APPENDIX ON METHODOLOGY FOR THE ASSESSMENT ON SHORT-TERM FLEXIBILITY

Version submitted to public consultation for the next Adequacy & Flexibility study 2024-34

28/10/2022

Besides minor textual modifications following recent and upcoming market evolutions, no revisions are proposed to be implemented compared to the methodology presented in the Adequacy and Flexibility Study 2021

1. Introduction

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-1]. Note that newer definitions add characteristics of reliability and cost-effectivity to this definition, as well as stressing the range of timescales from instantaneous stability to long-term security [IEA-2]. As shown in Figure 1, power systems and markets need flexibility to cope with three types of uncertainty (also known as 'flexibility drivers'), as outlined below.

(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 portfolios and manage their operations.

(2) **The variability and uncertainty of renewable and distributed generation:** renewable generation such as wind and solar power is characterised by uncertainty, as it is subject to variable and uncertain weather conditions. This is also the case for some distributed generation sources which face 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 the 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.

Figure 1

In order to keep the system in balance, which is an important prerequisite for system security, these expected and unexpected variations in demand and generation must be covered at all times with flexibility sources, also 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 technologies outlined below.

(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 within an acceptable time frame. An exception is Belgian nuclear power plants, which are typically operated as base load units (although some temporary output reductions have 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 costly, since 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 through modifying its demand following a reaction to explicit signals, or implicitly by reacting to price signals. In this study, these are referred to as consumption shifting and demand response processes respectively. Note that demand side management is generally activated to facilitate demand reductions (a demand increase would imply using more energy than 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. These technologies face limitations concerning their energy reservoir. Several storage technologies exist, but for the moment the most relevant for Belgium are 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 currently underway by means of balancing energy exchange platforms that will facilitate close-to-real-time flexibility exchanges. Note that the availability of this capacity depends on the availability of transmission capacity (besides the 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 demand shedding. On the one hand, flexibility needs have been seen to increase following the increase of renewable generation (e.g. solar photovoltaics) and new demand applications (e.g. electric vehicles). On the other hand, flexibility means are also increasing following the integration of new demand side management (e.g. electric heating) and storage (e.g. batteries) possibilities.

Therefore, the aim of this flexibility study is to investigate if the future power system has sufficient technical capabilities and characteristics to deal with variations in demand and generation.

1.2. Flexibility in the electricity market

The diagram in Figure 2 illustrates the main mechanisms of the operation of the current electricity market.

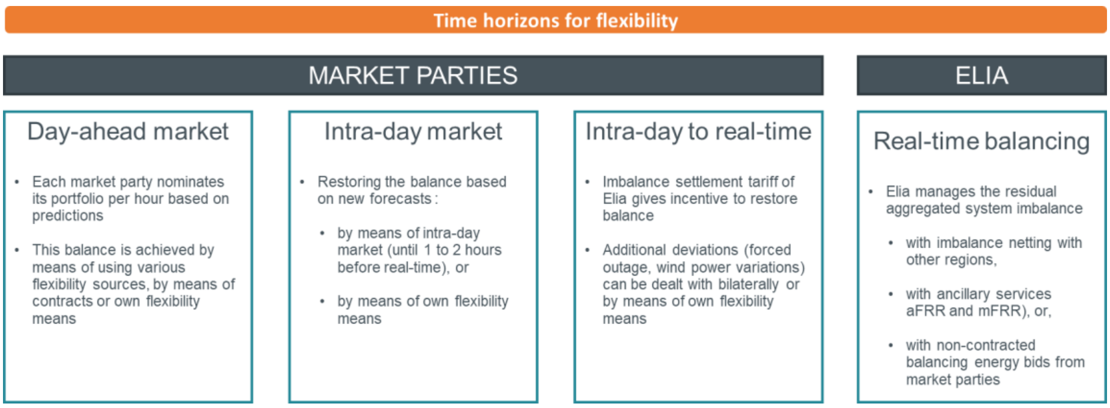


Figure 2

Market players are responsible for balancing injections and offtake in their portfolio. They must currently nominate an energy portfolio one day in advance (day-ahead) that guarantees an equilibrium and, by moving further closer to real-time, resolve any imbalance in their portfolio. It is therefore necessary for the market to have sufficient flexibility, both intra-day and real-time flexibility, to compensate for forecast errors in generation, in particular with regard to renewable energy sources and offtake. In addition, the flexibility available in the system must always allow for the loss of power plants (unavailabilities known a day advance, as well as an unforeseen unavailability after day-ahead). Note that the day-ahead balance obligation of the BRPs (i.e. their obligation to communicate a portfolio in balance in the day-ahead timeframe) is currently being progressively relaxed. This relaxation is a pre-requisite to allow enhanced flexibility management at all times from day-ahead (due to a better back-propagation of the expected real-time value of energy) to the end of the intraday market.

The role of the transmission system operator in managing flexibility is complementary to the market's role, because it neutralises the residual imbalance between injection and offtake that is not covered by market players. By means of the imbalance settlement tariff, Elia incentivises the market to adhere to 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, both in 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.

TSOs use reserve capacity to cover the residual system imbalance as represented in Figure 3. If an imbalance in the system occurs, this results in an increase or decrease in 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.

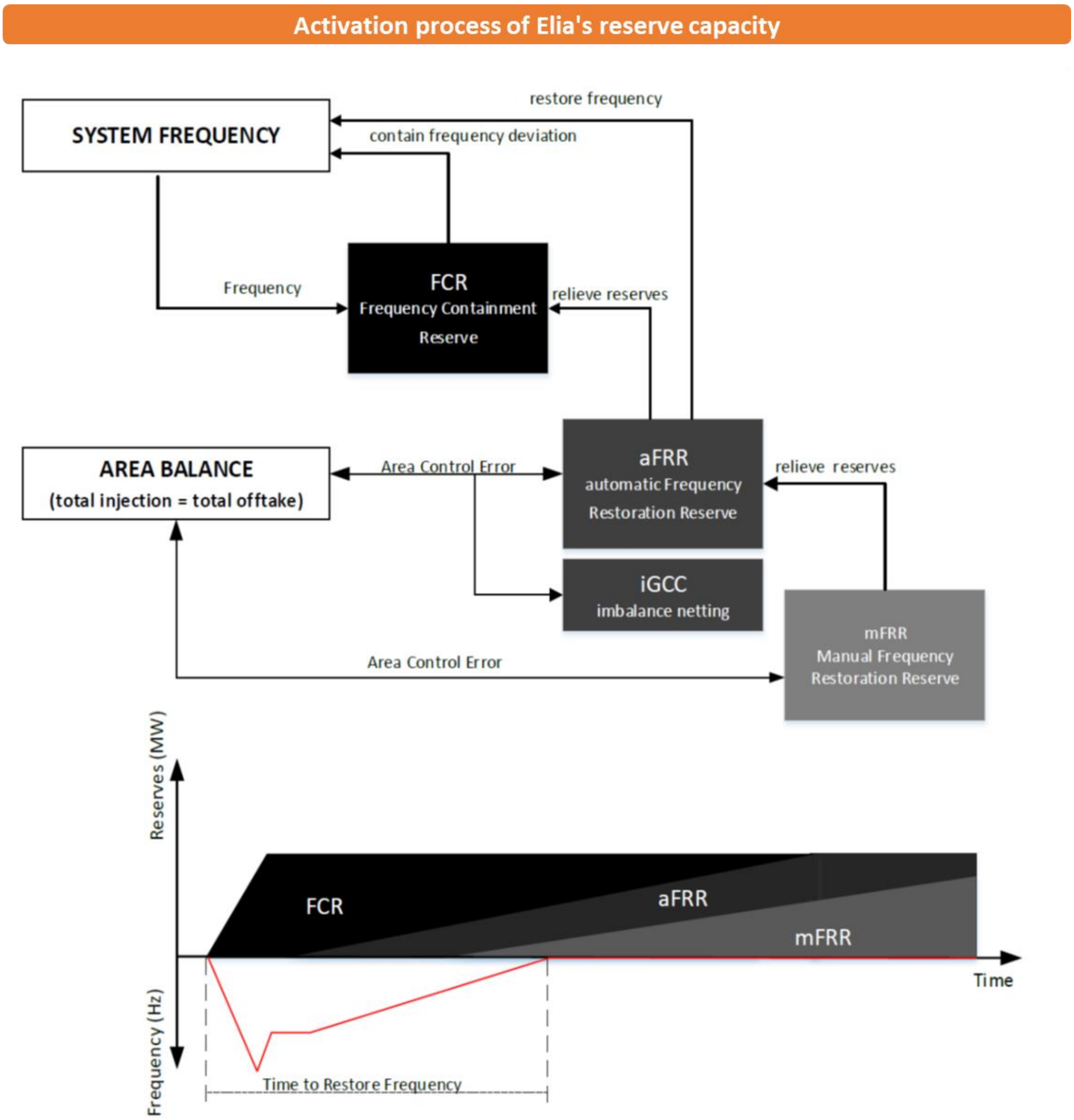


Figure 3

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 1 explains how the required FCR volume is dimensioned by ENTSO-E at European level and allocated to the relevant LFC blocks.

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 on a minute-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. Elia is investigating the possibility of reducing this down to 5 minutes;

- mFRR is manually activated and must be fully available within 15 minutes. This is due to be reduced to 12.5 minutes from 2022 onwards.

The required capacity of FRR is determined by Elia as explained in BOX 1

BOX 1: 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-1]**Error! Reference source not found.**. The FCR capacity for Belgium is 86 MW in 2022.

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-1], subject to a public consultation and approval from the CREG. Since February 2020, this methodology has been based on a dynamic methodology with which Elia determines the up- and downward FRR needs each day based on a calculation of the imbalance risk. This risk is derived from historic observations of system conditions and LFC block imbalances with the help of machine learning algorithms. Results vary from around 1039 MW for upward FRR (rated power of the largest nuclear unit), and up to 1044 MW for downward FRR (rated export power of the Nemo Link interconnector). Note that the up- and downward aFRR needs are currently fixed 'symmetrically' at 117 MW, although the implementation of a new 'dynamic' methodology is currently under discussion. The up- and downward mFRR needs are calculated as the difference between the total FRR needs and the aFRR needs.

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 FRR reserve capacity with other TSOs and non-contracted

1.3. Scope and objective of the flexibility study

As outlined in Figure 4, this flexibility analysis focuses on the flexibility required between the day-ahead and the real-time in order to ensure the balance in the Belgian LFC block. **The flexibility analysis therefore focuses on short-term flexibility, i.e. the capabilities which are required to cover the expected and unexpected day-ahead and real-time variations in the residual load.**

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. Note that long-term outlooks are becoming more important as the share of variable renewable generation continues to grow and renewable generation replaces more of the conventional controllable capacity. Indicators related to a lack of flexibility are typically expressed in terms of expected generation curtailment and lead to discussions on the integration of new technologies such as power-to-gas technologies and sector coupling.

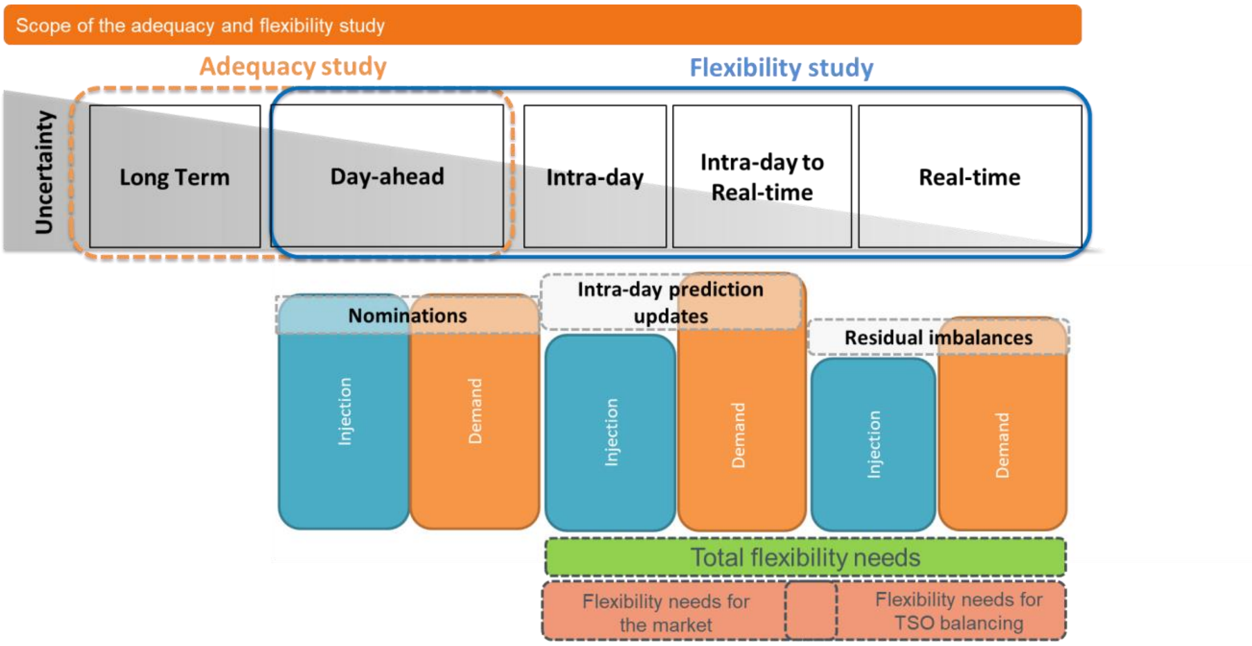


Figure 4: scope of the adequacy and flexibility study

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' decentralised 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.

Before the previous adequacy study undertaken by Elia in 2019, intra-day to real-time variations in the residual load had never been explicitly investigated by Elia. Although the first adequacy and flexibility study in 2016 [ELI-2] highlighted a few characteristics of residual load variations, it mainly focused on estimating the required balancing capacity, and did not investigate in detail whether the system is 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 only focusing 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. The proposed methodology in this study therefore focuses on the total flexibility in the system.

Figure 5 shows the relationship between the flexibility study and the adequacy study. In a **first step**, only on the total flexibility needs required between day-ahead and real-time are calculated. The approach did not determine whether it is the market or the TSO which has to cover the required flexibility.

This split is then investigated in a **second step** by means of making projections on the reserve capacity needs for FCR and FRR to be foreseen by the TSO. The availability of these reserve capacity needs are modelled in the adequacy simulations to ensure minimum flexibility requirements, even during scarcity risk periods. Note that the share of reserve capacity depends largely on the future ability of market players to cover demand and generation variations. Projections are based on assumptions on market performance, and real reserve capacity requirements are only determined by the TSO closer to real-time based on the observed system imbalances.

As the focus of the flexibility needs modelling in adequacy simulations is on scarcity situations, the **third step** studies the total flexibility available in the market by post-processing the results of the adequacy simulations. These available flexibility means are then compared with the required flexibility needs to analyse and prepare for potential challenges.

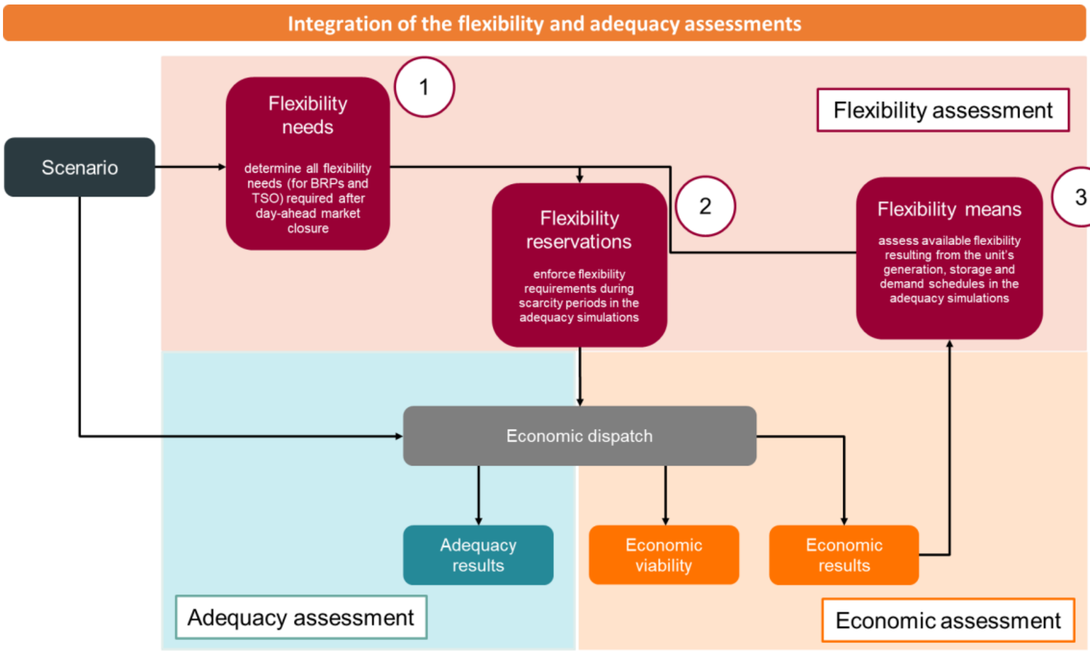


Figure 5

1.4. Best practice

Best practice 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 given the increasing share 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 given the increase in renewable generation. Recent studies in Europe and around the world confirm that flexibility is becoming a crucial area for system adequacy. ENTSO-E provided some first insights into flexibility in one of the previous MAF reports [ENT-2]. At this stage, the literature puts forward three general types of approaches:

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 - instead these are based on historical variations and forecast errors of demand and variable renewable generation. This is based on a time series analysis of historical data which demands a lot of data (i.e. the availability of at least one year of historical observations and predictions). Maximum variations and forecast errors can be used as metrics allowing them to be cross-checked with available system capabilities. Examples can be found with the Finnish TSO [POY-1], as well as recent academic literature [RTE-1].

3. **Modelling flexibility in system models** allows flexibility to be specified in unit commitment and economic dispatch models and is 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 according to which the flexibility needs are modelled (e.g. resolution, time horizon). Examples of such an approach can be found in the academic literature

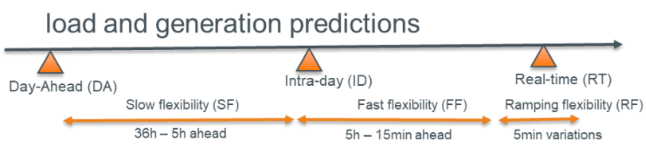
[RTE-1]. Recently, the International Renewable Energy Agency presented a study based on such approaches [IRE-1]

The methodology used by Elia combines elements of the aforementioned approaches: 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 used a new methodology based on current best practice. This approach can be improved and adapted in future, based on feedback from stakeholders and analysis following implementation.

2. Methodology to determine the flexibility needs

The flexibility needs assessment is based on a categorisation of three types of flexibility (Figure 6), derived from the time frame that new information is received by the market players. This may relate to forecast updates, or information concerning the unexpected unavailability of a power plant.

Types of flexibility



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	Deal with intra-day prediction updates of residual load and 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

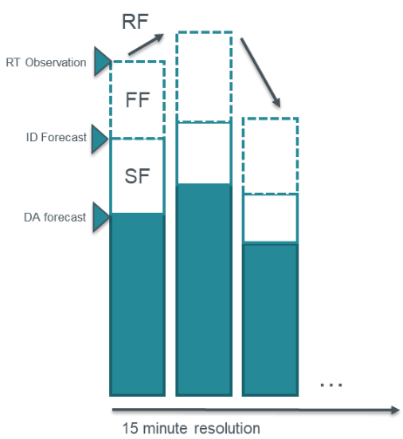


Figure 6

- **Slow flexibility** represents the ability to deal with expected deviations in 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 power plant or transmission asset outages 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 through generation units which are already dispatched and able to modify their output program within a few minutes, or through units which have start or stop time of 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 real-time variations in the forecast error and in particular the forecast errors of the last intra-day forecast before real-time. It can be expressed as the capacity required for up to 5 minutes, or even per minute (MW/min). Note that, due to the availability of higher resolution data for offshore wind power generation, it recently became possible to increase the resolution to 5 minutes. 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-by-minute basis and therefore only those units which are already dispatched, as well as some battery storage and demand side management units 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 6, the most recent intra-day forecast 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 the start-up time of a unit. In general, most units can start up in a time frame of several hours, allowing them to deliver slow flexibility. However, some units can start up within few minutes. These can therefore deliver fast flexibility even when not being dispatched. As shown in Figure 6, 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;

(3) determining the flexibility needs based on a convolution of both probability distribution curves.

This analysis is represented in Figure 7. It is conducted for each future year based on an extrapolation of the relevant time series by means of the demand and generation capacity projections towards that year.

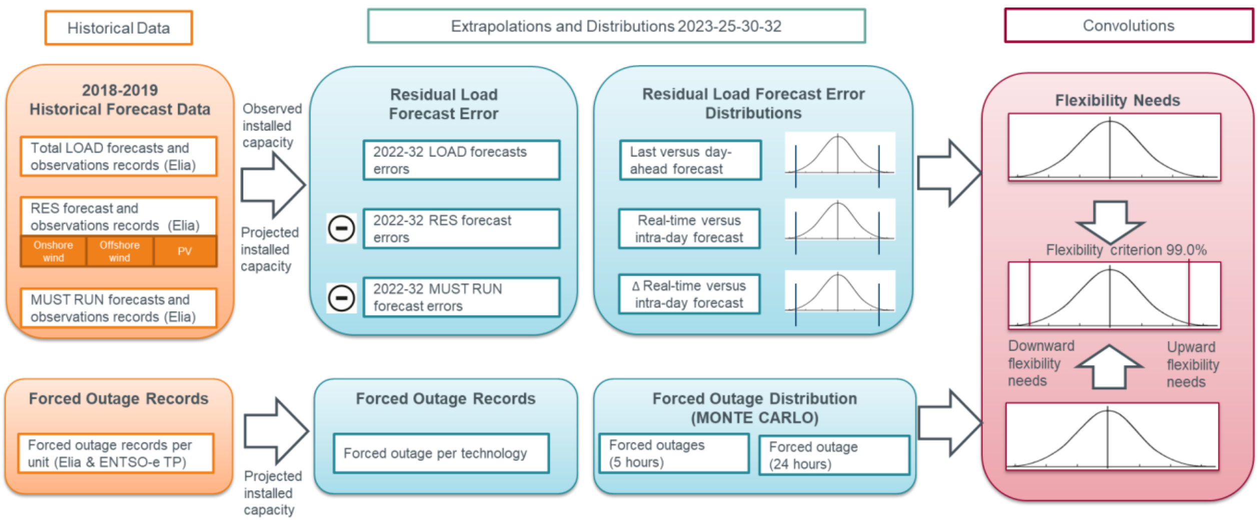


Figure 7

2.1. Step 1: residual load forecast error

The residual load is defined in Section 1.3 and represents variability both due to total load and 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 the energy injected by renewables (wind and solar) or the offtake by the demand is not yet impacted by the activation of flexibility. 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 during the assessment of the available flexibility means.

Figure 8 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 across 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. Export and energy used for energy storage are then 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 Iste Incineration.

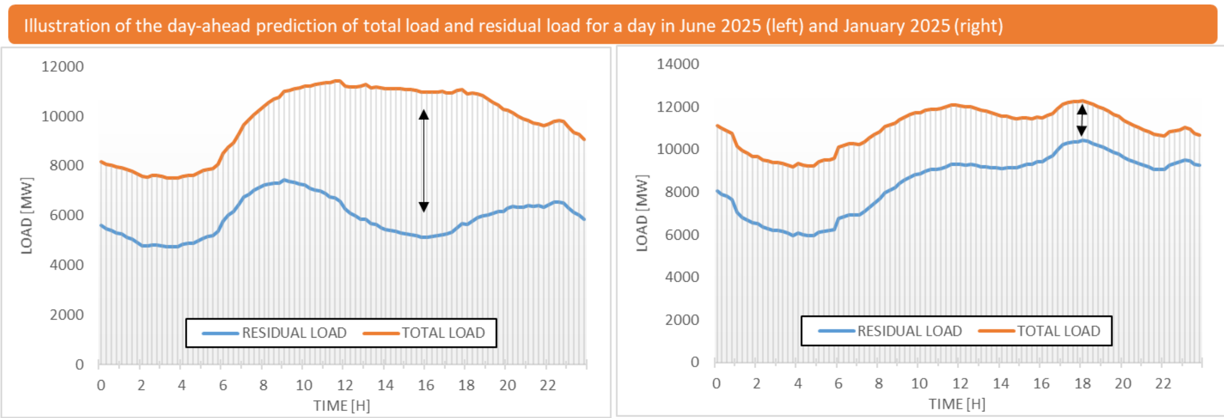


Figure 8

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 the appendix on assumptions for the assessment of short-term flexibility. 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 periods of 5 minutes.

Note that the first two time series originated from 15-minute time series, while the last time series used the available high resolution time series of the offshore wind power combined with 5 minute interpolations for the other time series for the real-time estimations. The forecasts are kept on a 15 minute basis.

Figure 9 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.

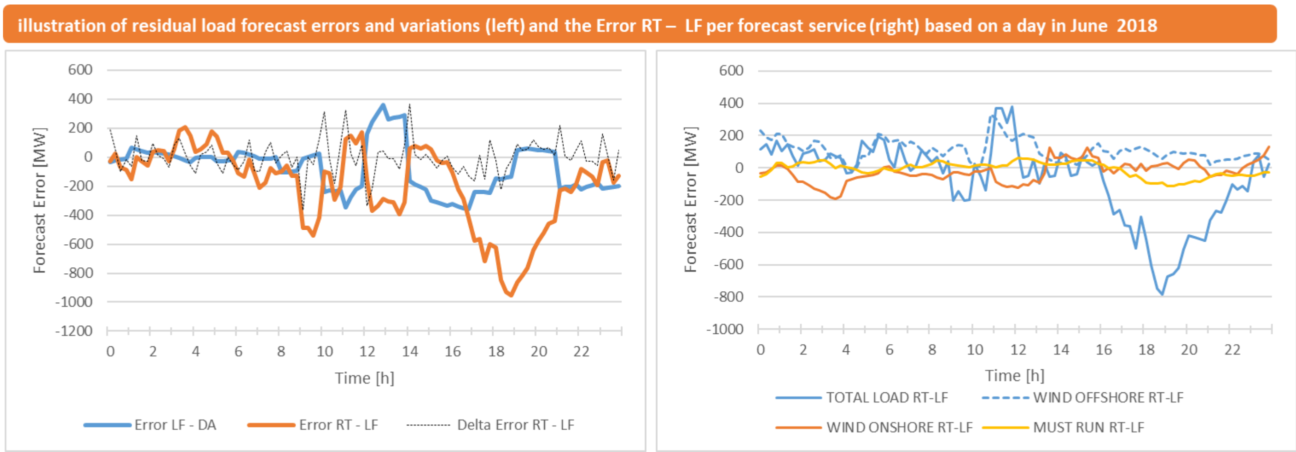


Figure 9

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 enabled Elia to extrapolate the time series towards projected values for the period 2022 to 2032. This extrapolation is conducted by means of the installed capacity and demand projections towards 2032, while taking a forecast improvement factor into account (cf. appendix on assumptions for the assessment of short-term flexibility).

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 for each time horizon investigated and for the Error LF - DA, Error RT – LF and the Delta Error RT – LF, used for the slow, fast and ramping flexibility respectively.

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 in accordance 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, since it is the only electrical connection between Belgium and the United Kingdom.

- **The outage probability and duration**: these parameters are based on a 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 resulted in three probability distributions for each time horizon investigated, taking into account evolutions in the generation fleet (including the nuclear phase-out and the entry of new capacity).

2.3. Step 3: Convolutions and determination of the flexibility needs

In this final step, for each time horizon investigated, the probability distribution curves representing the forced outage risk and the prediction risk are convoluted. This was done for each type of flexibility need:

- **Slow flexibility** : Prob(Error LF – DA) + Prob($FO_{24hours}$)

- **Fast flexibility** : Prob(Error RT – LF) + Prob(FO_{5hours})
- **Ramping flexibility** : Prob($\Delta_{t;t-1}$[Error RT – LF])

This resulted in three new probability distributions per time horizon, for which a reliability level determined the flexibility needs. The 0.1% and 99.9% percentile determined the down- and upward flexibility needs. The flexibility needs for every distribution is determined as the percentile of each distribution. This resulted in up- and downward flexibility needs in MW for the period DA/LF and LF/RT but also in flexibility needs in MW for the delta error LF/RT, which is also expressed as MW/min, by dividing the result by 5 minutes.

A criteria of 99.9% is selected as the trade-off between accuracy and reliability, as there is no legal framework for covering flexibility needs. Choosing the LOLE criteria for both flexibility and adequacy models might have "pushed" the overall reliability criteria below the legal criterion of 3 hours per year. In view of this, a 100% target reliability need to be strived for. However, setting the percentile too high could have made the results too sensitive for extreme events and data problems specific to the historical years considered.

Note that the flexibility needs are considered as fixed. In reality, flexibility needs may vary depending on hour of the day, season and may even be related to other system conditions. A few analyses are carried out on specific subsets (high / low renewable generation, total load and time).

3. Methodology to include the flexibility reservations

While the previous section assesses the total flexibility needs for the system, this section elaborates on which share needs to be covered by Elia through reserve capacity. A TSO's objective is to only cover what is needed to ensure system security in line with the European network guidelines, while incentivising market players to balance their portfolios as much as possible. For this reason, the FRR reserve capacity requirements are determined closer to real-time: since 2019, Elia has implemented a dynamic dimensioning method, according to which its FRR needs are determined on a daily basis for each block of four hours of the next day.

As represented in Figure 10, reserve capacity 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, 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 by means of intra-day markets. Note that the FCR falls outside the three flexibility categories and should be seen as a separate category, dimensioned on the level of the synchronous area of continental Europe and therefore considered outside the scope of this national flexibility study.

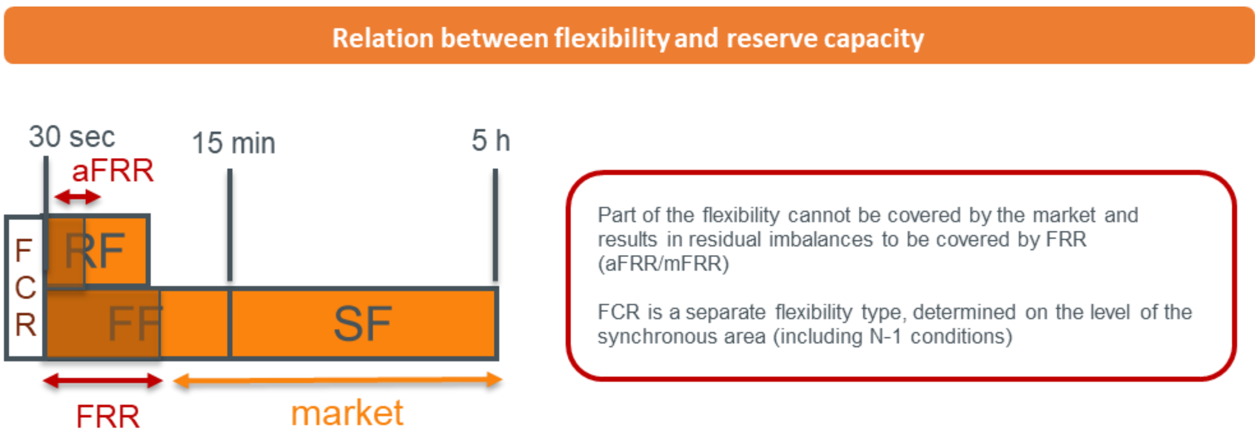


Figure 10

3.1. Modelling reserve capacity requirements in the adequacy simulations

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 production is known in advance on a week-ahead basis, while forecast variations and unexpected 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.

Part of the flexibility needs are explicitly modelled in ANTARES by reserving the FCR and FRR capacity requirements on available generation, storage and demand response assets. This is implemented in line with the ERAA methodology Article 4(6)g [ACE-1]:

"Reserve requirements shall be set separately for FCR, FRR and RR.

i. For each target year, the dimensioning of FCR and FRR, and the contribution of each TSO, shall reflect reserve needs to cover imbalances in line with Articles 153 and 157 of SO GL.

ii. Unless the modelling framework described in paragraph 1(g) is able to model the use of balancing reserves in relation to unforeseen imbalances, FCR and/or FRR (or a part of these balancing reserves) may be deducted from the available capacity resources in the ED […]"

The reserve capacity requirements are therefore included in adequacy simulations by means of additional constraints, which ensure that available capacity in the system covers electricity demand and required reserve capacity needs during periods of scarcity. The adequacy needs of the system are therefore impacted in a way that the system can always cover the day-ahead demand forecast and the balancing requirements (e.g. the loss of the largest power plant). In other words, a capacity meeting the technical requirements of reserve capacity is set aside to cover residual system imbalances that occur after day-ahead. Note that given that this study covers adequacy, only the upward FCR and FRR capacity is taken into account.

By modelling only the upward FCR and FRR, still not all flexibility is facilitated during the adequacy simulations. However, this approach is justified as the flexibility needs during scarcity is assumed to be lower following a lower probability for prediction errors of renewable / decentral generation and demand during low renewable generation. This is also confirmed when analyzing the flexibility needs during particular conditions (cf. result sections).

3.2. Reserve capacity needs projections

In order to integrate FCR and FRR reserve in the adequacy simulations, projections had to be made regarding future reserve capacity needs towards 2034. No specific methodology was developed in the framework of the previous study, but estimations were based on interpolations and extrapolations of existing information. Note that for the calculations, new projections will become available in the framework of the offshore integration study (MOG 2 study), planned to be presented end-2022. It is foreseen that these figures will be used in the calculations of the adequacy and flexibility study.

Note that in the previous study, FCR, aFRR and mFRR projections related to the previous MOG 2 study (2020) have been used to make projections up to 2032, as represented in Figure 11.

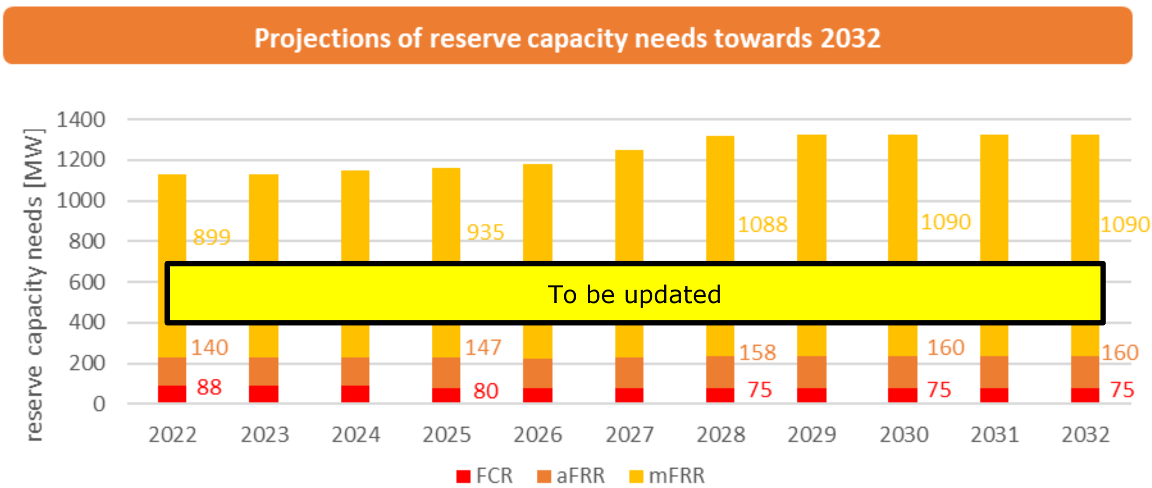


Figure 11

- **FCR needs** are determined by means of interpolating the current value of 87 MW in 2021, calculated by ENTSO-E in 2020 based on its yearly assessment method. As this methodology is based on comparing the total share of load and generation with the total share in the synchronous area of continental Europe, projections towards the future could be made based on estimations of future generation and consumption. For this purpose, results from the MAF for the year 2025 are used. These resulted in a declining volume towards 75 MW in 2025, explained by the phase-out of the nuclear base load in Belgium. Thereafter, the volumes are assumed to remain stable.

- **Total upward FRR needs** are currently dimensioned by Elia through a 'dynamic dimensioning' methodology determining the FRR needs for the next day based on the risks of LFC block imbalances and expected system conditions. One observation is that the FRR needs currently varies around 1039 MW, the rated power of the largest nuclear unit. Simulations carried out in the framework of the integration study on the 2nd wave of offshore wind demonstrated that the average capacity is expected to increase in a reference case towards 1104 MW in 2026 and 1246 MW in 2028, mainly due to new offshore wind power developments [ELI-3]. It is assumed that this increase will stabilises after 2028.
- The split of the upward FRR needs in **aFRR needs and mFRR needs** is currently determined by Elia by means of static methodology, where the aFRR needs are 'statically' determined at 145 MW. In 2019, Elia presented a new 'dynamic' methodology based on a daily calculation which it plans to implement in 2022. Projections are made towards future capacities, where average upward capacity is expected to be between 139 MW and 159 MW in 2026 and 137 MW and 174 MW in 2028 [ELI-4]. The spread is explained by the uncertainty following the ability of BRPs to balance their portfolio within 15 minutes. For reasons of simplification, one of the two values is put forward at 150 MW in 2026 and 158 MW in 2028. The mFRR needs projections are derived by the difference between the total FRR needs and the aFRR needs.

4. Flexibility means

After the flexibility needs we determined, and reserve capacity needs are included in the adequacy simulations, the available flexibility means in the system are assessed. It is to be well understood that for sake of efficiency, and to avoid any overestimations of the adequacy needs, the adequacy assessment only integrated reserve capacity requirements during scarcity periods. In other words, it did not take into account the full flexibility needs of the system for every hour of the year. Therefore, the ex post analysis is needed to derive the available flexibility means during non-scarcitiy periods.

This analysis started from the hourly dispatch of all generation, storage, demand side management units resulting from the adequacy simulations. Taking into account their technical characteristics, the available flexibility from hour to hour is assessed and compared with the required flexibility needs (Section 3).

Figure 12 (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 is calculated for each hour of the climatic years run in the adequacy model. For each hour, the available volume of flexibility from this unit over the period (1 min to 5 hours) is determined.

Assessment of available flexibility of one unit (left) and aggregated over all capacity installed (right)

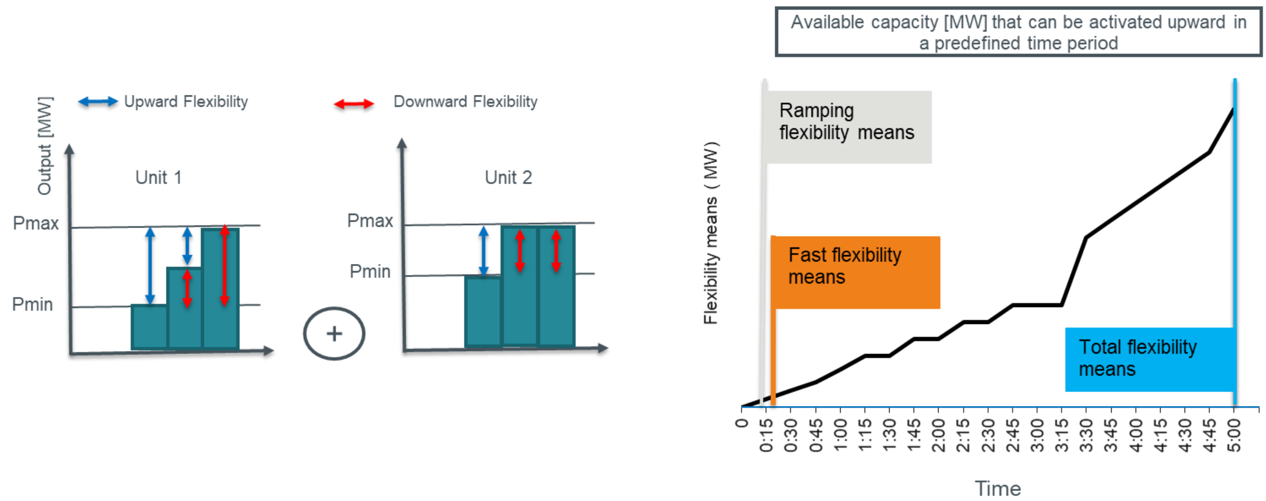


Figure 12

This is based on its technical characteristics, as outlined in the appendix on the assumptions for the assessment of short-term flexibility:

- 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, pumped storage and batteries, electrolysers), 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. Therefore, their flexibility is limited across time;

- for **renewable capacity**, the ability to deliver downward flexibility potential is considered. This took the limited predictability of this type of generation into account;

- for **cross-border flexibility**, the remaining available interconnection capacity (ATC) after day-ahead. This capacity is assumed to be available for slow flexibility through the intra-day market. For fast flexibility and ramping flexibility, this capacity is capped by means of different sensitivities to take into account the uncertainty towards the available energy on the balancing energy exchange platforms with which Elia foresees to connect.

Using these results, the amount of up- and downward flexibility each unit can deliver in 1 minute, 15 minutes, 30 minutes, …, (up to 5 hours) is determined. When these profiles are aggregated, this determined for every hour in every Monte Carlo year the total flexibility which can be delivered between 1 minute and 5 hours, as shown Figure 13 (right). Note that these results are compared the required flexibility needs.

In order to be able to interpret the results over 8760 hours and several Monte Carlo years, the hourly flexibility profiles are further converted into statistics focusing on the available ramping flexibility (5 minutes), fast flexibility (15 minutes) and slow flexibility (5 hours). Note also that the total flexibility expressed the capacity which can be used to cover the fast and the slow flexibility, as shown in Figure 13. The statistics are 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 5 minute are used as a reference to determine the availability level of total, fast and ramping flexibility. A level of 100% represented a guaranteed availability, while 0% represented that the corresponding flexibility volume is never available in the system.

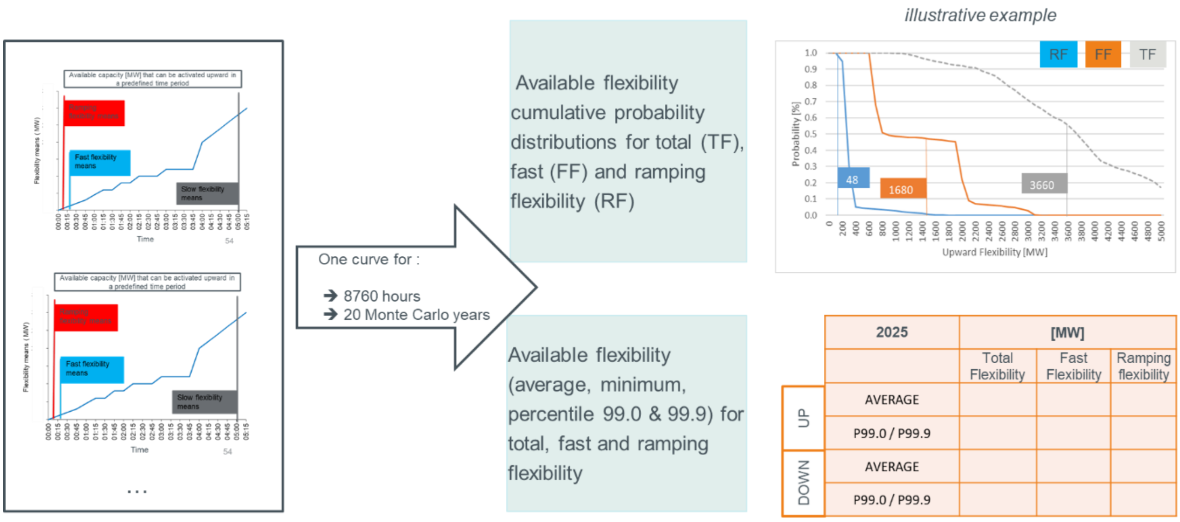


Figure 13

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