estimated between 3 and 5 €/MWh (see Section 2.9.5 for more information). The price range presented is due to the estimated range of the 'market-wide CRM' cost.

It can be observed that for 2025, there is a clear benefit for the 'EM+CRM' case in terms of prices paid by the consumer (between 1.3 and 4.2 €/MWh).

For 2028 and 2030, the benefit is less explicit although it depends on the scenario and the market situation (it ranges from -2.1 €/MWh to +1.5 €/MWh). It can therefore be concluded that introducing a market-wide CRM will not cost more than continuing with the current mechanism but as indicated in the previous section, additional benefits are brought by introducing it.

WHOLESALE PRICE DIFFERENCE (IN WHICH THE CAPACITY MECHANISM COSTS ARE INTEGRATED) BETWEEN 'EFFICIENT GAS' & 'EOM+SR' [FIGURE 4-49]



BOX 15 - ABSOLUTE WHOLESALE PRICE EVOLUTION

The wholesale electricity price is calculated by the model as the marginal price for each hour of each market zone based on the variable costs of the generation, storage and market response fleet. The wholesale price does not include any additional payments (taxes, subsidies, grid costs...). See Section 3.1.2 for more information on the modelling approach.

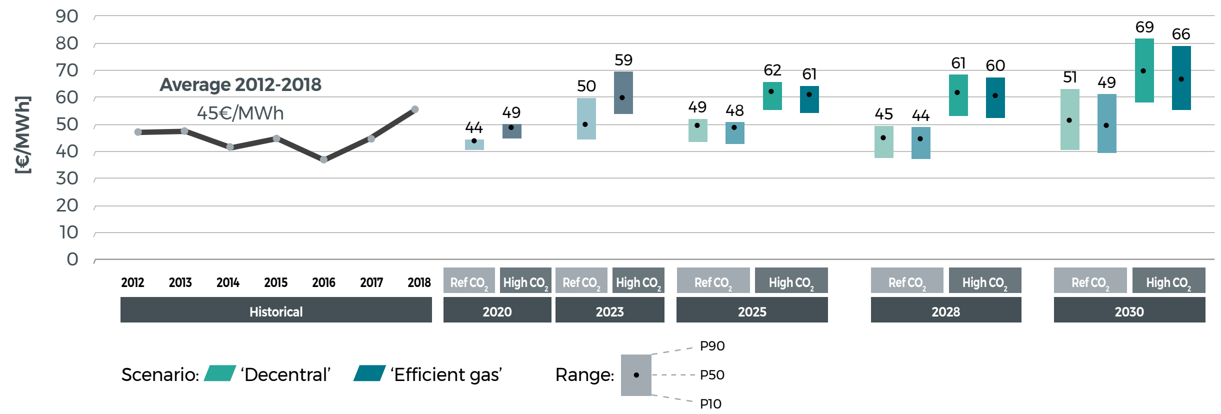
The model simulates the electricity market as if all the energy was sold on the day-ahead market. This implies the assumption that day-ahead price levels propagate to other timeframes (e.g. forward prices) and supply contracts[3] . In order to compare the output prices of the model, the average yearly historical prices of the day-ahead market are provided.

Figure 4-50 illustrates the historical evolution of electricity wholesale prices and those calculated for the different future time horizons. In order to understand the main drivers, the 'REF' and 'HIGH' scenarios for CO_2 prices are provided combined with both 'Decentral' and 'Efficient gas' settings (which are all scenarios, assuming sufficient investments to remain adequate 'in-the-market') for 2025, 2028 and 2030. For 2020 and 2023, only all existing units were considered to fill the 'GAP volume'.

The results show that the major drivers for the wholesale price are the associated fuel and CO_2 prices. In the next decade, the price will mostly be set by gas-fired units hence a change in the marginal cost of gas-fired plants will have a significant impact on average electricity prices. The thermal capacity planned to be decommissioned in Europe (around 100 GW) will also have an impact on the prices although it will be compensated for by the addition of renewable capacity. Such an effect can be observed in the evolution of the electricity prices over time. There is a tendency to increase in the first five years which is linked to the large amount of coal and nuclear decommissionings, while in 2028 the positive effect of RES can be observed by a stabilisation of the wholesale prices. In 2030, additional thermal closures in Europe (and higher CO_2 prices) lead to an increase of the wholesale price. It is important to note that those prices reflect only the wholesale price, any transfer from consumer to producers, subsidies scheme or taxes are not included.

The choice was made to only present two of the four capacity mixes as the difference between 'CHP' and 'Efficient gas' and between 'Decentral' and 'Peakers' is very small (<0.5 €/MWh). In addition, it can be observed that the difference between both capacity mixes retained in the picture leads to a very small price difference (around 1 €/MWh in 2025 to 3 €/MWh in 2030). This is due to the fact that Belgium efficiently uses its interconnections to maintain its prices at a lower level by importing cheaper energy abroad. This conclusion is based on 'adequate' scenarios where the 'remaining GAP' is filled by 'in-the-market' capacity.

AVERAGE WHOLESALE ELECTRICITY PRICE IN BELGIUM FOR DIFFERENT CO_2 SCENARIOS AND NEW TECHNOLOGIES [FIGURE 4-50]



3. To what extent this assumption holds entirely, e.g. including forward prices anticipating price spikes, is not straightforward to judge. Academic literature has so far provided no unanimous answer in the context of electricity markets.

4.5.5. Nuclear extension

As requested by several stakeholders, the nuclear extension was also assessed from an economic point of view. As indicated in Section 4.1.3.1, extending 2 GW of nuclear capacity reduces the need in terms of adequacy by 1 GW. Therefore it reduces the required new capacity from 3.9 GW to 2.9 GW in the 'EU-HiLo' scenario for 2025.

4.5.5.1. COST OF NUCLEAR EXTENSION

The cost assumptions for the nuclear extension were taken from public sources:

- The **cost of a 10-year lifetime extension** is based on the available data for the prolongation of the nuclear reactors Doel 1 and 2 in 2015. This results in **around 800 €/kW** [ENG-1] ;
- The **nuclear production costs** (including fixed costs) taken into account in this study are **around 30 €/MWh** which is based on the nuclear rent calculation made by different parties in 2011 [NBB-1], to which inflation was applied:
  - The variable costs assumed in this study (fuel + VOM) equal 14 €/MWh, in line with ENTSO-E studies (nuclear fuel price of 0.47 €/GJ and VOM of 9 €/MWh);
  - The remaining 16 €/MWh are treated as fixed costs. Assuming 7500 running hours for a nuclear unit, it results in a Fixed O&M (FOM) of 120 €/kW.

Given the above assumptions, for a 2 GW nuclear extension:

- the investment annuity is 233 M€/year considering a WACC of 7.5% and 260 M€/year with a WACC of 10%;
- the FOM is 240 M€/year.

A rounded total revenue between 470 M€ and 500 M€ per year is needed to cover the lifetime extension and fixed costs.

Note that no other indirect costs apart from those mentioned above are considered.

4.5.5.2. SCENARIO SETTING

The nuclear extension sensitivity will be analysed both in an 'EOM+SR' and in an 'EM+CRM' design.

4 settings will be compared:

- 'EOM+SR';
- 'EOM+SR+Nuclear';
- 'EM+CRM';
- 'EM+CRM+Nuclear'.

For the 'EM+CRM' cases, the 'Efficient gas' setting will be shown. However, a different capacity mix will not change the conclusions (see Section 4.2.4).

For the 'EOM+SR' cases, the economically viable capacity as identified in Section 4.2.2 will be taken into account as 'in-the-market', the rest being 'out-of-the-market'. When extending 2 GW nuclear, this might in reality however reduce the amount of viable capacity 'in-the-market' as identified in Section 4.2.2.

Given the historical unavailability of nuclear units and its impact on the market prices and revenues, 2 sensitivities will always be assessed and results are provided with a range:

- Extension of 2 GW with a forced outage rate of exclusively 3.5 % as the unavailability rate;
- Extension of 2 GW of which only 1 GW is available for the whole year.

Both carbon price scenarios ('REF' and 'HIGH') will be used and integrated in the range.

The 'EU-HiLo' scenario will be presented in this section. The other scenarios and time horizons are included in Appendix H.5 with the three main indicators summarised in both the 'EOM+SR' and 'EM+CRM' designs:

- Wholesale price difference (including cost of capacity mechanism);
- Net market welfare (including nuclear extension costs, nuclear producer revenues, producer surplus, consumer surplus and congestion rents);
- Nuclear net producer surplus (nuclear revenues minus the extension costs).

Results for other scenarios and years are available in Appendix H.5

RESULTS

4.5.5.3. NUCLEAR EXTENSION ECONOMICS IN AN 'EOM+SR' AND 'EM+CRM' DESIGN

The results are summarised in a table in Figure 4-51. Those include the breakdown of the different components (costs, welfare, wholesale price differences etc.). The split between costs and welfare was also made for the nuclear producer surplus and costs in order to evaluate the revenues and gain/loss of the nuclear units.

Impact of nuclear extension on wholesale prices (which include capacity mechanism transfers costs between consumers and producers):

On the consumer side, there is a limited gain on wholesale market prices when extending nuclear by 2 GW. This can be explained by the fact that in the coupled CWE market prices are mostly determined by the marginal fossil or renewable units. If the nuclear fleet is fully available, the impact is slightly higher in the 'EOM+SR' case as extending nuclear reduces the amount of scarcity hours (around 1.5 €/MWh). If 50% of the nuclear fleet is unavailable, it results in no or limited gain. In an 'EM+CRM' setting the gain in wholesale prices is lower (around 1 €/MWh). The range shown in the table is due to the considered nuclear availability.

Nuclear producer surplus:

The nuclear fixed costs per year (including lifetime extension costs) amount to between 470 and 500 M€. Looking at the expected net revenues of the nuclear units (revenues from the market from which fixed costs are deducted), those could result in a gain or a loss, depending on the availability of the nuclear fleet, ranging between -200 M€ and +300 M€.

Net market welfare:

In an 'EOM+SR' setting, the net market welfare is slightly higher with a nuclear extension although the gain is limited to around 100 M€ per year for consumers and producers (excluding nuclear producers). This is driven by lower wholesale prices benefitting the consumer surplus compensated by a lower producer surplus. Adding the nuclear producer perspective into the 'net market welfare' could yield results ranging from an overall gain of up to 500 M€ down to a loss of around 100 M€. This difference is exclusively due to the nuclear availability.

In an 'EM+CRM' setting, the nuclear extension results in a loss for non-nuclear producers which is higher than the limited gain of consumers. A net welfare loss of around 50 M€ per year can therefore be expected. Adding the nuclear producer perspective into the 'net market welfare' could yield results ranging from an overall gain of up to 250 M€, down to a loss of around 300 M€.

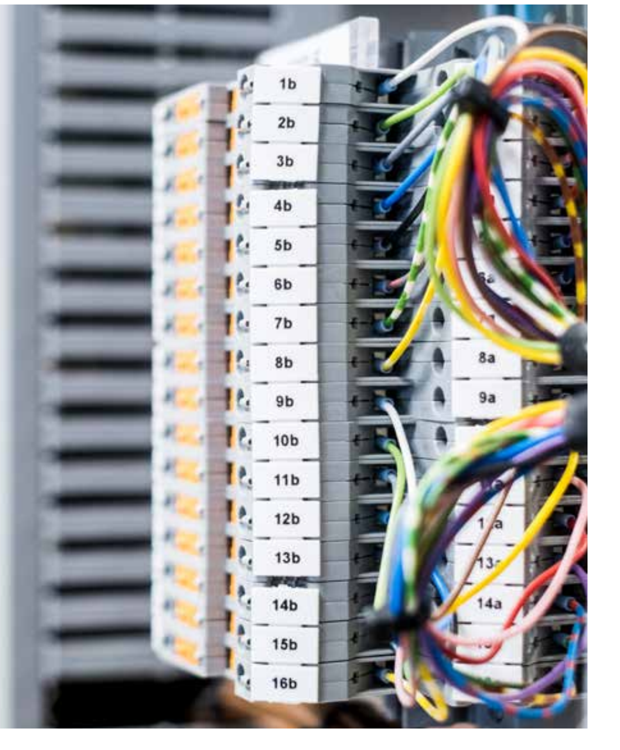
Summary of findings:

The above mentioned results are also confirmed looking at more years or scenarios (see Appendix H.5).

It can be concluded that:

- The nuclear extension has a positive but limited impact on wholesale prices;
- It has a negative impact on the producer surplus of other capacity in the system;
- The net market welfare is therefore mostly driven by the nuclear producer surplus which can be positive if nuclear units show good availabilities or negative if those are unavailable for long periods.

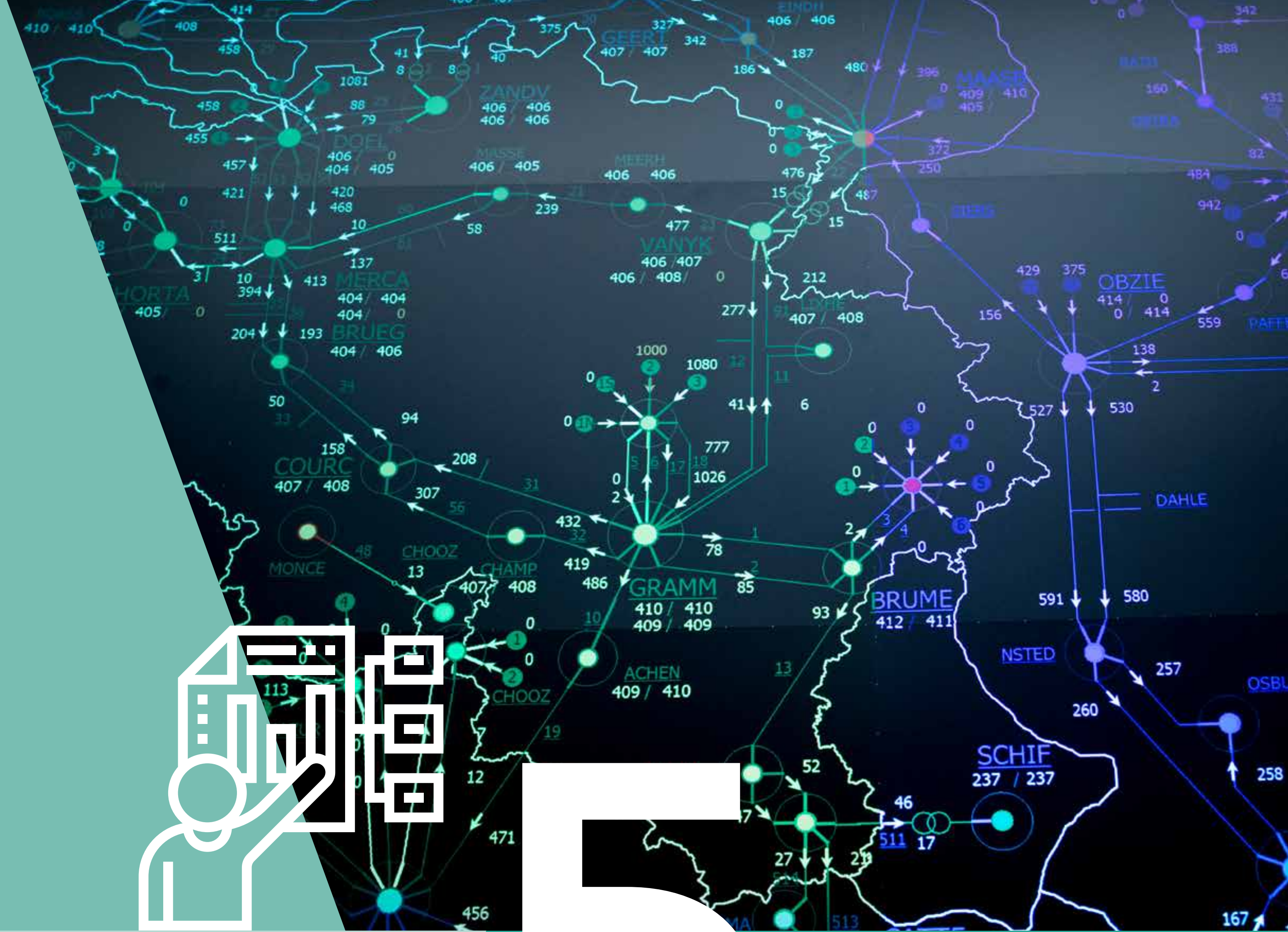
Given the large amount of capacity still to be found 'out-of-the-market', the nuclear extension sensitivity does not overthrow the conclusion that the 'EM+CRM' design is more robust in delivering security of supply than the 'EOM+SR' design. A nuclear extension in an 'EOM+SR' design still requires a large amount of strategic reserves to be contracted. In 2025, SR volume needs surpass 3 GW of which a large part needs to be new capacity: 1.4 GW in the 'EU-BASE' scenario and 2.9 GW in the 'EU-HiLo' scenario.



ECONOMIC ASSESSMENT OF DIFFERENT MARKET DESIGN AND CAPACITY MIXES FOR 2025 WITH/WITHOUT NUCLEAR EXTENSION [FIGURE 4-51]

2025 - 'CENTRAL'/'EU-HiLo' scenario — REF — HIGH

Scenario	Market design	EOM + SR		EM + market wide CRM	
	Nuclear extension +2 GW		☢		☢
	Which kind of capacity delivers the needed new capacity ?	No intervention, only viable capacity in the rmaket	No intervention, only viable capacity in the market	Efficient gas	Efficient gas
CHP, MR, IN the market		'EneryPact' figures for storage (1 GW), PSP (1.4 GW), Market response (2 GW) and constant CHP (2 GW)			
Installed GAP capacity (8.2 GW - 100%)	IN of the market	Existing =4.3 GW	Nuclear = 2 GW Existing =2.8 GW	All existing = 4.7 GW New CCGT = 4.1 GW	Nuclear 2 GW All existing = 4.7 GW New CCGT = 3.1 GW
	OUT of the market	SR = 4.3 GW - 100% available (of which new capacity in SR = 3.9 GW)	SR = 4.8 GW - 100% available (of which new capacity in SR = 2.9 GW)		
Structural block Costs	Annuity of 'in the market' capacity	-350 M€	-290 M€	-730 M€	-640 M€
	Nuclear extension annuity & FOM	0 M€	-500 M€	0 M€	-470 M€
	Annuity of 'out of the market' capacity	-210 M€	-260 M€	0 M€	0 M€
System indicators	Market LOLE	10.5 h	7.5 h	3 h	3 h
	Market EENS	21.3 GWh	17 GWh	3 GWh	3 GWh
	Net imports	28 to 33 TWh	10 to 28 TWh	5 to 17 TWh	15 to -2 TWh
Market Welfare	BE Market Welfare difference (CS, PS, CR) and excluding nuclear producer surplus *Compared to the [EOM-SR] case*	-	-50 to 0 M€	350 to 410 M€	200 to 290 M€
	Nuclear producer surplus *Compared to the [EOM-SR] case*	-	300 to 840 M€	-	280 to 810 M€
Conclusions					
From the system perspective	Net market welfare difference, excluding nuclear producer surplus and extension costs *(the higher, the better)*	-560 M€	-600 to -550 M€	-380 to -320 M€	-440 to -350 M€
	Net market welfare difference (including nuclear producer surplus and costs) *(the higher, the better)*	-560 M€	-800 to -210 M€	-380 to -320 M€	-630 to -10 M€
From a consumer perspective	€ Wholesale price variation *Compared to the [EOM-SR] case*	-	-2.0 to -0.4 €/MWh	-4.3 to -3.9 €/MWh	-5.7 to -4.2 €/MWh
	⇔ Welfare transfer	+2.4 €/MWh	+3.0 €/MWh	+3 to +5 €/MWh (estimated cost range for a market-wide CRM)	
	€ Net Price Difference *(the lower, the better)*	+2.4 €/MWh	+1.0 to +2.6 €/MWh	-1.3 to +1.1 €/MWh	-2.7 to +0.8 €/MWh
From the nuclear producer perspective	Nuclear net revenues (where fixed cost are deducted)	-	-200 to +340 M€	-	-190 to +340 M€
Delivering security of supply		High volatility. More than 4 GW of strategic reserve needed of which at least 2.9 GW new capacity	Robust security of supply guaranteed by design. 'In the market' capacity brings market welfare and whosale price reduction which at least compensates the cost of the market-wide mechanism.		



5

Conclusions

This short, concluding chapter first provides an overview of the study's objective, followed by a factual overview of the process and stakeholders' engagement. Afterwards the main assumptions and data used for this study are summarised. Finally, a synthesis of the results and main insights is provided.

5.1. Study objective and process

Legal basis and objective

The present study is the implementation of Elia's legal duty to provide an analysis of the country's adequacy and flexibility for the next 10 years and is entirely compliant with the modalities as foreseen in the Belgian Electricity law.

This study provides a very accurate and detailed view on the adequacy outlook for the next 10 years on the basis of a state-of-the-art methodology, and as such it could serve as support for the Belgian authorities to justify the need for a CRM in Belgium when in discussions with the European institutions. It is important to note however, that this study is not designed as the basis for the calibration of the parameters or volumes required in the framework of such a CRM.

In addition, a new Regulation of the European Parliament and of the Council on the internal market for electricity (recast) was recently approved on 22 May 2019 as part of the 'Clean Energy for all Europeans Package' (CEP). Chapter IV of the Electricity Regulation deals with Resource Adequacy (Articles 20-27). The vast majority of the provisions of this Regulation will be applicable as from 1 January 2020. The methodologies on the European resource adequacy assessment and the reliability standard referred to in Art. 23, 24 & 25 are however not adopted yet. Therefore, there are to date no such methodologies to date which could be used as a basis for this study.

The former notwithstanding, Elia has deployed a lot of care to ensure that this '10-year adequacy and flexibility' study proactively takes into account this Electricity Regulation as much as possible (public consultation on input data, publication and transparency of remarks and the study itself, probabilistic methodology, flow-based modelling, central scenario with sensitivities, LOLE and EENS results, economic analysis, etc.).

As required by the Belgian 'Electricity Law', a flexibility assessment is conducted to analyse whether the future system is able to deal with expected and unexpected variations of generation or demand (for instance due to forced outages of generation units or generation/demand forecast errors). This becomes increasingly important following the massive integration of renewable generation. This flexibility analysis investigates whether the installed capacity has the capabilities to ensure the operational balance of the electrical system (or identifies minimum technology requirements), and whether specific flexibility challenges lie ahead.

Process and stakeholder involvement

As stipulated in the 'Electricity Law', the basic assumptions and scenarios, as well as the methodology used for this study should be determined by the transmission system operator *in collaboration* with the FPS Economy and the Federal Planning Bureau (FPB) and *in concertation* with the Regulator.

Right from the start, no distinction was made between the involvement of the FPS Economy and the Federal Planning Bureau on the one hand, and the Regulator on the other hand. Instead, a working group involving designated representatives from each institution was established to exchange information, present and discuss the approach, progress, results, etc. Several meetings and discussions have taken place with this working group since November 2018.

In addition, a public consultation for all market parties was organised about the input data of the 'CENTRAL' scenario that is used for this study. Stakeholders were also asked to provide requests for sensitivities. Significant contributions have been received from the market parties (over a hundred remarks and suggestions), which are summarised in a public consultation report. All suggested sensitivities were taken into account (within the limitations of the model) and many other remarks led to concrete changes in the elaboration of the study.

Specific attention is given to the new, state-of-the-art methodology for the flexibility assessment. This methodology was presented to the stakeholders in detail during a dedicated workshop.

5.2. Methodology and assumptions

Adequacy method

The methodology for the resource adequacy assessment of this study is in line with the current European assessments, i.e. the ENTSO-E Mid-term Adequacy Forecast (MAF). The other Belgian adequacy assessments are also in line with this study's methodology, given that those had been aligned to the MAF since its first edition. The method consists of a probabilistic 'Monte-Carlo' type model with an hourly time resolution applied on 34 different climate years, combined with a large amount of availability draws on generation and HVDC links. It also includes a 'flow-based' capacity calculation approach for the countries within CWE. In total, 21 countries are analysed and taken into account for this study.

Flexibility method

A new, state-of-the-art methodology was developed for the flexibility assessment. It focuses on the risks of unpredicted variations in demand or generation after day-ahead markets. No distinction is made whether this flexibility is provided by the market, or by Elia via its reserves. When sufficient flexibility is available in the system, and with a well-functioning electricity market, the largest part is expected to be covered by the market itself. The flexibility method is based on:

- A profound analysis of the flexibility needs based on a statistical analysis of historic forecasts of renewable and decentral generation, as well as forced outages;
- These needs are thereafter compared with the available flexibility in the system, based on (1) the installed capacity mix and (2) the hourly schedules of this capacity to determine the hourly operationally available flexibility means.

Scenario framework

The input data are based on the most up-to-date estimations, already integrating the proposed political ambitions with respect to increases in e.g. the development of renewables (solar, onshore and offshore wind), storage, market response, interconnection capacity, etc. On the demand side, energy-efficiency measures are also taken into account.

In addition to one 'CENTRAL' scenario, a multitude of sensitivities is analysed in this study. The results are robust over this multitude of sensitivities and scenarios, showing a confirmed need for new capacity in a wide range of possible future situations.

Belgian assumptions

The sources for the estimations for Belgium are mainly the (draft) 'National Energy and Climate Plan' at the federal and regional levels, as submitted to the European Commission at the end of 2018. Furthermore, those are complemented with the 'Energy Pact' and the approved Federal Network Development Plan for Belgium.

Those sources include further RES development to achieve a share of more than 40% RES-E by 2030 (including a 'second offshore wave' to reach 4 GW in the coming decade), the nuclear phase-out based on the law and different proposed measures on energy efficiency.

European and grid assumptions

The used dataset is based on the most up-to-date information collected within ENTSO-E. A close interaction has taken place with neighbouring countries in order to receive the latest information on their systems. In total 21 countries are modelled in this study. The study includes all known policies on coal and nuclear trajectories (including the recent 'Coal Commission' recommendation in Germany).

In a nutshell:

- In the coming decade, 100 GW of coal and nuclear capacity is to be phased out in Europe (of which the major part is in Western Europe);
- Since the publication of the previous '10-year adequacy and flexibility study' (April 2016), it has been announced that an additional 26 GW will be decommissioned by 2025. This major change has a significant impact on the energy availability abroad.

Finally, the 'Clean Energy Package' (with respect to the ambitions in terms of available cross-border capacity, the so-called 'minRAM70%' rule) serves as the main future working hypothesis.

Flexibility characteristics

For the flexibility assessment, a flexibility register has been developed including all of the technological capabilities that can achieve flexibility (ramp rate, start-up time, energy limits) from all the capacity types which are taken into account. The data is collected by Elia based on a literature study, and reviewed and complemented by stakeholders during the public consultation on the input data.

5.3. Insights on results

Need for new capacity

As from 2025, once the nuclear phase-out is completed, there is a structural need for new capacity that increases over time up to 3.9 GW. This need includes about 1.5 GW to deal with uncertainties in terms of the availability of generation or interconnection capacity in other countries beyond Belgium's control.

Even when part of the nuclear fleet (2 GW) would be prolonged and bearing in mind its reasonable availability with respect to adequacy, a structural need for new capacity remains over time.

The need of 3.9 GW can be covered by any kind of technology (on top of the already assumed capacity in the 'CENTRAL' scenario) such as thermal generation, renewable energy sources, market response and storage, but the proportional contribution of each technology to adequacy varies according to their respective energy constraints, availability of primary energy, weather conditions, etc.

Notwithstanding the significant contribution to overall welfare and price convergence of interconnection capacity during many hours of the year and the substantial amount of interconnection capacity assumed to be available for the market, at moments crucial from an adequacy perspective, the (location of the) available energy in neighbouring countries turns out to be the limiting factor.

Already prior to 2025, i.e. from winter 2022-23 onwards, there is an identified structural need for new capacity in Belgium due to newly announced generation closures in neighbouring countries taking place in parallel with the first steps of the nuclear phase-out in Belgium. The identified need for new capacity in this period is more than 1GW.

To maintain Belgium's adequacy in this changing context, additional measures will be needed as from winter 2022-23. The current strategic reserve mechanism has only been approved until winter 2021-22. Additional measures are needed to bridge the period 2022-25, after which the general market-wide capacity remuneration mechanism would become active.

It is important to bear in mind that the current strategic reserve mechanism has only been approved until winter 2021-22. Action should therefore be undertaken by the authorities to cover this need in the period prior to the first delivery of the upcoming CRM. Several solutions could be considered to cover these needs. While the CRM remains the only solution to overcome the need as from 2025, for the transition period 2022-25 both a continued use of a strategic reserve mechanism could be an option, as well as considering earlier delivery years of the CRM may provide a solution. Although timely action is required, at least both those options either already exist or are under full development. To the extent other credible solutions would exist, they should also be taken into consideration.

Need for market intervention

Economic analysis indicates that without a structural market intervention, the energy-only market signals will probably not provide the necessary investment incentives to ensure that the identified need for new capacity to maintain Belgium's security of supply is being fulfilled. It can therefore be concluded that there is a need for a structural market intervention to ensure adequacy as from 2025[1].

Not only is the need significant in terms of volume and structural over time, it is also clear that without new capacity, Belgian adequacy would not be guaranteed. This confirms that strategic reserves can no longer be considered as the appropriate instrument to ensure adequacy after 2025. According to the assumptions of this study and taking into account overall welfare effects, a market-wide capacity remuneration mechanism, as recently foreseen in the Belgian Electricity law, seems indeed the best option.

Robustness of results

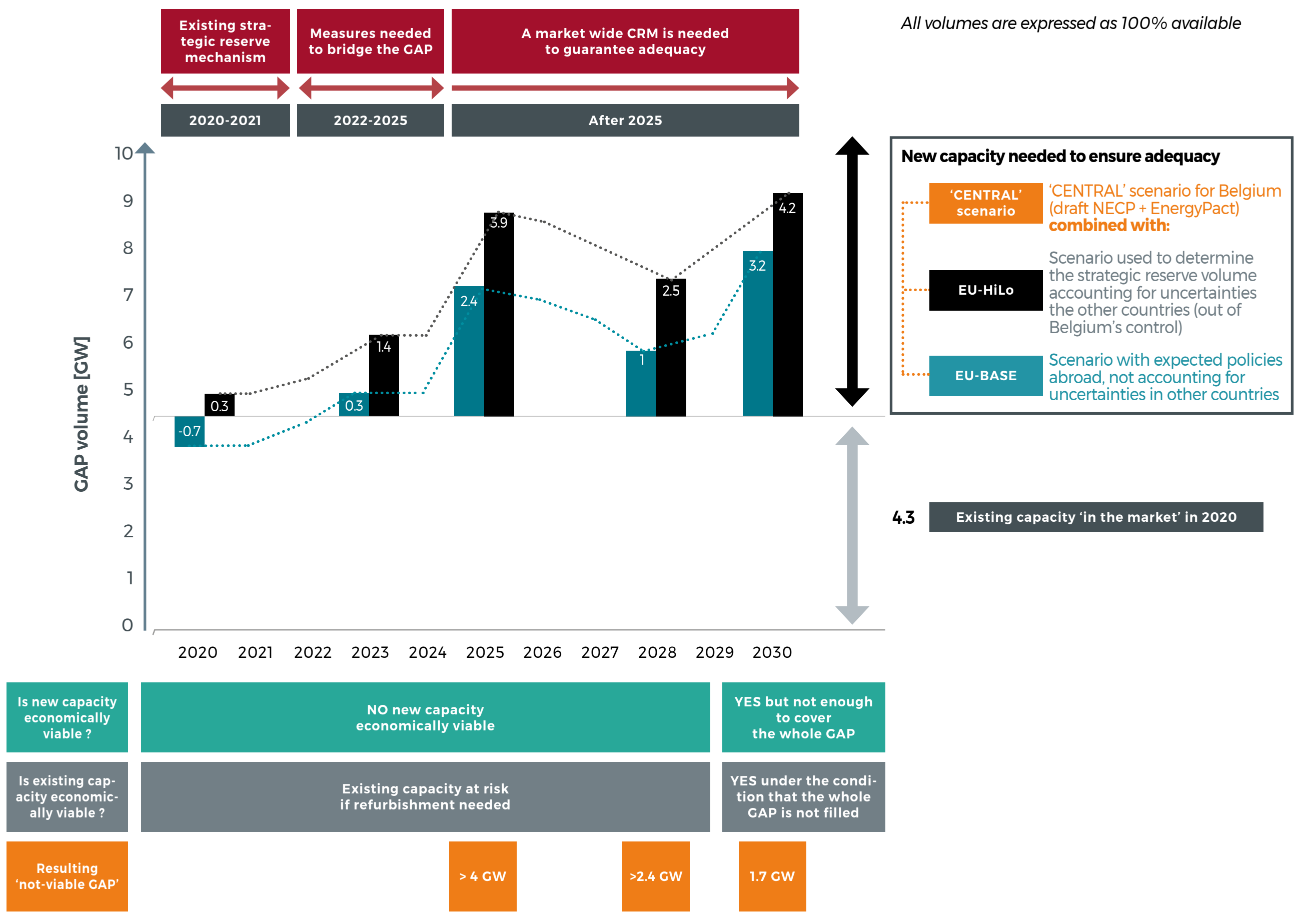
The results in terms of structural need as well as economic viability are robust when considering several sensitivities related to potential evolutions in terms of demand, policy measures impacting the overall capacity mix, carbon prices, etc.

Bearing in mind that the market model used for this study already assumes perfect competition, no entry barriers for the assumed capacities throughout the different scenarios, and in general a well-functioning market, the results remain robust even when implementing further energy market improvements. This remains true even when higher maximum clearing prices (price caps) are considered in a specific sensitivity.

The study also demonstrates that a market-wide CRM ensures a robust security of supply and brings market welfare by decreasing wholesale prices which at least compensates for the cost of the mechanism.

1. Under the revenue & cost assumptions taken for this study. If there would be certainty on the very short term that such a volume would be developed in the market without any support scheme, this conclusion might be impacted.

NEW CAPACITY NEEDED AND VIABLE CAPACITY WITHOUT INTERVENTION AND POLICY RECOMMENDATIONS TO ENSURE AN ADEQUATE SYSTEM IN THE COMING 10 YEARS [FIGURE 5-1]

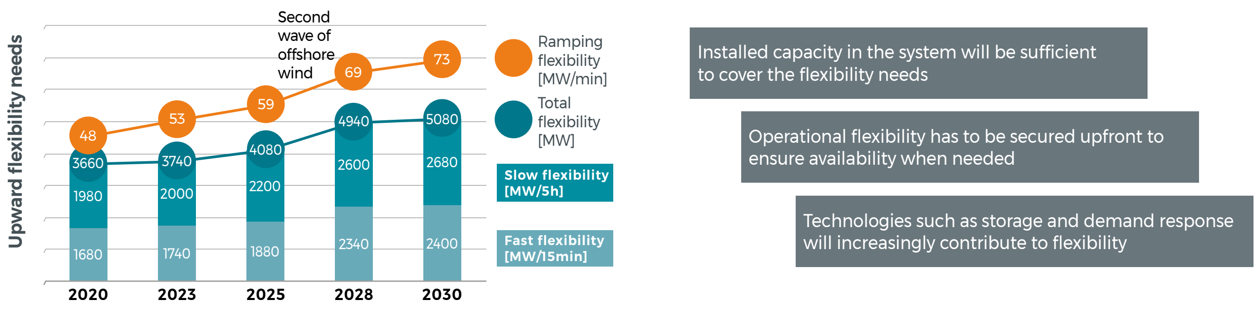


Flexibility needs

Results show that flexibility needs are expected to increase towards 2030 following the further integration of variable renewable capacity such as wind power and photovoltaics. In fact, the new offshore wind power development, with the ambition to achieve 4 GW of installed capacity, is the main driver for these increasing needs. This can be seen on Figure 5-2 representing a synthesis of the upward flexibility needs results (downward follows the same trend but with lower values for the slow and fast flexibility needs).

Increasing needs can be managed by using (more) performant forecast tools. Elia already publishes day-ahead and intra-day forecasts of solar, wind and load and is currently implementing specific offshore forecast tools to help the market to better predict offshore storm cut-outs. Improved forecasts result in a better uptake in day-ahead and intra-day markets and less need for close-to-real-time reserve capacity. However, future prediction accuracy improvements will not fully offset the future increased system flexibility needs induced by the renewable capacity increase. Investigations will be carried out to see if there are technological solutions for offshore wind parks which can help mitigate this impact.

SUMMARY OF RESULTS ON FLEXIBILITY NEEDS AND AVAILABLE MEANS [FIGURE 5-2]



Installed flexibility means

In a system where the adequacy needs are fulfilled, results concerning the available flexibility means (summarised in Figure 5-2) show that in any scenario or sensitivity, and for the time horizon studied, the flexibility needs can be covered with the installed flexibility. This does not mean that any capacity mix will ensure operational availability when needed, or provide this flexibility with the same level of efficiency, but it excludes imposing additional technical requirements concerning flexibility on capacity to cover the adequacy needs.

This conclusion only holds if Elia takes into account the relevant flexibility needs to deal with forced outages and forecast errors during scarcity events. The minimum level is set by the dimensioning incident, i.e. the loss of a nuclear power plant until 2025, or the loss of a HVDC-interconnector to Great Britain. It shows that a capacity of around 1040 – 1240 MW is to be reserved for unforeseen events which can happen after day-ahead market closure.

Operationally available flexibility means

Results of the day-ahead market simulations towards 2030 show that the slow flexibility needs (capacity which can be activated in 5 hours) can always be covered with imports and exports, provided that there is a liquid, well interconnected intra-day market. In contrast, fast flexibility (capacity which can be activated in 15 minutes) and ramping flexibility needs (capacity which can be activated in one minute and can be modulated on a continuous basis) will not always be covered. This requires some kind of reservation mechanism where flexibility is kept available for unexpected variations after the day-ahead market. This reservation can be done by the market keeping flexible assets aside for intra-day and close-to-real-time through adequate price signals, or by Elia reserving capacity for covering residual system imbalances (such as its current contracted balancing capacity).

This is needed for periods during which a limited number of thermal power plants are dispatched, or when energy reservoirs of storage units are nearly empty. Making thermal units available via a reservation mechanism can be costly, particularly for thermal units which must be running at the minimum stable generation level during lower price periods. This may offer for other technologies opportunities - such as demand-side management and storage having a different cost structure (limited fixed costs) - to play an important role in providing the flexibility needed by the system.

Downward fast and ramping flexibility can most of the time be covered by counting on renewable generation management (the current offshore and large onshore wind power plants already demonstrate this capability today). However, towards 2030, a sufficient availability seems less guaranteed as a result of increasing flexibility needs. Therefore, the relevance of technologies which can deal with periods of excess energy and residual load variations such as storage is expected to increase.

In conclusion, adequate price signals are needed on intraday and balancing markets to ensure that market players optimize their investments and operations to achieve an efficient coverage of the system's flexibility needs. This study confirms that new technologies such as storage and demand response will increasingly contribute to covering variations in a renewable electricity system. Elia is currently encouraging this and actively participates in proposals to stimulate this trend. Partly as a result of our initiative, the Internet of Energy project (IO.Energy) was launched at the end of 2018.

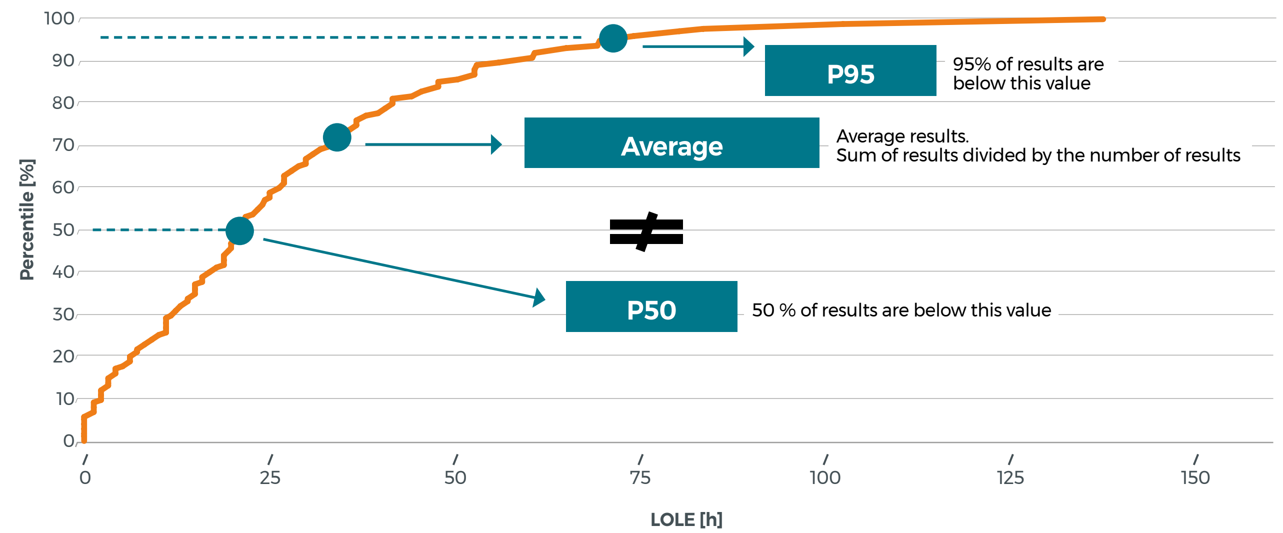
6 Appendixes

A. How to interpret the LOLE criteria

The following indicative Figure 6-1 shows how to interpret the adequacy criteria. Many future states (or 'Monte Carlo' years) are calculated for a given winter or year in a probabilistic assessment (see Section 3.1.3.1). For each future state, the model calculates the LOLE (or 'loss of load') for each winter or year. The distribution of the LOLE among all studied future states can be extracted.

For the first criterion, the average is calculated from all these LOLE results obtained for each future state. 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 (1 chance in 20 of having this amount of LOLE). Both criteria need to be satisfied for Belgium, as specified in the Electricity Act.

EXAMPLE OF A CUMULATIVE DISTRIBUTION FUNCTION OF LOLE [FIGURE 6-1]



Depending on the values of these indicators, four situations can be derived from the results as represented in the table below (see Figure 6-2).

AVERAGE, P95 AND P50 LOLE INDICATORS [FIGURE 6-2]

LOLE average	LOLE P95	LOLE P50	Situation
0	0	0	No LOLE observed 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

Expected Energy Not Served (EENS) [MWh/year or GWh/year] is the average energy not supplied per year by the generating system due to the demand exceeding the available generating and import capacity. In reliability studies, it is common that Energy Not Served (ENS) is examined in expectation over a number of 'Monte Carlo' simulations. To this end, EENS is a metric that measures security of supply in expectation and is mathematically described by (1) below:

$$EENS = 1/N \sum ENS_j \, j \in S \qquad (1)$$

where ENS_j is the energy not supplied of the system state j (j ∈ S) associated with a loss of load event of the j^{th}-Monte Carlo simulation and where N is the number of 'Monte Carlo' simulations considered.

B. Cross border capacity calculation

B.1. 'Flow-Based' versus 'NTC'

'Flow-Based' is a term that englobes methods for capacity calculation which take more accurately the physical grid constraints into account (impedances, physical capacities). On the contrary the so-called Net Transfer Capacity (NTC) approach assumes only one commercial capacity between two market nodes (in each direction). In both the Flow-Based and the NTC, system operational security constraints are respected, fulfilling the N-1 criteria (see Section for more information).

While the NTC method is still used nowadays for capacity calculation on specific borders, the CWE region has moved some years ago towards a 'Flow-Based' method. Currently within the European Capacity Calculation and Congestion Management guideline, the Flow-Based capacity calculation framework is set as the target also for other regions in Europe.

IN NTC:

NTCs are typically calculated by TSOs per border between market areas and provide the maximal commercial capacity to be allocated. TSOs of neighboring market areas coordinate bilaterally to align the NTC values on their common borders. Nevertheless, in a NTC simulation approach each border is treated independently from other borders.

IN 'FLOW-BASED':

The Flow-Based method (FB) instead considers transmission capacity constraints for commercial exchanges between different market areas by considering the physical limits of every individual and relevant critical network element of the grid. The domain of possible commercial exchanges for market coupling is thus not limited by a generalization of exports viewed per border individually (NTC approach), but rather by a set of constraints considering the level of congestions on the critical network elements under normal (N) and grid contingency (N-1) situations. Different commercial exchanges will cause different physical flows on any given branch of the network. Therefore in the FB approach the different exchanges are not independent from each other.

In the next section, a detailed description of the FB method as applied currently in the Central Western Europe (CWE) day-ahead market coupling is presented.

B.2. The CWE Flow-Based operations

The Flow-Based (FB) method implemented in Central Western Europe (CWE) uses Power Transfer Distribution Factors (PTDF) that enable the approximation of real flows through the physical network branches as a result of commercial exchanges between bidding zones.

For each hour of the year, the impact of energy exchanges on each Critical Network Element (also called 'branch'), taking into account the occurrence of network contingencies (N-1), is calculated. The combination of Critical Network Elements and Contingencies (CNEC's) therefore forms the basis of the Flow-Based capacity calculation.

A reliability margin on each CNEC is considered to cover for unexpected flow variations and, where appropriate, 'remedial actions' are also taken into account. These actions can be taken by the TSO, preventively or after an outage has occurred, to partly relieve the loading of the concerned critical network element. Those actions allow to maximize the possible commercial exchanges thanks to changes in the topology of the grid or the use of phase shifting transformers. This procedure finally leads to a set of 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 these domains, 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 for example:

- the grid topology can change;
- outages or maintenance of grid elements can occur;
- the location of available generation units can vary.

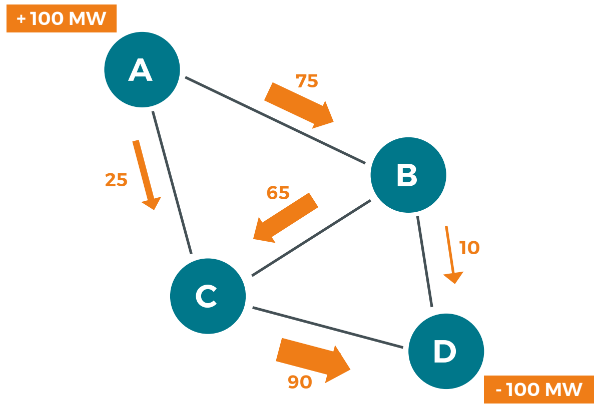
The operational calculation of the FB domain for a given day is started two days before real-time operation and is used to define the limits of energy exchanges between bidding zones for the day-ahead market coupling.

B.2.1. CALCULATION OF NODAL PTDFS

The first step is the calculation of PTDF factors within a given FB geographical area (network parameters and topology are defined).

The PTDF factors estimate (the increase of) the flow that can be expected in the different critical network elements as a function of the injection/extraction of a reference *X* MW between two nodes in the network model.

REPRESENTATION OF A NODAL SYSTEM AND DISTRIBUTION FLOW [FIGURE 6-3]



Let's assume the simplified grid example on Figure 6-3. If an exchange from Node A to Node D of 100 MW occurs, the PTDF factors could be:

- 75% of the injection in Node A goes to Node B and 25% of the injection in Node A goes to Node C;
- 65% of the injection in Node A goes from Node B to Node C and 10% of the injection in Node A goes from Node B to Node D;
- Finally the portion of the total injection in Node A passing through Node C is 25% + 65% = 90%, going to Node D.

The PTDFs thus indicate how the energy flows are (unevenly) distributed over the different paths between the different nodes of the network when the X MW injection/extraction occurs at two points of the network. The distribution given by the PTDFs is determined both by the topology of the grid and the technical characteristics (impedances) of the grid.

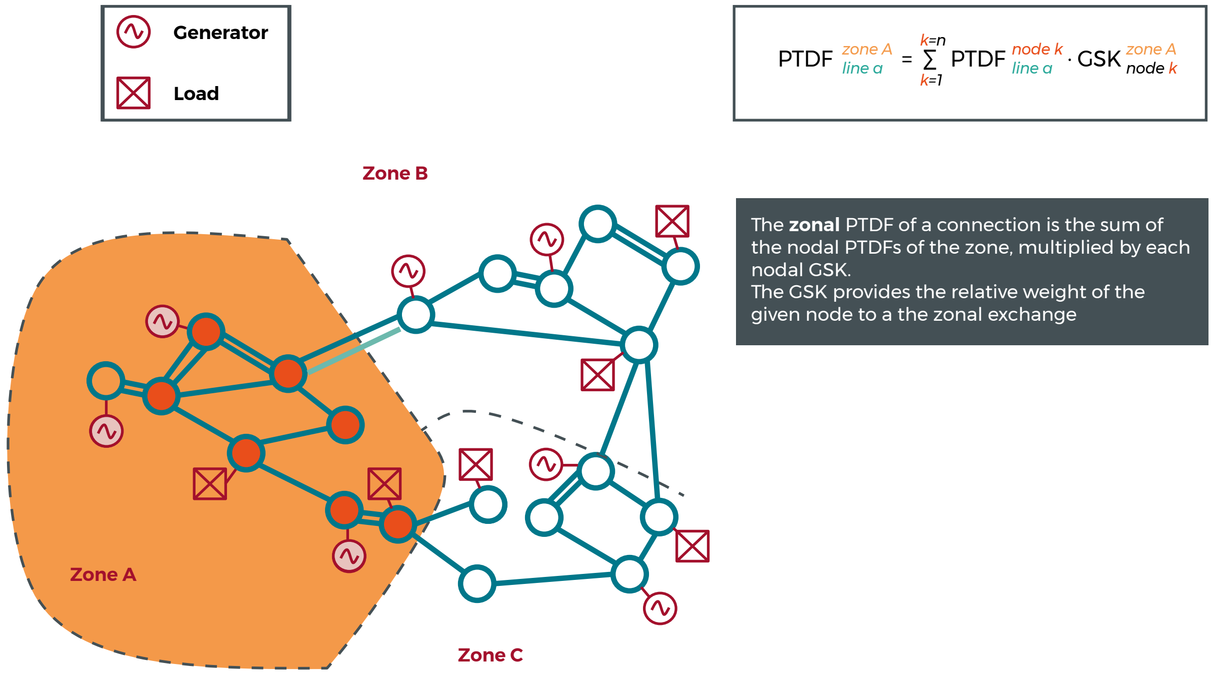
It should be noted that PTDF's are calculated for the flows over the grid elements in N state as well as when grid contingencies occur (see Section).

B.2.2. CALCULATION OF ZONAL PTDFS FROM NODAL PTDFS: APPLYING GSKS

Bidding Zones are defined where all generation and consumption in a given zone have the same wholesale price, hence one 'zonal' PTDF should be defined for the entire bidding zone. Therefore, a mapping is needed between the market 'zonal' level and the grid 'nodal' level, in order to define those 'zonal' PTDFs. In the example below an illustration between the nodal and zonal representation is provided.

A 'zonal PTDF' is needed in order to calculate the effect that a commercial exchange between two market zones, will have on any grid element. The calculation of 'zonal PTDFs' from 'nodal PTDFs' is based on the so-called 'generation shift keys' (GSKs). With this GSK, the nodal PTDF can be converted into a 'zonal PTDF' by assuming that the bidding zone net position is spread among its nodes according to the GSK. Therefore a 'zonal PTDF' is the sum of all 'nodal PTDFs' weighted by their nodal GSK. Below an illustration of this relation between 'zonal PTDFs', 'nodal PTDFs' and GSKs is provided.

CALCULATION OF ZONAL PTDFs [FIGURE 6-4]



$$PTDF^{zone\ A}_{line\ a} = \sum_{k=1}^{k=n} PTDF^{node\ k}_{line\ a} \cdot GSK^{zone\ A}_{node\ k}$$

In this study we consider GSKs on generation units. Within each zone, the GSK can be defined as:

$$GSK_{Zone,Node} = \frac{P^{Nominal}_{Z,N}}{\sum_{N\in Z} P^{Nominal}_{Z,N}}$$

where $\sum_{N\in Z} P^{Nominal}_{Z,N} = NGC^{Z}$ is equal to the installed capacity within the corresponding zone Z and $P^{Nominal}_{Z,N}$ is equal to the installed capacity connected to the node N within zone Z.

These 'pro-rata distribution keys' are an important assumption for the calculation of the zonal PTDFs since, they fix the geographical distribution of generation units at each node N with respect the total installed capacity per type for the given network topology. GSKs therefore fix the weight of each nodal PTDFs into the definition of zonal PTDFs.

B.2.3. CALCULATING THE INITIAL LOADING OF EACH CNEC

The 2-Days Ahead Congestion Forecast (D2CF), provided by each of the participating TSOs in the capacity calculation process for their grid, provides the best estimate of the state of the CWE electric system for day D. This D2CF forecast provides an estimation of:

- the Net Exchange program between the zones;
- the exchanges expected through DC cables;
- planned grid outages, including tie-lines and the topology of the grid as foreseen for D+2;
- forecasted load and its pattern;
- forecasted renewable energy generation, e.g. wind and solar generation;
- outages of generating units, based on the latest generator availability info.

The 'Reference Flow' (F_{ref}) is the physical flow computed from the common D2CF base case and reflects the loading of the Critical Network Elements given the exchange programs of the chosen reference day.

B.2.4. DEFINITION OF REMAINING AVAILABLE MARGIN (RAM) FOR EACH CNEC

For each CNEC, a procedure is followed to calculate the Remaining Available Margin (RAM), which is the physical capacity on the CNEC that can be used by the market coupling algorithm to accommodate cross-border exchanges, as follows:

$$RAM = F_{max} - (FRM + F_0)$$

$$\text{with } F_0 = F_{ref} - \sum_i PTDF_i \cdot NP_i$$

- F_{ref} = Reference flow over the network element in the base grid model where cross-border exchanges are still present;
- NP_i = Net position (Balance) of Bidding Zone "i" of CWE in the Reference situation;
- $PTDF_i$ = Zonal PTDF of bidding zone "i" for the considered branch;
- F_0 = Flow over the network element when cross-border exchanges within the CWE zone are cancelled;
- FRM = Flow Reliability Margin, used by TSOs to account for the uncertainty due to forecast errors;
- F_{max} = The maximal allowable physical flow over the concerned branch in order to comply with operational and material limits.

An important factor determining the final RAM is therefore the 'initial flow' F_0, reflecting the flow over the network element when all zones within CWE are at zero balance. This flow includes:

- The flows resulting from internal exchanges in the bidding zone where the CNEC is located (mostly relevant for CNEC's within a bidding zone, much less for cross-border (XB) CNECs);
- The flows resulting from internal exchanges in other Bidding Zones than the one where the CNEC is located (loop flows);
- The flows resulting from capacity allocation outside CWE (transit flows).

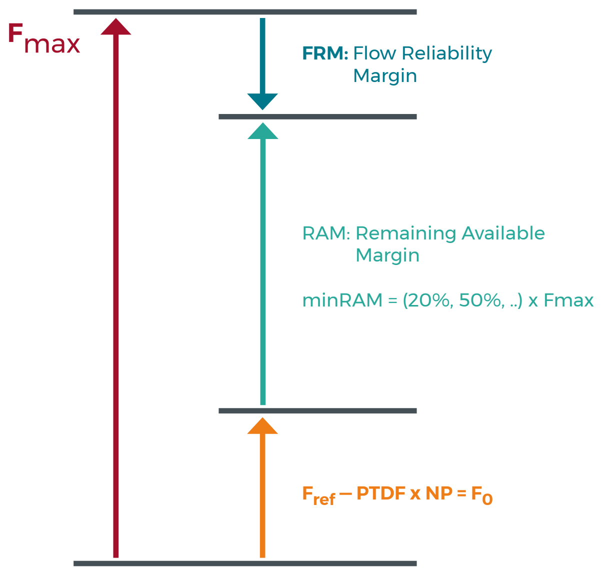
Thus the FB market coupling process starts at the so called 'zero balance' point. This is the point in which there are no commercial exchanges between bidding zones within the FB Capacity Calculation Region (CCR) under consideration (CWE, CORE[1], etc..), and where only flows due to internal exchanges, loop flows and transit flows are present in the network.

The RAM can finally be subjected to a minimum threshold, also referred to as MinRAM. In 2018, CWE implemented a 20% minimum Remaining Available Margin (MinRAM20%) for the day-ahead Flow-based Market Coupling (FBMC). The agreed MinRAM20% level equals 20% of the F_{max} (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 (system security check). The go-live of the MinRAM20% implementation was on 24 April 2018 in D-2 (for FBMC Business Day 26 April 2018).

New requirements within the Clean Energy Package (CEP) (see Section 2.7.4) regulation impose that 'at least 70% of the Fmax should be provided as capacity for internal and cross-border CNECs'. It is important to note that the "minimum" value of 70% refers to the available capacity for all cross-zonal exchanges, which involves capacity offered for cross-zonal exchanges within the given CCR (CWE, CORE, etc..) and the capacity for cross-zonal exchanges in and between other CCRs (i.e. transit flows).

The illustration below summarises the approach:

DEFINITION OF REMAINING AVAILABLE MARGIN (RAM) [FIGURE 6-5]



N - 1 criterion

If an element fails, for example a high-voltage line, the energy transported by that element is immediately transferred to the neighboring elements. The N-1 criterion imposes that in the case of a failure or contingency, such transfer may not cause overloads in the network. This is important to avoid that a chain reaction arises and, by extension, the network stability of the entire European network can be endangered.

The capacity calculation should therefore ensure that the capacity offered to the market is maximized while the N-1 criteria is ensured at all times. The calculation of the PTDF and RAM therefore accounts for the N-1 principle.

1. CORE= [AT, BE, CZ, DE, FR, HR, HU, LU, NL, PL, RO, SI, SK].

B.2.5. CALCULATING THE FB CAPACITY DOMAIN

Figure 6-5 shows how the FB domain can be determined by combining the calculated remaining margins (RAM) and the zonal PTDFs for each relevant Critical Network Element and Contingency (CNEC) pair. The first constraint is determined for line 1, in a situation without contingencies. We draw from the table that the CNEC has a RAM of 150 MW, a zonal PTDF for zone A of -30%, for zone B of 25% and for zone C of 10%. The same exercise is now performed for all other line and contingency pairs, ultimately resulting in a collection of constraints (RAM, $PTDF_A$, $PTDF_B$, $PTDF_C$).

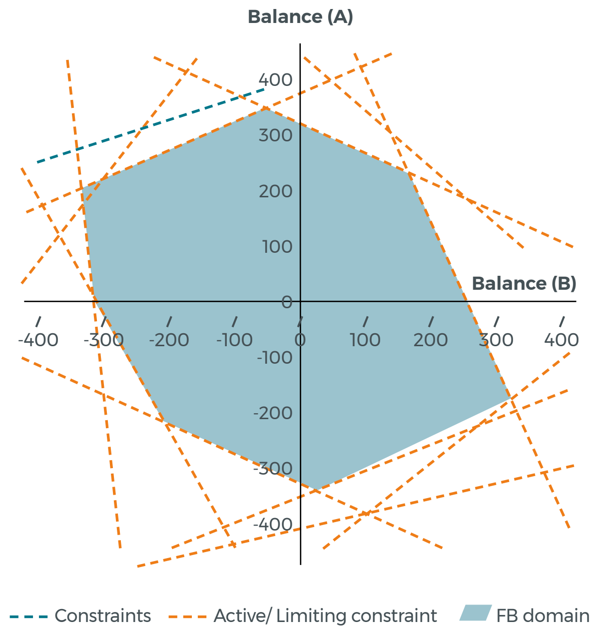
These constraints can be understood as geometrical planes in the dimensions defined by the balances of the difference zones: Balance(A), Balance(B), etc. For the purpose of illustration, the constraints can be plotted between two balances as the projection of these planes will be reduced to lines. Figure 6-6 depicts such projection for Balance (A) vs Balance (B), where the constraints are represented by the grey dotted lines. Generally the convention is used where positive balances represent net exports and negative balances represent net imports.

As a final step, the total set of constraints can be reduced by removing all non-relevant constraints. Constraints are considered non-relevant when other constraints are always reached earlier. This procedure is also called 'pre-solving' the domain, and leads to the final combination of relevant constraints forming the secure domain, colored in yellow in Every combination of secure exchanges between all different zones is part of this domain.

INITIAL FB CAPACITY DOMAIN CALCULATION [FIGURE 6-5]

CRITICAL NETWORK ELEMENTS	INCIDENT	REMAINING AVAILABLE MARGIN (MW)	INFLUENCE OF THE EXCHANGE ON EACH LINE (PTDF)		
			A	B	C
Line 1	No incident	150	-30%	25%	10%
	Incident 1	120	-17%	35%	-18%
	Incident 2	100	15%	30%	12%
Line 2	No incident	150	60%	25%	25%
	Incident 3	50	4%	-15%	4%
Line 3	No incident	-	-	-	-
	Incident 4	-	-	-	-

EXAMPLE OF FB CAPACITY CALCULATION [FIGURE 6-6]



B.3. The 'mid-term flow-based' modelling framework used in this study

As described in the previous section, the flow-based capacity calculation is a complex process involving many stakeholders and many parameters. To build market models where market exchanges adhere to the rules depicted in a flow-based coupled market, multiple approaches are possible. For short term forecasts and analyses, a framework relying on the flow-based domains conceived in the SPAIC process was developed [JAO-1]. This framework however leans heavily on historical data. As historical domains are strongly related to the historical grid & generation situation this approach is not suited for studies on a longer time horizon where significant evolutions on the grid and generation mix occur.

Elia has developed a mid-term flow-based framework which does not rely on historical domains, but instead aims to mimick the operational flow-based capacity calculation workflow, for which the required inputs are forecasted for the targeted time horizons.

B.3.1. CALCULATION OF PTDFS

The first step of the mid-term flow-based framework is the definition of a set of PTDFs[2]. To obtain those, a European grid model is built, which is for this study based on the TYNDP 2018 reference grid, upon which grid modifications for Belgium are applied at the different target time horizons. This grid model is then used to calculate the PTDFs.

A PTDF matrix consists of lines/rows representing the different CNEC's that are taken into account, and columns representing the variables in the flow-based domain.

- Each CNEC refers to the combination of a Critical Network Element and a Contingency. In the grid model that was used for this study, many hundreds of CNECs were considered;
- The variables can represent the net positions of the grid nodes under consideration, the HVDC[3] flows, PST positions, etc; depending on the degrees of freedom that are given to the market coupling algorithm.

Aside from a PTDF matrix, the flow-based mid-term framework also requires the capacity of each Critical Network Element. These correspond to the steady-state seasonal ratings of the network elements.

2. A PTDF coefficient for a CNEC & zone represents the change in flow on the CNEC related to the change in net position of the zone (see Section).

3. An HVDC link is a controllable device by nature. Power electronics allow for completely control the flow on the link, therefore not making it subject to Kirchhoff laws.

B.3.2. CALCULATING THE INITIAL LOADING OF EACH CNEC

For this study, to be in line with current market operations, only CWE is modelled as a flow-based region. The variables are the net positions of the countries (BE, DE (and LU), NL, FR, AT) toward CWE. Flows outside of CWE are subject to NTC constraints, and the interaction between the flow-based region and flows on external borders to CWE are modelled using standard hybrid coupling. Only cross-border (XB) CNECs are considered for the 5 CWE countries. ALEGrO is modelled using 'evolved flow-based', introducing a 6th variable in the PTDF matrix.

As described in Section 2.7.2, once fully set up, the mid-term flow-based framework first performs a market dispatch simulation to determine the initial loading of each CNEC. In this simulation, 2/3rd of the PST tap ranges are allowed to be used to optimize initial flows in order to maximize welfare of the system. The flows from this simulation determine the "Reference Flows (F_{ref})" (see Section,). These flows are then scaled back to zero-balance flows "F_0" per Bidding Zone through the use of GSKs. This procedure mimicks the CACM CC process and allows for a good estimation of the pre-loading on CNECs.

B.3.3. CALCULATING THE FB CAPACITY DOMAIN

European legislation requires minimum margins to be made available to the market. For this reason, every time a CNEC's margin after preloading is less than the required minimum margin given to the market, the minimum margin is guaranteed (see also Section 2.7.2).

B.3.4. CLUSTERING OF DOMAINS

In this study, a series of climatic years is used to model variability in climatic variables such as renewable generation, electricity demand... The use of hourly domains for the market simulations is however not deemed computationally efficient. The calculated hourly domains were therefore clustered into groups, identifying one representative domain per group. Furthermore, the relationship between each group and the climate conditions was analysed in order to map them onto the model. This approach is line with what is done in the strategic reserve volume determination assessments.

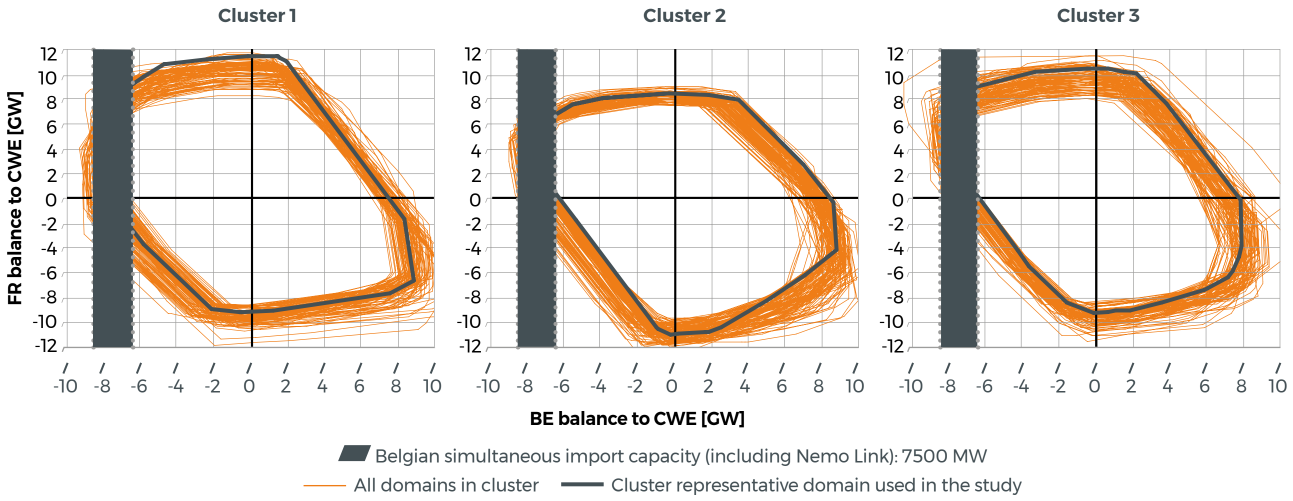
For this study, and after analyzing multiple combinations of pre-clustering data split (seasonal split, day type split, ...) no clear trends were identified therefore the decision was made not to apply any pre-clustering data split, but to cluster the entire set of 8760 domains as a whole. Indeed, no clear advantage in the distinction of domains using pre-cluster splits was found, as higher winter initial flows are offset by higher steady-state seasonal ratings of the network elements.

APPENDIXES

Each flow-based domain is a 6 dimensional shape, one dimension for each of the 6 variables. The clustering of the 8760 domains is based on their geometrical shape. For this it is important to define a good distance metric between domains. Next, one needs to define the number of clusters to retain. For this study, all domains were clustered into three groups. An advantage of choosing a low number of clusters is that many domains are present in each of the clusters, therefore reinforcing the stability of the chosen medoid. After defining the number of groups, a representative domain per group is chosen. This is done by means of a k-medoid algorithm. Here the medoids are elements which are part of the initial domains, and therefore have physical meaning.

The quality of the clustering can be visually observed by plotting all domains for each cluster, as well as the centroid, as is shown in For each of the clusters a correlation analysis with climatic variables (in this case CWE load & wind) was performed. Based on this analysis French load & German wind infeed were identified as the main axes to which the clusters can be correlated. for 2025.

THE GROUPING OF DOMAINS PER CENTROID SHOWS THE QUALITY OF THE CLUSTERING ALGORITHM (EXAMPLE SHOWN FOR 2025) [FIGURE 6-7]



For each of the clusters a correlation analysis with climatic variables (in this case CWE load & wind) was performed. Based on this analysis French load & German wind infeed were identified as the main axes to which the clusters can be correlated.

EXAMPLE OF THE CORRELATION BETWEEN GERMAN WIND AND CLUSTER FOR THE CLUSTERS USED IN THIS STUDY ON THE 2025 HORIZON [FIGURE 6-8]

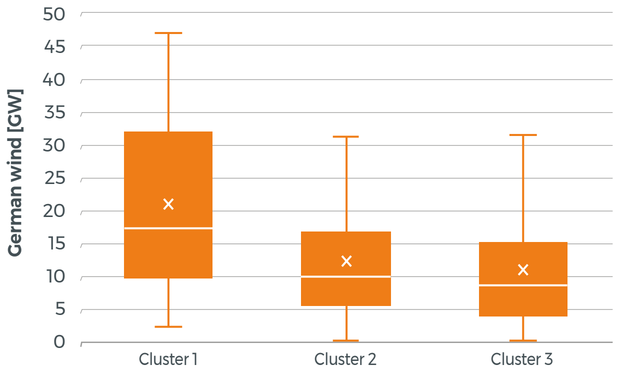


Figure 6-8 shows the occurrence of each cluster for different German wind conditions. A few observations can be made from the figure: :

- For a range of wind infeed in Germany between 10 GW and 25 GW (y-axis), a significant overlap is observed between the three different clusters. This means that within this range, each of the three clusters can be associated to the given level of wind infeed in Germany, each still with a different probability of occurence. Therefore a fully deterministic linking of a each cluster to a certain threshold of German wind infeed is not possible. The same is generally true for the French load correlation.
- The second observation is however that the size of the boxplots above is not equal indicating e.g. that cluster 1 will have a relative higher probability of apparence in the high range of wind infeed (~15 GW-23 GW), whereas cluster 3 will have a relative higher probability of appearence in the range of low wind infeed, below 5 GW.

Therefore, both climatic variables wind infeed in Germany and French load were split into three groups (threshold defined by the 33% and 66% percentiles) and for each of the possible nine combinations a probability of finding cluster 1, 2 or 3 is calculated. These probabilities for each of the nine combinations are shown in Figure 2-55.

B.3.5. STOCHASTIC CHOICE OF DOMAIN DEPENDING ON CLIMATE CONDITIONS

The flow-based domains are now ready to be applied to the final market model. The flow-based constraints are transferred onto the model as additional constraints of the global optimisation problem. For each 'Monte Carlo' year, the related climatic year will define the French load & German wind. These values define which of the 9 climatic groups is active for any given hour. For each climatic group, the probabilities of finding a specific cluster are defined as mentioned above, and so a sample of the centroids is drawn adhering to these probability rates.

C. Adequacy Patch

C.1. Implementation in EUPHEMIA

Within the EUPHEMIA algorithm (PCR Market Coupling Algorithm [NSI-1]), a mitigation measure has been implemented to prevent price-taking orders (orders submitted at the price bounds set in the market coupling framework) to be curtailed because of "flow factor competition".

The solution implemented in EUPHEMIA within Flow-based market coupling (FBMC) follows the curtailment sharing principles that already existed under ATC/NTC. The objective is to equalize the ratio of curtailment between bidding zones as much as possible.

C.2. Flow factor competition

If two possible market transactions generate the same welfare, the one having the lowest impact on the scarce transmission capacity will be selected first. It also means that, in order to optimize the use of the grid and to maximize the market welfare, some sell (/buy) bids with lower (/higher) prices than other sell (/buy) bids might not be selected within the flow-based allocation. This is a well-known and intrinsic property of flow-based referred to as 'flow factor competition'.

C.3. Flow factor competition and price taking orders

Under normal FBMC circumstances, 'flow factor competition' is accepted as it leads to maximal overall welfare. However for the special case where the situation is exceptionally stressed e.g. due to scarcity in one particular zone, 'flow factor competition' could lead to a situation where order curtailment takes place non-intuitively. This could mean e.g. that some buyers which are ready to pay any price to import energy would be rejected while lower buy bids in other bidding areas are selected instead, due to 'flow factor competition'. These 'pay-any-price' orders are also referred to as 'Price Taking Orders', which are valued at the market price cap in the market coupling. This would lead to the situation where one bidding area is curtailed while the clearing prices in the other bidding areas are lower (below market price cap). This is the situation that the adequacy patch seeks to mitigate by by-passing flow factor competition in such cases and ensuring maximal imports for zones experiencing curtailment.

C.4. Curtailment sharing

The situation becomes more complex when two or more markets are simultaneously in curtailment. For these situations, the mechanism put in place aims to 'fairly' distribute the curtailments across the involved markets by equalizing the curtailed price-taking orders to total price-taking orders ratio between the curtailed zones.

The curtailment sharing is implemented by solving a sub-optimization problem, where all network constraints are enforced, but only the acceptance of the price taking volume is considered in the objective function. The curtailment ratios weighted by the volumes of price taking orders are therefore minimized (see EUPHEMIA public description for [EPE-1]).

D. 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 [RTE-2].

Grid topology

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

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

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

Wind and solar generation

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

Thermal generation

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

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

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

Hydro generation

Three categories of hydro plants can be used:

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

E. Simulation of the electricity market

This appendix provides a general overview of how the simulation of the electricity market was conducted for this analysis. First the tool used to perform the simulations is introduced in section . Next, the way the market simulations are conducted is detailed. Inputs for the simulations are introduced as well as how they are used in the constructions of the 'Monte Carlo' years.

E.1. Antares – a model used to simulate the electricity market

The market simulator used within the scope of this study is ANTARES[1] [RTE-2], 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:

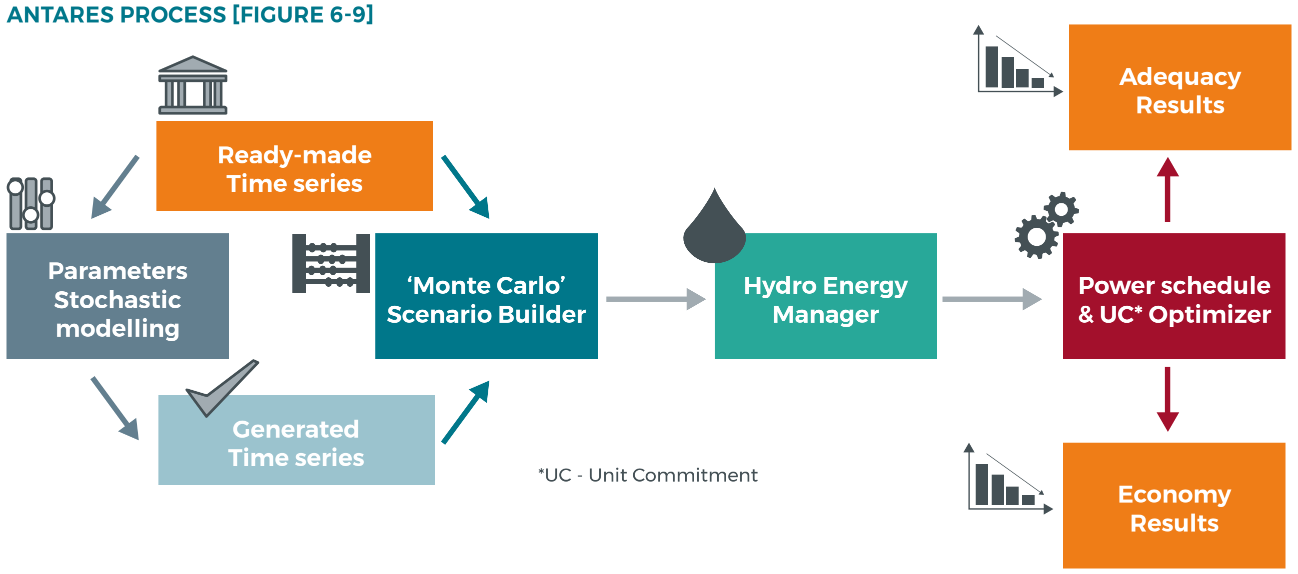
- representation of several interconnected power systems through simplified equivalent models. The European electrical network can be modelled with up to a few hundred of region-sized or country-sized nodes, tied together by edges whose characteristics summarise those of the underlying physical components;
- 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 E.2.3).

ANTARES PROCESS [FIGURE 6-9]



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

STEP 1: CREATION OF ANNUAL TIME SERIES FOR EACH PARAMETER

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

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 3-4.

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. It is also possible to draw outages on other type of units or technologies such as HVDC links or storage facilities.

Note that for adequacy studies ,as it will be described in Section E.2.3., 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, hydro-electric production and thermo-sensitive consumption is performed for a given year, coming from one of the historical weather scenarios.

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) [RTE-2]. 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, demand response 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.

Besides Elia adequacy studies, the model is used in many European projects and national assessments:

- The MAF adequacy study (ENTSO-E) published every year around October [ENT-1];
- the PLEF adequacy study published in 2018] and the next version which is expected for publication end of 2019 (after the MAF report);
- the e-Highway2050 study [EHW-1];
- the osmose project [OSM-1];
- ENTSO-E's TYNDP [ENT-2];
- The Belgian Federal Network Development Plan [ELI-9];
- RTE French Generation Adequacy Reports [RTE-1] including long term, mid term and seasonal analysis;
- The Global Grid study within CIGRE [GLO-1].

E.2. 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. This section begings by indicating which variables are taken into account (Section). Next, modelling of electricity production is illustrated (Section E.2.2). Finally, Section E.2.3 elaborates on how the different variables are combined into 'Monte Carlo' years.

E.2.1. 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/solar generation;
- daily time series for temperature (these can be used to calculate the hourly time series for electricity consumption);
- hydro inflows resulting from rain and ice melts.

However, two variables are **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;
- parameters relating to the **availability of HVDC links** (excluding those within a meshed grid) on the basis of which samples can be taken regarding their availability.

BOX 16: 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 6-10 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 34 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:

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 generation. This is a logical result from the fact that more solar generation goes on during the summer and inter-season months;

When the level of wind energy production is very high, the level of PV generation tends to fall;

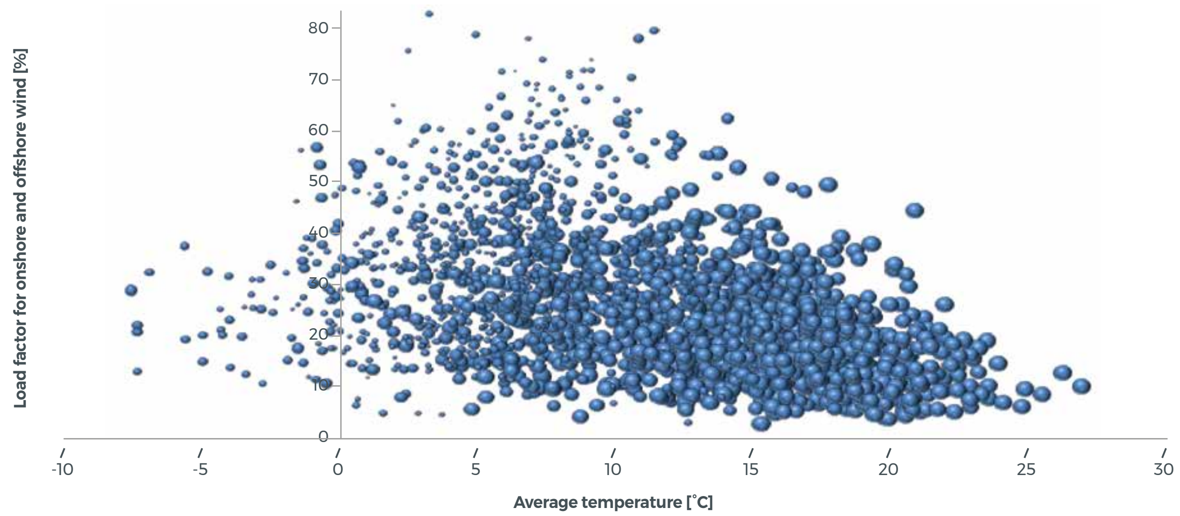
In extremely cold periods, wind energy production falls while there is a slight increase in PV generation. This is a key finding that will affect adequacy during very cold weather.

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.

CORRELATION BETWEEN WIND PRODUCTION, SOLAR PRODUCTION AND TEMPERATURE (AVERAGE OF 7 DAYS) [FIGURE 6-10]

The graph is built based on the climatic years considered in this study. Each bubble on the chart relates the wind production to the average temperature. The size of the bubble is a measure for the solar production in those same 7 days.



The climatic variables in this study are modelled on the basis of 34 historical years (which result in 33 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 and the ENTSO-E TYNDP market simulations.

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

VARIABLES - CORRELATION BETWEEN WIND PRODUCTION, SOLAR PRODUCTION AND TEMPERATURE (AVERAGE OF 7 DAYS) [FIGURE 6-11]

Sunshine hours, temperature	→	Hourly solar production
Hourly wind speed	→	Hourly wind production
Monthly hydraulic production	→	Hourly production decided by the model by minimizing the cost of the system
Daily temperature	→	Hourly consumption taking into account the thermosensitivity
Probability and duration of failure	→	Random selection by the daily availability chronic model

Other variables (see below) might have a potential impact on security of supply but given their nature are disregarded in from the variables of the 'Monte Carlo' simulation. However, some events listed below are taken into consideration in this study by means of additional unavailability of units.

The Monte-Carlo simulations performed in this study disregard, the following events (this list is not meant to be exhaustive):

- long-term power plant unavailability (sabotage, political decisions, strikes, maintenance due to additional inspections, bankruptcy, terrorist attacks, etc.). Those events are assessed separately by additional unavailability of units (on top of the one drawn by the 'Monte-Carlo' simulation);
- interruption of the fuel supply or cooling of the power plants (low water levels, heatwave, ...);
- extreme cold freezing water courses used for plant cooling;
- natural disasters (tornadoes, floods, etc.).

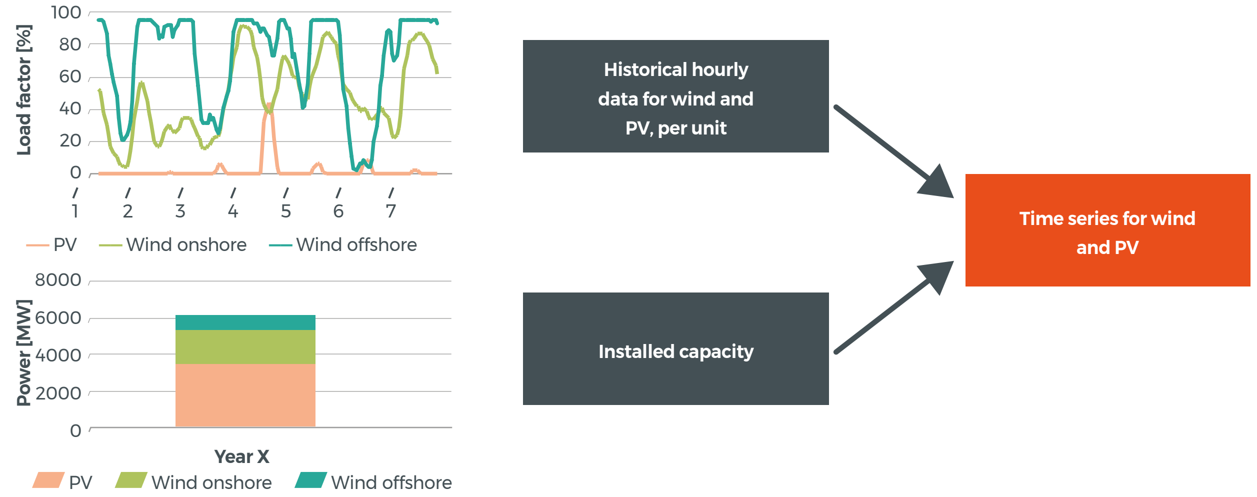
E.2.2. MODELLING OF ELECTRICITY GENERATION

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

E.2.2.1. Wind and solar electricity production

As already indicated in Section , 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 6-12.

PRODUCTION TIME SERIES FOR WIND AND PV [FIGURE 6-12]



E.2.2.2. Individually modelled thermal production

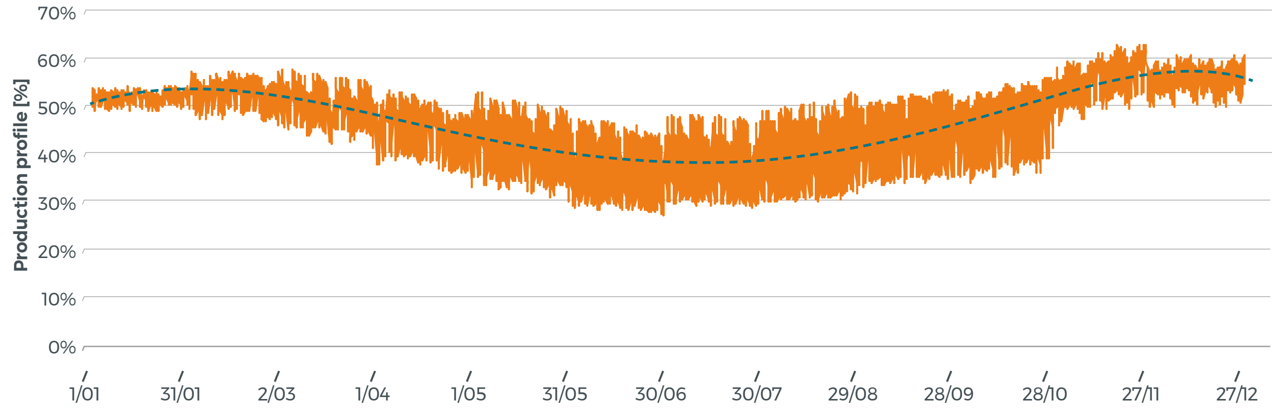
Large thermal generation units, independent of their generation types, are modelled individually, with their specific technical and economic characteristics. Their individual availability is determined by a probabilistic draw for each 'Monte Carlo' year (see Section) based on historical availability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

E.2.2.3. 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 6-13. This profile was also made public in the public consultation on the data used in this analysis.

HOURLY AVERAGE NORMALISED PROFILED THERMAL PRODUCTION OVER 33 CLIMATIC YEARS [FIGURE 6-13]



E.2.2.4. Hydroelectric power production

Three types of hydroelectric power production are taken into account:

- pumped storage;
- run-of-river;
- inflow reservoir power production.

The first two types of hydroelectric power production are present in Belgium, whilst the last type is more common in countries with more natural differences in elevation.

Pumped-storage power production 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. An efficiency for the round-trip process of 75% is taken into account in the modelling. Depending on the size of the pumped storage reservoirs as well as their operating mode, their dispatch can differ. The model differentiates between pumpedstorage production units which optimise their dispatch on a daily basis and those which optimise their dispatch on a weekly basis.

A more classic form of hydroelectric power production converts energy of a natural water flow 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 into the simulation model, together with their inflows. If no reservoir is present, the production 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.

E.2.3. 'Monte Carlo' sampling and composition of climatic years

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

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

In contrast, for power plant and HVDC link 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 and HVDC links 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.

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.

E.3. 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 2, Sections 2.6.3, 2.6.4, 2.6.5 and 2.6.6 elaborate on the scenarios and assumptions 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)).

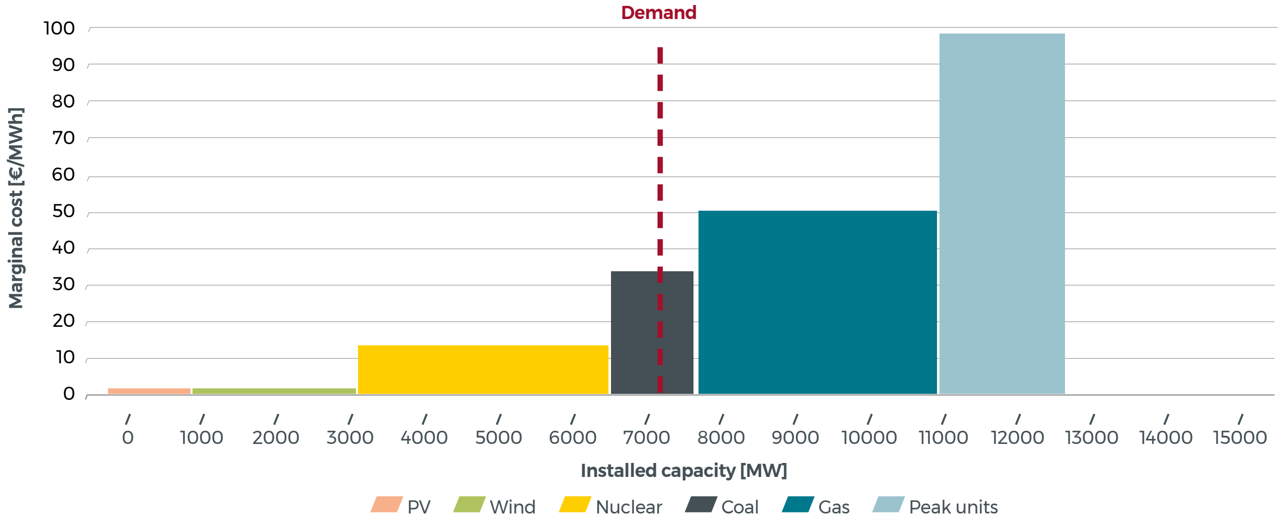
These data are introduced by means of hourly or monthly time series or are established for a whole year.

A detailed modelling of the power plants' economic dispatch is performed. The assessment takes into account the power plants' marginal costs (see Figure 614) and also enables the pumped-storage power plants and hydroelectric reservoirs to be appropriately modelled (see Section).

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 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.

EXAMPLE OF AN ECONOMIC STACK FOR A GIVEN TIME AND A GIVEN PRODUCTION PARK [FIGURE 6-14]



The **output of the model** that is assessed in this the adequacy assessment 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:

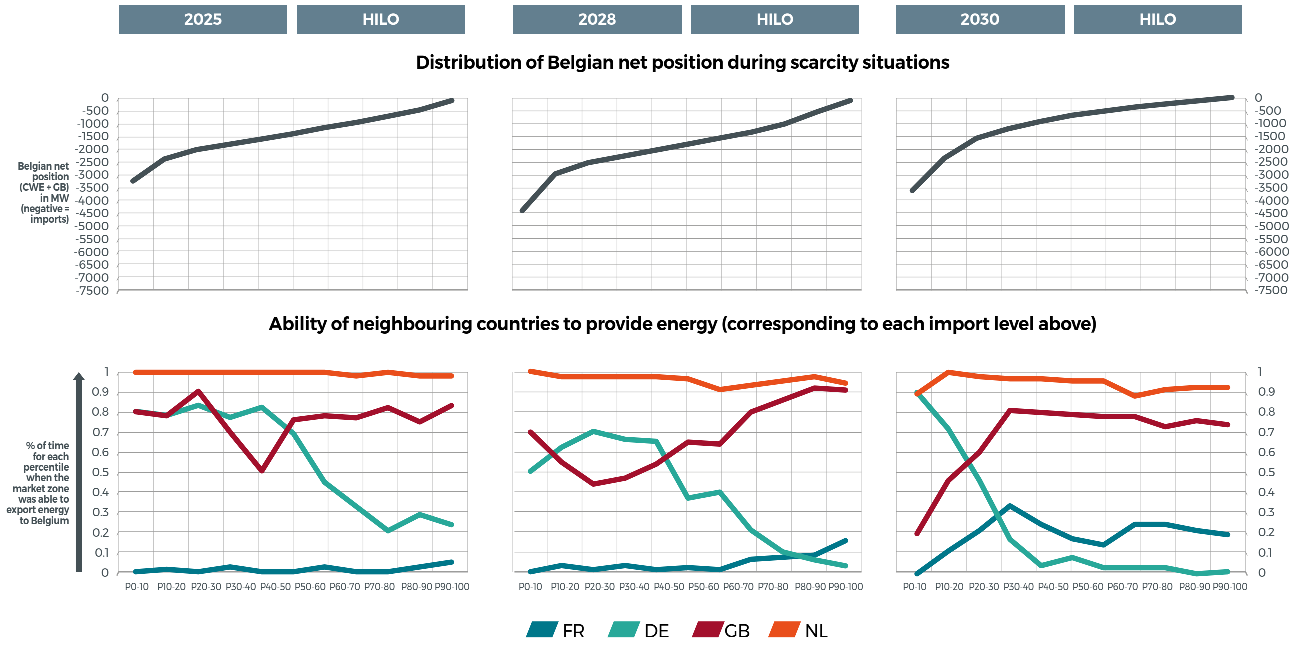
- the countries' energy balance (exports/imports);
- the use of commercial exchanges;
- the number of operating hours and revenues of the power plants;
- CO_2 emissions;
- the hourly marginal price for each country.

F. Additional results on adequacy

F.1. Detailed analysis of imports during scarcity events

EU-HILO SCENARIO

NET POSITION OF BELGIUM (CWE + GB) DURING SCARCITY AND CAPABILITY OF OTHER COUNTRIES TO EXPORT ENERGY DURING THOSE MOMENTS [FIGURE 6-15]



G. Additional results on flexibility

G.1. Flexibility needs (based on a 99.9% percentile)

[FIGURE 6-16]

NEW LARGE-SIZED UNITS

UP	CENTRAL			N-PRO			IHS-DEMAND			LOW DEMAND			HIGH RES			LOW RES		
	TF	FF	RF	TF	FF	RF	TF	FF	RF	TF	FF	RF	TF	FF	RF	TF	FF	RF
2020	3660	1680	720	3660	1680	720	3660	1680	720	3660	1680	720	3660	1680	720	3660	1680	720
2023	3740	1740	800	3740	1740	800	3740	1740	800	3740	1740	800	3900	1800	840	3580	1660	740
2025	4080	1880	880	4100	1880	880	4080	1880	880	4060	1860	880	4620	2160	1000	3760	1720	760
2028	4940	2340	1040	4940	2340	1040	4940	2340	1060	4900	2320	1040	5500	2620	1180	4540	2180	980
2030	5080	2400	1100	5080	2400	1100	5120	2420	1100	5100	2420	1100	5880	2780	1280	4560	2180	960

NEW SMALL-SIZED UNITS

UP	CENTRAL			N-PRO			IHS-DEMAND			LOW DEMAND			HIGH RES			LOW RES		
	TF	FF	RF	TF	FF	RF	TF	FF	RF	TF	FF	RF	TF	FF	RF	TF	FF	RF
2020	3660	1680	720	3660	1680	720	3660	1680	720	3660	1680	720	3660	1680	720	3660	1680	720
2023	3740	1740	800	3740	1740	800	3740	1740	800	3740	1740	800	3900	1800	840	3580	1660	740
2025	3920	1840	880	4000	1860	880	3920	1840	880	3920	1840	880	5420	2140	1000	3520	1660	760
2028	4820	2320	1040	4860	2320	1040	4840	2320	1060	4820	2320	1040	5440	2600	1180	4360	2140	980
2030	4980	2380	1100	5000	2380	1100	5000	2380	1100	4980	2380	1100	5840	2780	1280	4380	2140	960

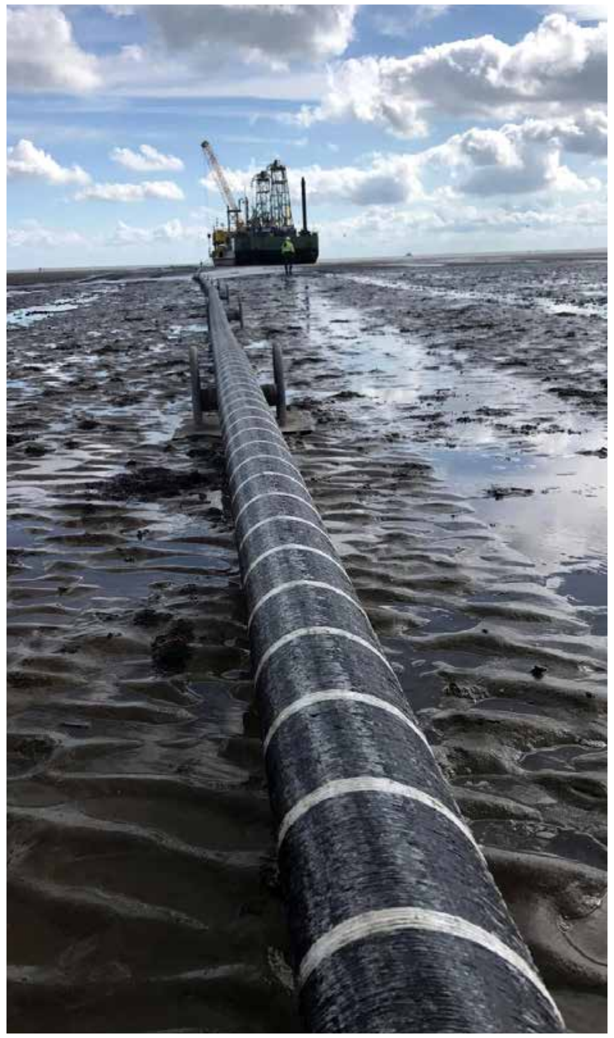
NEW LARGE- OR SMALL-SIZED UNITS

DOWN	CENTRAL			N-PRO			IHS-DEMAND			LOW DEMAND			HIGH RES			LOW RES		
	TF	FF	RF	TF	FF	RF	TF	FF	RF	TF	FF	RF	TF	FF	RF	TF	FF	RF
2020	3080	1380	840	3080	1380	840	3080	1380	840	3060	1380	840	3080	1380	840	3080	1380	840
2023	3220	1440	880	3220	1440	880	3220	1440	880	3220	1440	880	3380	1520	920	3080	1380	840
2025	3400	1540	920	3400	1540	920	3420	1540	940	3400	1540	920	3920	1820	1040	3120	1400	860
2028	4240	2000	1180	4240	2000	1180	4280	2020	1180	4240	2000	1180	4660	2180	1300	3920	1840	1080
2030	4340	2040	1220	4340	2040	1220	4380	2060	1220	4340	2040	1220	4960	2320	1360	3940	1860	1080

G.2. Flexibility needs during periods with scarcity risk (based on a 99.9% percentile)

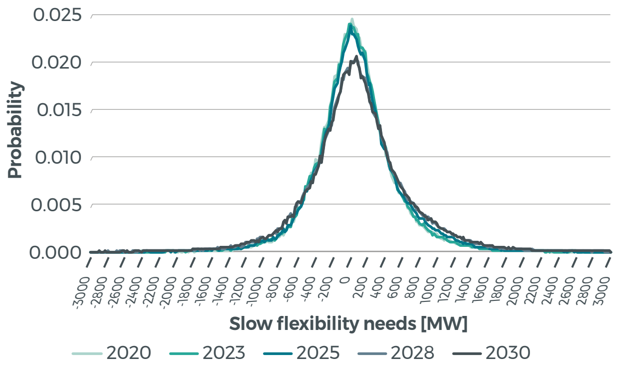
[FIGURE 6-17]

	NEW LARGE-SIZED UNITS				NEW SMALL-SIZED UNITS			
	CEN-TRAL	N-PRO	HIGH RES	LOW RES	CEN-TRAL	N-PRO	HIGH RES	LOW RES
2020	1160	1160	1160	1160	1160	1160	1160	1160
2023	1100	1100	1100	1100	1100	1100	1100	1100
2025	1140	1180	1180	1120	1000	1100	1020	1000
2028	1240	1260	1260	1220	1040	1180	1060	1040
2030	1240	1260	1260	1220	1040	1180	1060	1040

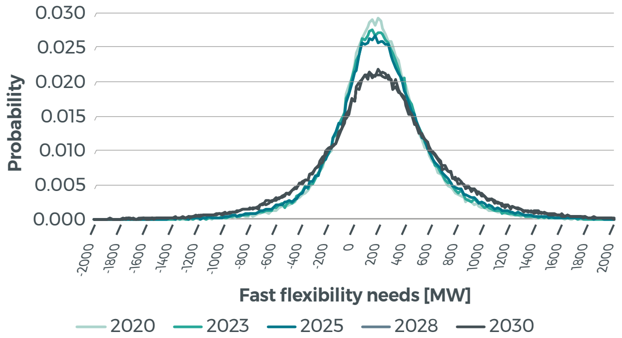


G.3. Probability distributions of the flexibility needs in the CENTRAL scenario

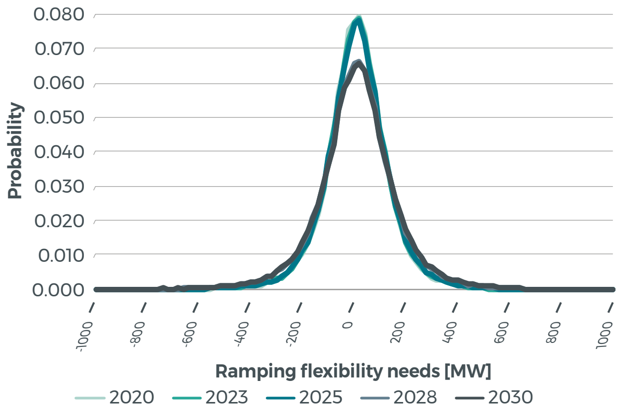
[FIGURE 6-18]



[FIGURE 6-19]



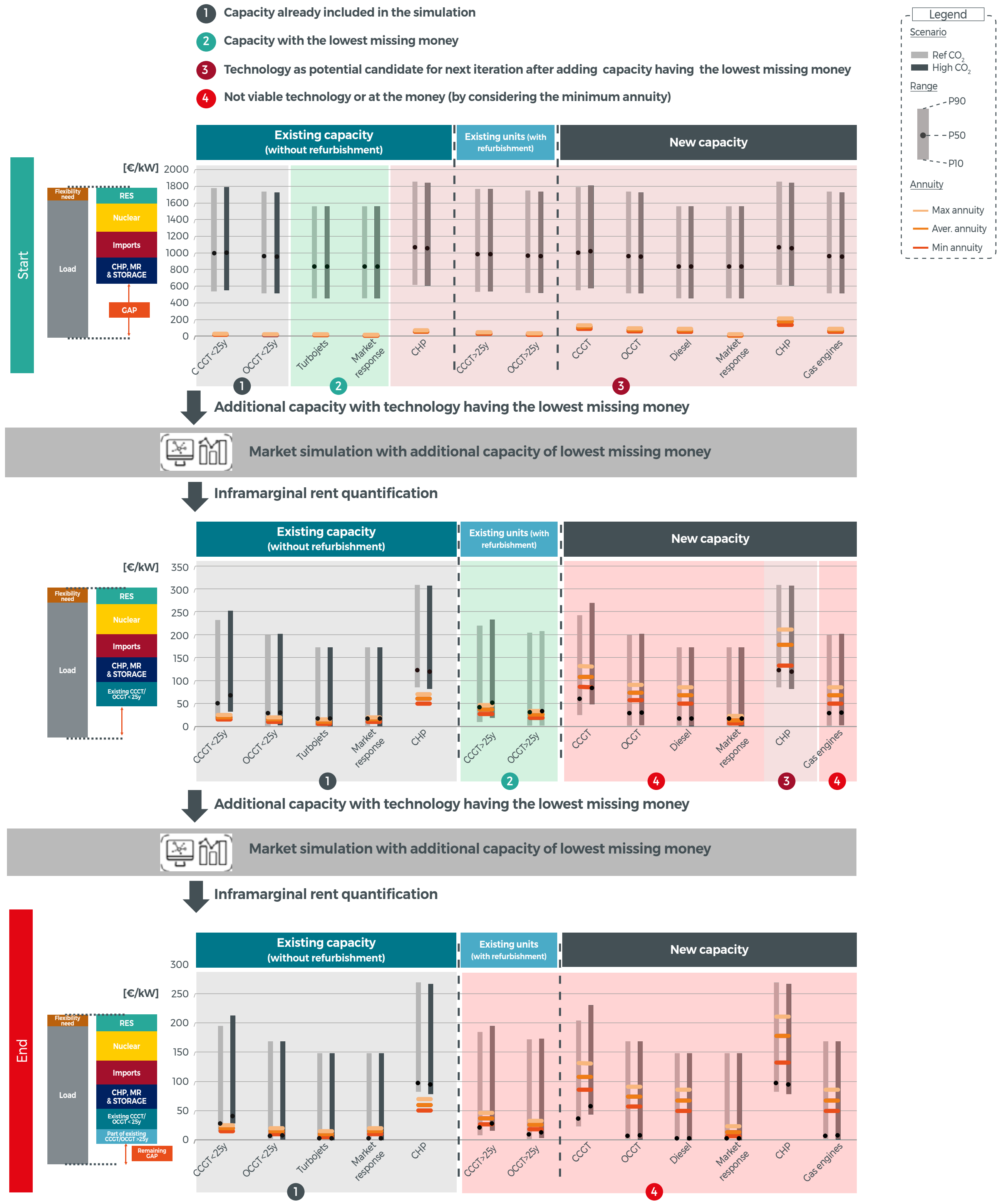
[FIGURE 6-20]



H. Additional results on economics

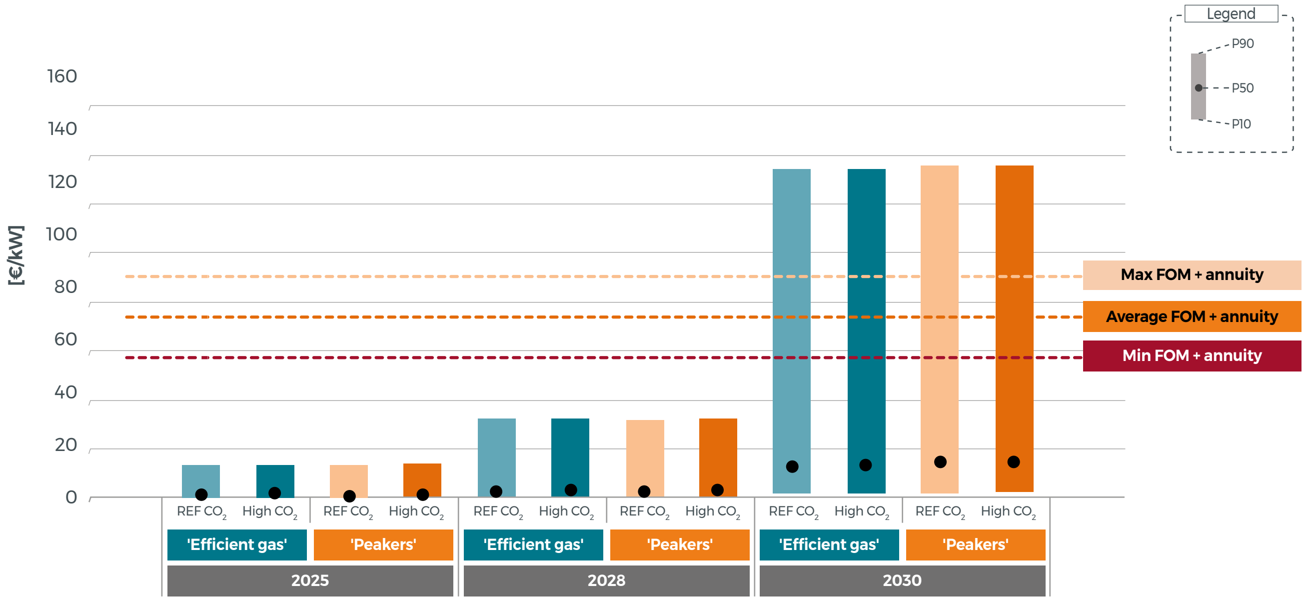
H.1. Economic viability process

INFRAMARGINAL RENT FOR EXISTING UNITS AND NEW CAPACITY IN CENTRAL SCENARIO FOR 2025 [FIGURE 6-21]

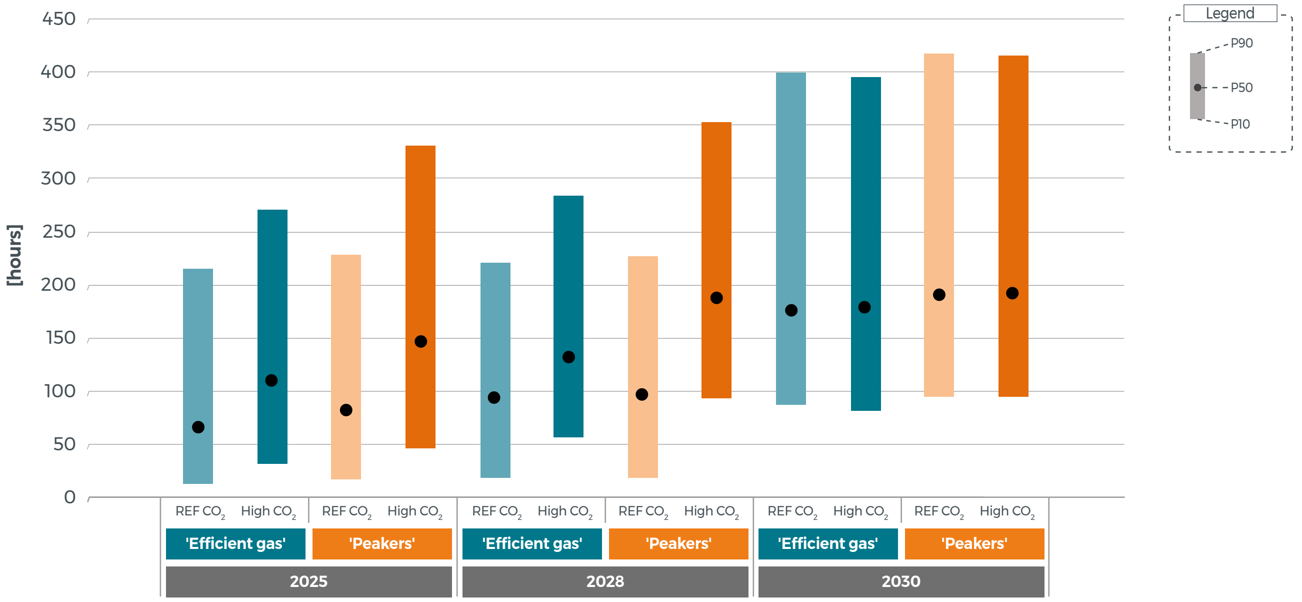


H.2. Unit revenues in different settings

INFRAMARGINAL RENT FOR OCGT INSTALLED IN THE SYSTEM IN BELGIUM FOR 2025, 2028 AND 2030 - EU-BASE IN 'EFFICIENT GAS' AND 'PEAKERS' SENSITIVITIES [FIGURE 6-22]

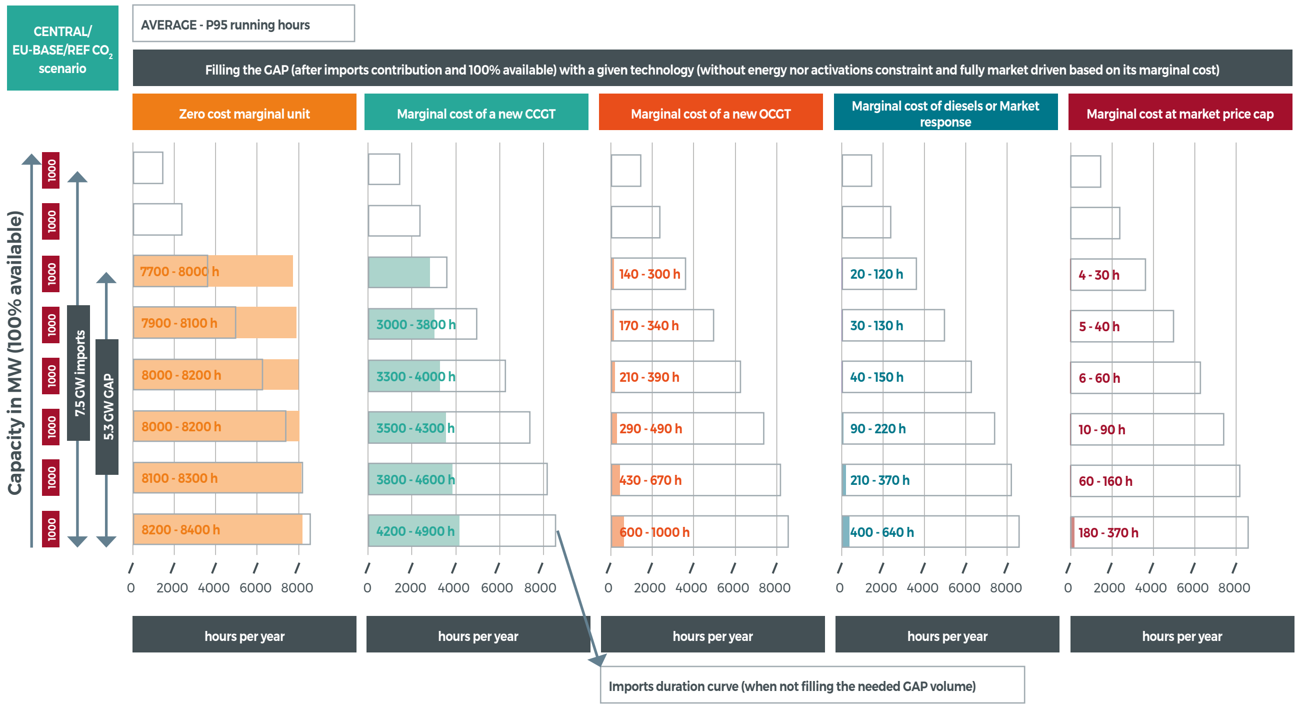


RUNNING HOURS FOR OCGT INSTALLED IN THE SYSTEM IN BELGIUM FOR 2025, 2028 AND 2030 - EU-BASE IN 'EFFICIENT GAS' AND 'PEAKERS' SENSITIVITIES [FIGURE 6-23]

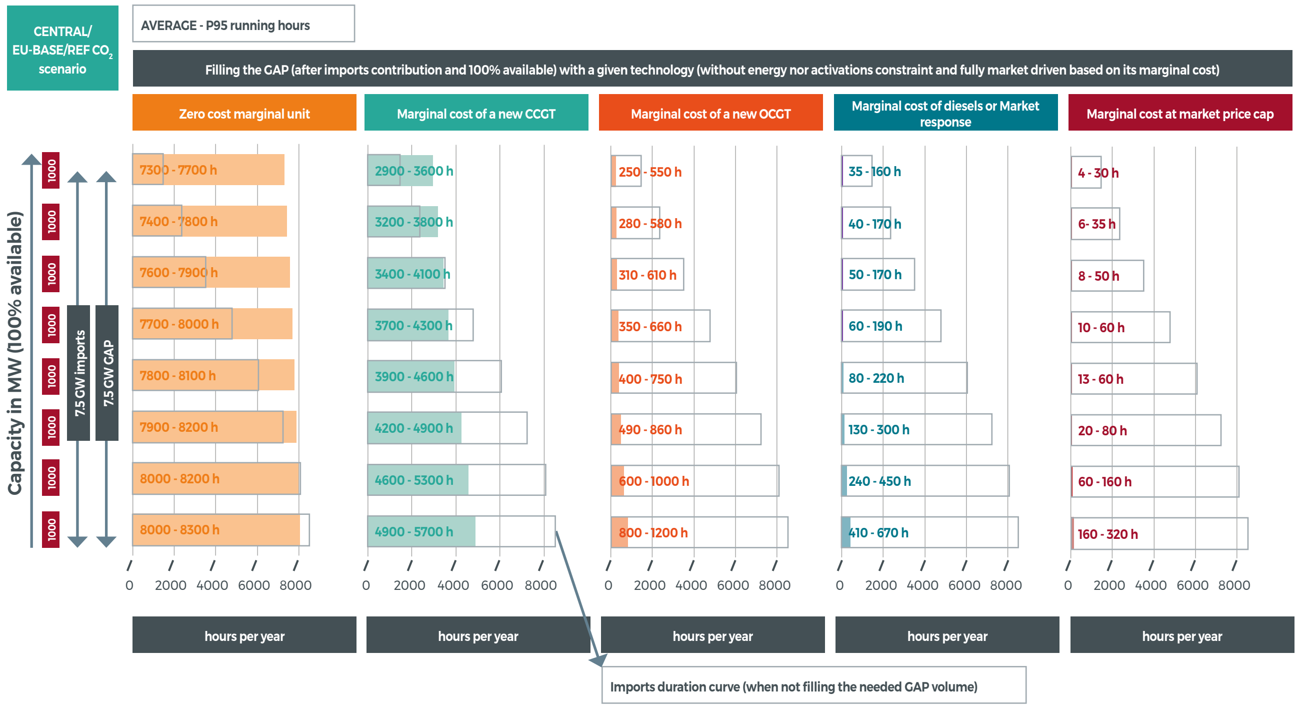


H.3. Running hours for 2028 and 2030

RUNNING HOURS ARE VERY DEPENDENT ON THE TECHNOLOGY CHOICE TO FILL THE IDENTIFIED 'GAP VOLUME' FOR 2028 [FIGURE 6-24]



RUNNING HOURS ARE VERY DEPENDENT ON THE TECHNOLOGY CHOICE TO FILL THE IDENTIFIED 'GAP VOLUME' FOR 2030 [FIGURE 6-25]



H.4. Welfare

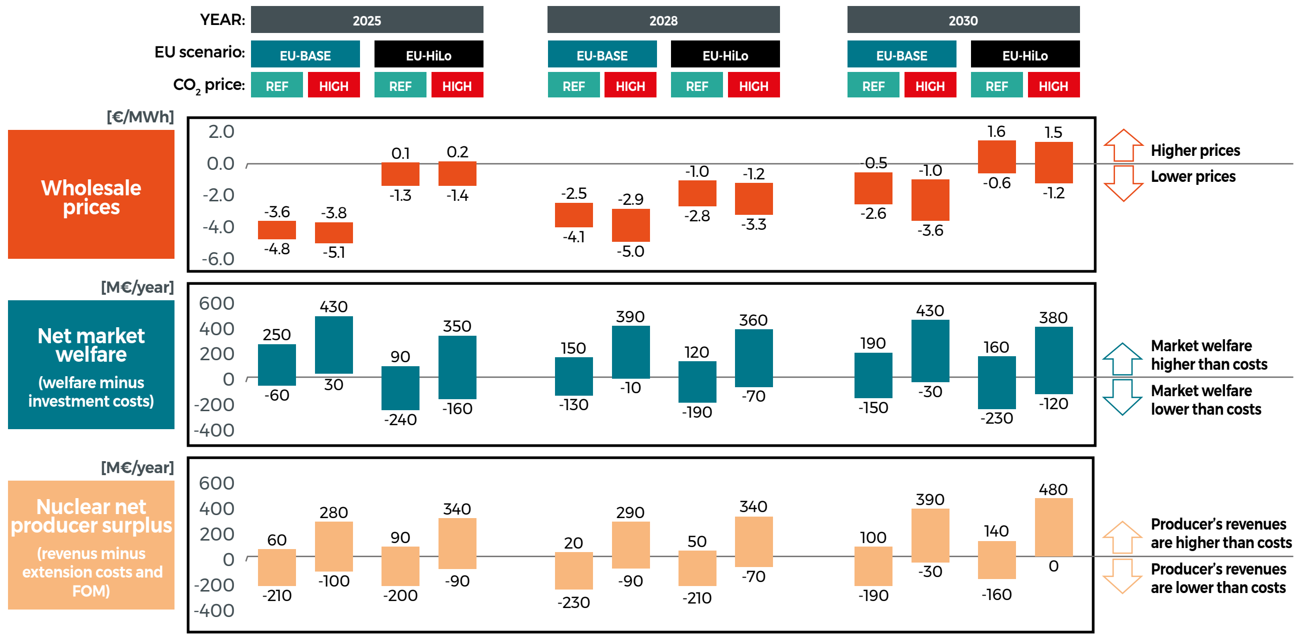
ECONOMIC ASSESSMENT OF DIFFERENT MARKET DESIGN AND CAPACITY MIXES FOR 2025 [FIGURE 6-26]

2025 - 'CENTRAL'/'EU-BASE' scenario		REF / HIGH				
Scenario	Market design	EOM + SR	EM + market wide CRM			
	Which kind of capacity delivers the needed new capacity ?	No intervention, only viable capacity in the rmaket	Efficient gas	Peakers	Decentral	Efficient Gas + CHP
CHP, MR, Storage		'EneryPact' figures for storage (1 GW), PSP (1,4 GW), Market response (2 GW) and constant CHP (2 GW)				
Installed GAP capacity (6.7 GW - 100%)	IN the market / OUT of the market	Existing =2.8 GW SR = 4.1 GW (of which new capacity in SR = 2.4 GW)	All existing = 4.7 GW New CCGT = 2.5 GW	All existing = 4.7 GW New gas engine/OCGT= 2.5 GW	All existing = 4.7 GW New diesel= 2.5 GW (if MR = 7 GW)	All existing = 4.7GW New CHP = 1 GW New CCGT = 1.5 GW
Structural block Costs	Annuity of 'in the market' capacity	-300 M€	-590 M€	-500 M€	-500 M€	-660 M€
	Annuity of 'out of the market' capacity	-190 M€	0 M€	0 M€	0 M€	0 M€
System indicators	Market LOLE	9.4 h	3 h	3 h	3 h	3 h
	Market EENS	23 GWh	3 GWh	3 GWh	3 GWh	3 GWh
	Net imports	31 to 35 TWh	14 to 24 TWh	27 to 33 TWh	28 to 33 TWh	14 to 22 TWh
Market Welfare	BE Market Welfare difference (CS, PS, CR) *Compared to the [EOM-EVC] case*	-	330 to 380 M€	260 to 270 M€	240 to 250 M€	370 to 400 M€
Conclusions						
From the system perspective	Net market welfare difference *(the higher, the better)*	-490 M€	-260 to -210 M€	-240 to -230 M€	-260 to -250 M€	-290 to -260 M€
From a consumer perspective	€ Wholesale price variation *Compared to the [EOM-EVC] case*	-	-5.1 to -4.5 €/MWh	-3.9 to -4.1 €/MWh	-3.9 to -3.7 €/MWh	-5.3 to -5 €/MWh
	⇔ Welfare transfer	+2.2 €/MWh	+3 to +5 €/MWh (estimated cost range for a market-wide CRM)			
	€ Net Price Difference *(the lower, the better)*	+2.2 €/MWh	-2.3 to +1.2 €/MWh			
Delivering security of supply		High volatility. 4 GW strategic reserve needed of which at least half new capacity	Robust security of supply guaranteed by design. 'In the market' capacity brings market welfare and whosale price reduction which at least compensates the cost of the market-wide mechanism.			

H.5. Nuclear extension additional results

NUCLEAR EXTENSION ECONOMICS (IN AN 'EOM+SR' DESIGN) [FIGURE 6-27]

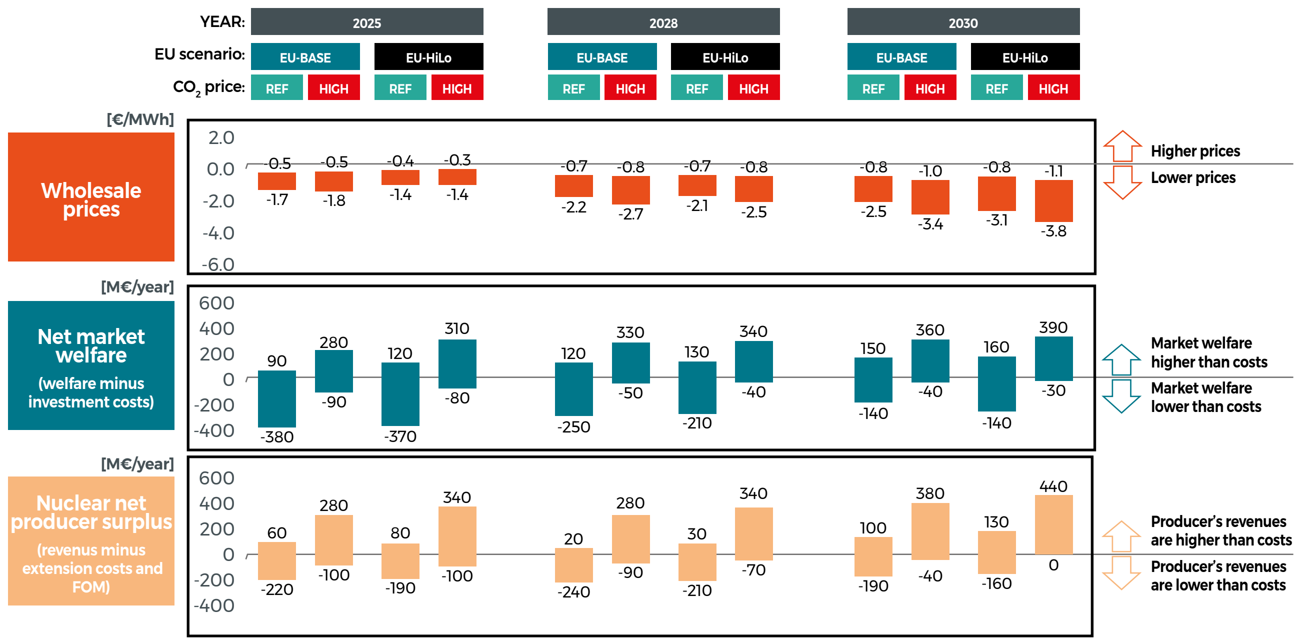
Given range depends on the availability of the units (1 or 2 GW all year long).
The extension sensitivity is compared to the 'EVC+SR'



Note that in an 'EOM+SR' design, there is still a large quantity of 'out-of-market' capacity to be found (of which more than half is new capacity).

NUCLEAR EXTENSION ECONONOMICS (IN AN 'EM+CRM' DESIGN) [FIGURE 6-28]

Given range depends on the availability of the units (1 or 2 GW all year long).
The extension sensitivity is compared to the 'EVC+SR'



7 Most commonly used abbreviations

ACE: Area Control Error
ANTARES: A New Tool for Adequacy Reporting of Electric Systems
ASN: (French) Nuclear Safety Authority
AVG: average
BESET: 'Electricity Scenarios for Belgium towards 2050' study (Elia, Nov. 2017)
CAPEX: Capital Expenditure
CEP: Clean Energy Package
CCGT: Combined Cycle Gas Turbine
CCR: Capacity Calculation Region
CHP: Combined Heat & Power
CIPU: Contract for the Injection of Production Units
CL: 'Classical' power plant
CNEC: Critical Network Element and Contingency
CP: capacity payement
CRE: Commission de Régulation de l'Energie (French regulator)
CREG: Commission for Electricity and Gas Regulation
CRM: Capacity Remuneration Mechanism (usually used for a 'market-wide CRM')
CWE: Central West Europe
EEAG : Environmental and Energy State Aid Guidelines
ENTSO-E: European Network of Transmission System Operators for Electricity
ENTSO-E TP: Transparency Platform of ENTSO-E
(E)ENS: (Expected) Energy Not Served
(E)ENS95: (Expected) Energy Not Served for a statistically abnormal year (95th percentile)
EOM: Energy-Only Market
EPC: Engineering, Procurement and Construction
ETS: European Trading System
EU21: 21 European countries defining the perimeter of the study
EU-HiLo: 'High Impact, Low probability' scenario on European generation capacity
'EU-NoNEW': European scenario assuming no new built gas-fired generation
'EU-noMOTH': European scenario assuming de-mothballing of units
'EU-GRID+': European scenario assuming additional interconnections between CWE and the rest of Europe
EV: Electric Vehicle
EVC: Economic Viability Check
FB: Flow-based
FBMC: Flow-based Market Coupling
FCR: Frequency Containment Reserves
FES: Future Energy Scenarios (National Grid scenarios)
FOM: Fixed Operations & Maintenance costs of a unit
FPS: Federal Public Service
FRR: Frequency Restoration Reserves
- **aFRR**: automatic FRR
- **mFRR**: manual FRR

GSK: Generation Shift Keys
HP: Heat pump
HVDC: High Voltage Direct Current
IHS Markit: Information Handling Services Cambridge Energy Research Associates
LEZ: Low Emissions Zones
LFC: Load Frequency Control
LOLE: Loss Of Load Expectation
LOLE95: Loss Of Load Expectation for a statistically abnormal year (95th percentile)
MAE: Mean Absolute Error
MAF: Mid-term Adequacy Forecast
NTC: Net Transfer Capacity
NECP: National Energy Climate Plan
NEP: Netzentwicklungsplan
NP: Net Position
NREAP: National Renewable Energy Action Plan
OCGT: Open Cycle Gas Turbine
PLEF: Pentalateral Energy Forum
PPE: Planification Pluriannuelle de l'Energie (France)
PSP: Pumped-storage Plant
PST: Phase Shifting Transformer
PTDF: Power Transfer Distribution Factor
PV: Photovoltaic
RAM: Remaining Available Margin
RES: Renewable Energy Sources
RES-E: Share of renewable electricity on the electricity consumption
RoR: Run-of-river
RT: real-time
RTE: Réseau de Transport d'Electricité (French transmission system operator)
SDS: Sustainable Development Scenario (IEA)
SR: Strategic Reserves
TRAPUNTA: Temperature REgression and loAd Projection with UNcertainty Analysis
TSO: Transmission System Operator
TYNDP: Ten Year Network Development Plan
UC: Unit Commitment
V2G: Vehicle-to-Grid
VOM: Variable Operations & Maintenance costs of a unit
WACC: Weighted Average Cost of Capital
WAM: 'With additional measures' scenario from the NECP
WEO: World energy outlook
XB: Cross-border

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