ADEQUACY AND FLEXIBILITY STUDY 2022-2032

Public consultation on the methodology

This public consultation lasts from 30/10/2020 until 30/11/2020 6 PM

Stakeholders are free to provide their comments on the content of this document as well as on the other documents of the public consultation (Excel file, Task Force presentation, annexes …) or on the references made to the methodology used in the previous study.

Content

Introduction

1. Context

Elia organizes a public consultation on the input data, sources, scenario and changes in the methodology that will be used for the study regarding the adequacy and flexibility needs of the Belgian power system for the 2022-2032 time horizon.

The consultation aims at receiving any comment from market participants on this data and the proposed changes of the methodology or any other comment on the provided supporting documents. In addition to this document, an Excel file with detailed input data, the presentation of the Task Force and two annexes for the economic viability methodology are included.

The consultation period is set from 30/10/2020 until 30/11/2020, 6PM, was publicly announced on the Elia website and was discussed at a Task Force Adequacy & Flexibility on October 30, 2020.

This public consultation is a voluntary initiative by Elia in order to elaborate a robust study and to collect the valuable input from market parties. Given the significant input and debate on the previous study on Adequacy & Flexibility, the public consultation has been advanced to November instead of January.

In addition, the consultation is extended to also receive feedback on the proposed changes of the methodology. The proposed methodology builds further on the one used in the previous study, and already includes to a maximum extent the provisions of the recently adopted methodology on European Resource Adequacy Assessments. These proposals are still subject to a feasibility assessment, and are hence to be seen as a best-effort intention, without absolute guarantee that all changes can be implemented in the limited timeframe available for the concerned study.

Finally, we recall that for the methodology on flexibility – which was implemented for the first time in the study of 2019 – a call for input was already launched on March 17th, 2020. Should there however be any remaining remarks on the proposed changes, these are equally welcomed via this consultation.

2. Belgian regulatory framework

The legal ground of this study has not evolved since the 2019 study. Article §4bis of the electricity law still reads (in NL and FR):

"§ 4bis. Uiterlijk op 30 juni van iedere tweejaarlijkse periode voert de netbeheerder een analyse uit met betrekking tot de noden van het Belgische elektriciteitssysteem inzake de toereikendheid en de flexibiliteit van het land voor de komende tien jaar.
De basishypotheses en -scenario's alsook de methodologie die gebruikt worden voor deze analyse worden bepaald door de netbeheerder in samenwerking met de Algemene Directie Energie en het Federaal Planbureau en in overleg met de commissie."

§ 4bis. Au plus tard le 30 juin de chaque période biennale, le gestionnaire du réseau réalise une analyse relative aux besoins du système électrique belge en matière d'adéquation et de flexibilité du pays sur un horizon de dix ans. Les hypothèses et scénarios de base, ainsi que la méthodologie utilisés pour cette analyse sont déterminés par le gestionnaire du réseau en collaboration avec la Direction générale de l'Energie et le Bureau fédéral du Plan et en concertation avec la commission.

Prior to this public consultation, there have been 4 collaboration meetings with the FPS Economy and the Planning bureau, in presence of the federal regulator. In addition, a formal bilateral concertation with the federal regulator was held. Throughout these meetings, the elements currently submitted for consultation have been presented and discussed.

Further collaboration and concertation with aforementioned entities is foreseen throughout the further elaboration of this study.

Concerning the legal reliability standard, art. 7bis, §2 (in NL and FR) determines the criterion to be applied for the study:

§ 2. Het niveau van bevoorradingszekerheid dat moet worden bereikt, wordt bepaald door :
1° desgevallend, de geharmoniseerde normen vastgesteld door de in deze aangelegenheid bevoegde Europese instellingen;
2° bij het ontbreken van geharmoniseerde normen op Europees niveau, desgevallend de geharmoniseerde normen vastgesteld op regionaal niveau, inzonderheid op het niveau van de Centraal-West-Europese elektriciteitsmarkt;
3° bij het ontbreken van zulke normen, een berekening van een LOLE van minder dan 3 uur en van een LOLE95 van minder dan 20 uur, aan de hand waarvan de ontbrekende ladingsvolumes, noodzakelijk voor de verzekering van de bevoorradingszekerheid, worden bepaald.

§ 2. Le niveau de sécurité d'approvisionnement à atteindre est déterminé par :
1° le cas échéant, des normes harmonisées établies par les institutions européennes compétentes en la matière;
2° en l'absence de normes harmonisées au niveau européen, les normes harmonisées fixées le cas échéant au niveau régional, en particulier au niveau du marché de l'électricité du Centre Ouest de l'Europe;
3° en l'absence de telles normes, un calcul de LOLE inférieur à 3 heures et de LOLE95 inférieur à 20 heures, par lequel les volumes de puissance manquants nécessaires à assurer la sécurité d'approvisionnement sont déterminés.

In absence of values corresponding to 1° or 2° of article 7 bis, §2, the third bullet applies and are thus used as national reliability criteria.

Eventhough European methodologies have been adopted for the calculation of (elements of) the reliability standard, these are still to be applied and finally proposed. In either case, article 25 of Regulation 2019/943 stipulates that the reliability standard is to be set by the Member State. As long as no change to the above-mentioned criteria in the Electricity law is set, we take this standard as binding for this study.

3. European regulatory framework

The Regulation 2019/943 of June 5th 2019 foresees in its article 23 that a methodology should be elaborated for the European resource adequacy assessment to be followed and carried out by ENTSO-E. This methodology has been adopted by ACER on October 2nd 2020. The link with the national adequacy assessments is made through article 24, which stipulates that such assessments shall be based on the European methodology.

The first application of this adopted European methodology will be in the next European adequacy assessment foreseen by the end of 2021. Furthermore, it is to be noted that the adopted methodology foresees an implementation plan, running up to 2023, for implementing all the methodical changes in the European resource adequacy assessment.

Given that this national study on adequacy and flexibility will be published around six months before the European assessment, and knowing that this first European assessment will not include all the methodical changes described in the methodology, it is obvious that the national study is not required to be fully compliant with the recently adopted European methodology.

However, as leading TSO in adequacy assessments, Elia intends, to a maximum extent possible and feasible, to adapt its methodology already in order to be maximally in line with the future European Resource Adequacy Assessment. The proposed changes are detailed in the following chapters.

Proposed methodology

1. General aspects

The methodology for adequacy studies has been continuously improved over the last decade thanks to the feedback from stakeholders. On one hand, Elia has taken the different improvements added at European/regional levels into account (MAF, PLEF studies) and has also been a frontrunner in several methodological developments which are not yet applied at European level (flow-based methodology, economic viability, ..). This paragraph will focus mainly on the changes of the methodology compared to the last 'Adequacy and Flexibility study' published in June 2019.

The base methodology was described in the previous adequacy and flexibility study published in June 2019[1]. The reader can refer to several pages of the previous study for more information:

- Pages 32 to 33 for the time horizons and perimeter simulated;
- Pages 86 to 99 for the adequacy and economic viability methodology;
- Pages 178 to 195 which detail the flow-based methodology and economic dispatch;
- Pages 100 to 113 which detail the flexibility methodology.

Any comments on those sections are also more than welcome in the context of this public consultation.

In **addition, several improvements are proposed compared to the previous study (with the goal to replace the respective parts of the methodology described in the previous study). Those improvements are detailed in the following paragraphs**. Those were also discussed within the 'Comité de Collaboration' and in concertation with CREG.

1 https://www.elia.be/-/media/project/elia/elia-site/company/publication/studies-and-reports/studies/13082019adequacy-and-flexibility-study_en.pdf

2. Target years to be assessed

The study will cover the years from 2022 to 2032 corresponding to Y+1 to Y+10.
Note that a simulated year runs from September to August in order to keep winters continuous in the simulations. Hence the year 2025 corresponds to the period starting 1st of September 2025 and ending 31st of August 2026.
We propose to simulate the following time horizons: 2022, 2023, 2025, 2028, 2032 which correspond to key events happening in Belgium or abroad (also illustrated on figure 1 below).

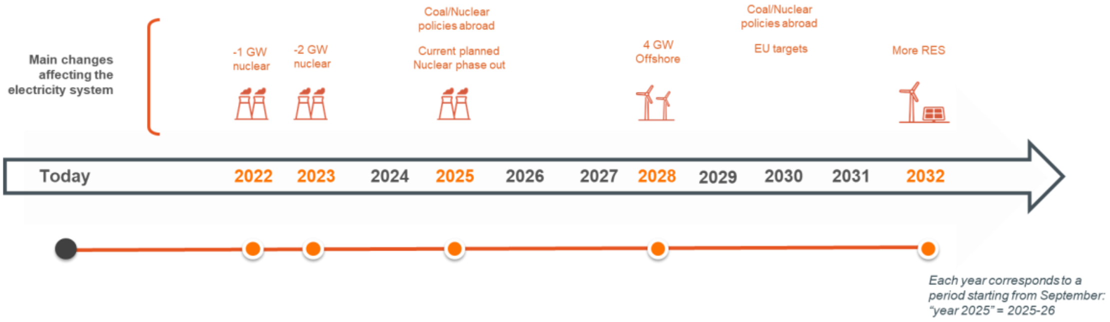

Figure 1: Proposed time horizons to be assessed

3. Perimeter of the market simulation

We aim to add additional countries to the assessment to cover at least the whole CORE region (as we will build CORE flow-based domains) and all EU countries. The following countries will be therefore added to the assessment: Lithuania, Latvia, Estonia, Romania, Bulgaria, Greece and Croatia.

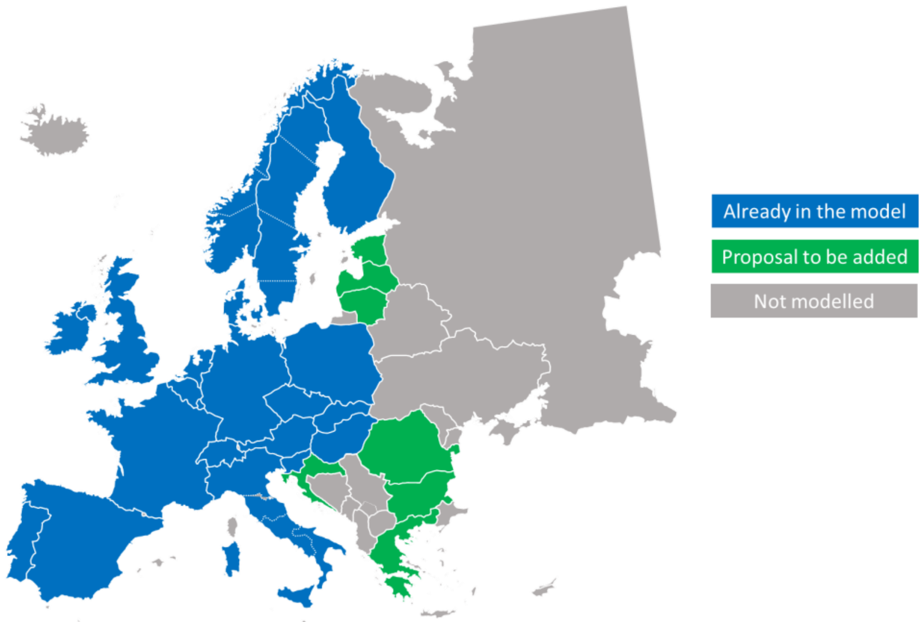

Figure 2: Perimeter to be simulated in the study

4. Climate years

Context

In the previous studies, in order to be in line with the European adequacy studies, Elia has used the PECD (Pan European Climate Database) from ENTSO-E consisting of a set of 34 historic climate years (from 1982 to 2015[2]). The same database is also used by the different MAF and PLEF reports such as the MAF2019[3] and the PLEF GAA 2020 report.

The recently adopted ERAA methodology indicates that the future PECD should reflect evolutions of the climate conditions as depicted below (copy of the Article 4 (f)). Elia will aim to follow this evolution in order to better grasp this future requirement of the ERAA methodology, although the final implementation choice by ENTSO-E (as 3 options are left) will be only known in the coming years.

> (f) The expected frequency and magnitude of future climate conditions shall be taken into account in the PECD, also reflecting the foreseen evolution of the climate conditions under climate change. To this effect, the central reference scenarios shall either
>
> i. rely on a best forecast of future climate projection;
>
> ii. weight climate years to reflect their likelihood of occurrence (taking future climate projection into account); or
>
> iii. rely at most on the 30 most recent historical climatic years included in the PECD.
>
> Other scenarios and sensitivities may rely on climate data beyond the one used for the central reference scenarios, e.g. pursuant to Article 3.6(e).

Figure 3

[2] Note that an additional historical year was added recently by ENTSO-E bringing it to 35 years

[3] **https://www.entsoe.eu/outlooks/midterm/**

Proposed way forward

Elia aims to comply with option 1 as it seems the most preferred and statistically sound alternative. To this end, Elia is currently investigating the implementation of the ‘200 synthetic climate years’ approach that the French TSO (RTE) has used since several years in its national adequacy assessment. Those climate data are provided by meteorological models run by MeteoFrance and are calibrated in order to represent different climate conditions. The data covers the whole Europe and needs to be transformed in order to be used by economic dispatch models. More explanation is given in the next paragraph. Additional links are provided below for the interested reader on public documentation from RTE/MeteoFrance. In order to be used for the next Adequacy and Flexibility study, several steps are required before simulations can be performed and there is no guarantee that this can be implemented in time before the publication of the study. In case the intended implementation shows not to be feasible, alternative approaches will be investigated and proposed.

4.1. 200 synthetic climate years representative of the climate conditions

These envisioned climate years are no longer historical climate years, but they are built to take a certain evolution of the climate into account. For a given target time horizon, several parameters are determined (concentration of green-house gases, stratospheric ozone and aerosols, etc.), followed by the generation of variables such as the temperatures or the wind speeds by the model.
For a specific target time horizon, not only a single climatic projection is generated but a large number of meteorological situations are created. This process is schematically depicted in the lower part of the figure hereunder. Because the climate years are simulated for one specific time horizon, they are called “climate years at constant climate”.
In particular, for one given target time horizon, which is a given “constant climate”, the model from MeteoFrance simulates 200 different climate years. These 200 climate years are equally likely to happen (“équiprobable”) under the climate of that given horizon.

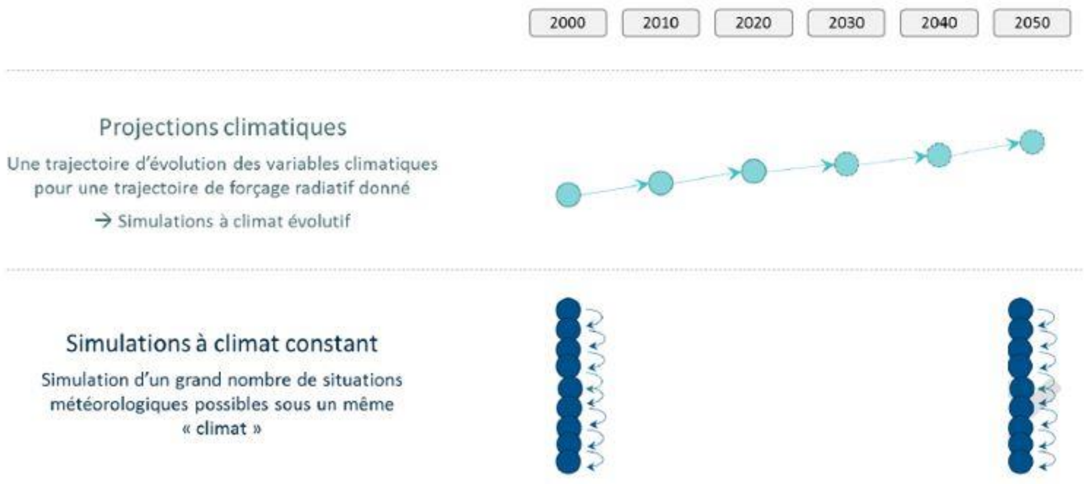

Figure 4: Source RTE – Illustration of the projections and constant climate principle

4.2. Three time horizons available

In order to take the climate change into account, Météo-France generated a set of 200 climate years under the climate of 2050. Actually, they generated two different sets of climate years for 2050, depending on two IPCC (GIEC) scenarios. One is based on the Representative Concentration Pathway (RCP) 4.5 and the other on RCP 8.5, which are two different evolutions of the greenhouse gases emissions (see picture). These trajectory parameters are used as input variable of the model.

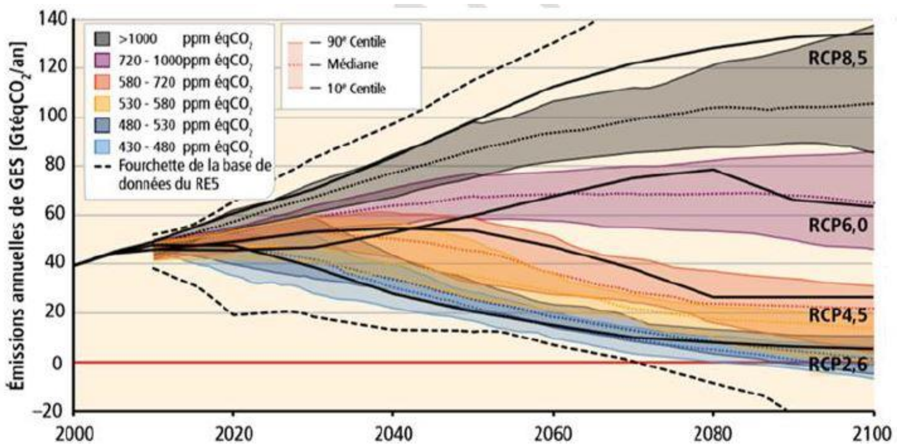

Figure 5: Source IPCC - Evolution profiles of greenhouse gases in the different RCP scenarios

A set of 200 climate years for the constant climate of the year 2000 has also been created by Météo-France. Finally, in order to have an intermediary time horizon, they deducted also a set for the constant climate of 2025, based on the results from 2000 and 2050 scenario 8.5, given that the greenhouse gases emissions today tend to an evolution most in line with the 8.5 scenario.

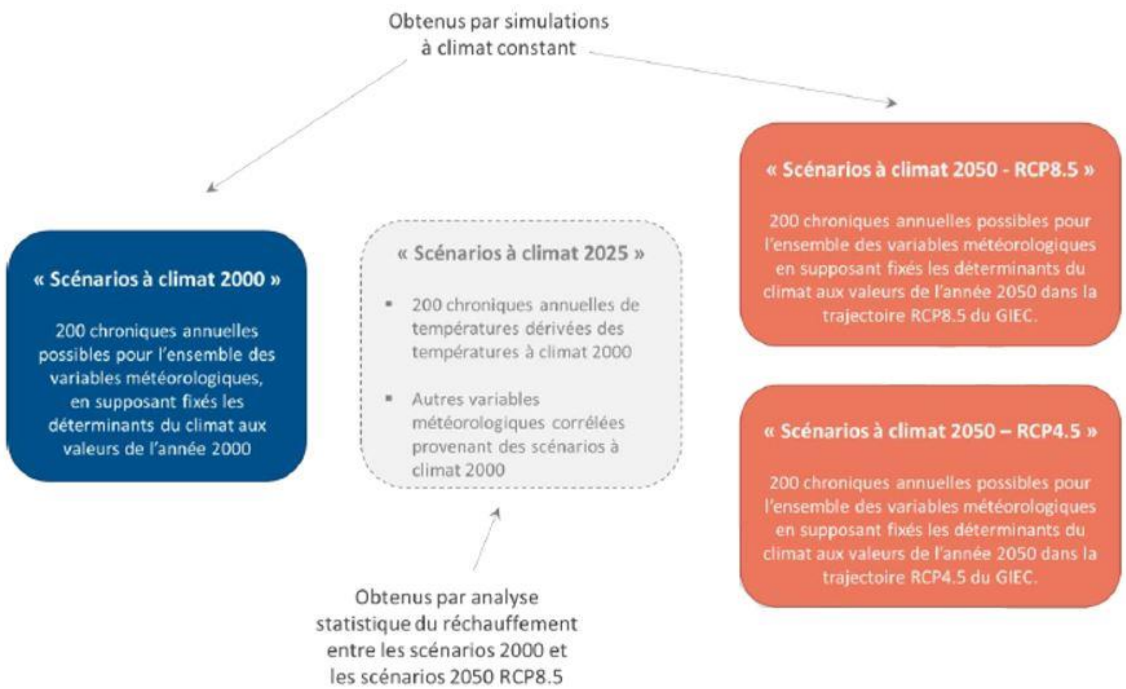

Figure 6: Source RTE - Description of the three time horizons generated

For the next Adequacy and Flexibility study, which covers the time period 2022-2032, and in order to be representative for this horizon, we propose to focus on the scenario with constant climate of 2025.

4.3. From weather variables to generation variables

The climatic database contains data such as temperatures, precipitation, wind, solar radiation, etc. for thousands of points in Europe. In order to construct time series of electrical generation (PV generation, wind onshore/offshore generation and hydro generation) and electricity consumption to be used in the models, an aggregation (from thousands of points in Europe to country level) and a translation (e.g. from wind speed to wind turbine generation) of the weather variables has to be performed. Such process is very complex and computationally intensive. Elia is currently investigating what is possible to re-use from the work performed by RTE for their studies. In addition, the possibility to re-use the tools used by ENTSO-E will be investigated if the required data or tools would not be available from RTE.

4.4. Additional information for the interested reader

More information regarding this RTE/MeteoFrance database can be found in the following document created by RTE: « *Groupe de travail "Référentiel climatique" – Représentation des effets du climat sur le système électrique – Document de cadrage n°1 : les données climatiques utilisées pour la construction des scénarios de mix électrique à horizon 2050* »
https://www.concerte.fr/system/files/document_travail/GT%20Base%20climatique%20-%20cadrage%20donnees%20climatiques%20-%20vdiff2.pdf

Alternatively, a more high level document from MeteoFrance is available as well:
http://www.meteofrance.fr/documents/10192/22603710/DP_servicesclim.pdf

5. Economic Viability Assessment

The Economic Viability Assessment (EVA) is a key aspect of the study. Indeed, the viability of existing and new capacities needs to be assessed and helps in defining whether an intervention is appropriate. Such economic viability assessment was already introduced in the previous study (for more details the reader can refer to pages 95 to 98 of the previous Adequacy & Flexibility study). The viability assessment was only performed for Belgian capacities, following a metric consisting of the median on the simulated revenues for 1 year, which were assessed against the annuity of investments/fixed costs (taking into account the minimum values in the CAPEX/FOM table and with a given WACC). Some capacities were excluded from the EVA given that their viability depends on other drivers such as subsidies or policy targets (CHPs, DSM, storage…). For those, only an ex-post (qualitative) assessment was performed while keeping the pre-defined increased capacities from the different scenarios. The EVA module was set up to be an iterative process consisting of economic dispatch simulations and retirement/investment decisions between each of the simulation steps. The iterative process was stopped once an equilibrium was found (being the situation where all capacities monitored in the EVA were viable according to the chosen metric, and no additional capacity would be viable).

Since the publication of the previous adequacy and flexibility study and awaiting the ERAA methodology, Elia took the initiative to initiate a study by a Professor in Finance with relevant expertise in this field (prof. K. Boudt) to assess how actual investment behaviour could be realistically integrated in the analysis to further refine the EVA methodology. The outcome of this study is further detailed in the next paragraph, while the full study is included in annex of this public consultation.

In addition, other improvements are also proposed in order to extend the EVA or to justify some choices based on the ERAA methodology.

5.1. EVA in the ERAA methodology

The EVA is detailed in article 6 of the ERAA methodology, that article consists of several paragraphs which can be summarized as follows:

- Paragraphs 1 to 3 and 7 to 8 deal with general aspects on the EVA methodology, with paragraph 2 indicating that the EVA shall either assess the viability for each capacity (iteratively) or by minimizing the overall system costs (where all capacities are optimized at once).
- Paragraphs 4 to 5 outline the basic principles of the EVA methodology in case the iterative approach (in line with paragraph 2 (a)) is applied, i.e. for a target year the capacity provider is viable if its revenues are higher than or equal to its costs:
    - Paragraph 9 details the revenues that should be taken into account, i.e. the expected revenues from the wholesale electricity market (taking into account probability-weighted average of the simulated prices) and other expected revenues (e.g. from other electricity-related services). For target years for which hedging products are expected to be unavailable or unable to fulfil the hedging needs of the capacity resources, a market-conform and transparent increase in the WACC for these target years may be used to account for the price risk (WACC increase should be in accordance with the VOLL/CONE/RS methodology).
    - Paragraph 10 describes the costs to be taken into account, which are equal to the sum of all costs expected to be incurred by the capacity resources.
- Paragraph 6 describes the approach based on minimizing overall system costs, in accordance with paragraph 2 (b).
- Paragraphs 11 to 16 provide more detailed principles for the EVA methodology, including the demand, the grid constraints, market and regulatory constraints, as well as the effect of risk management strategies towards price volatility.
- Finally, paragraph 17 to 19 impose some procedural aspects to be followed by ENTSO-E.

5.2. Basic principle

Article 6, paragraph 2 of the ERAA methodology indicates that the EVA shall either assess the viability for each capacity (iteratively) or by minimizing the overall system costs (where all capacities are optimized at once). The ERAA methodology defines the approach 'minimising total costs' as a "simplification" in paragraph 6.

We propose to use the first approach defined in paragraph 2 (a) which will consist of a similar set-up used in the previous study being an iterative assessment of the economic viability. For each iteration, the viability of all monitored capacities will be evaluated following a metric explained in the next paragraph of this document. After each iteration, new capacity would be added (if viable) or existing 'in the market capacity' would be removed from the system (if not viable). The loop of iterations will stop once all monitored capacity in the system is viable and no new capacity is viable.

5.3. Metric for economic viability assessment

Context

The aim of the proposed EVA methodology is to apply a metric that replicates as closely as possible the actual decision making of investors/market players in the Belgian energy market. The main drivers of such an investment decision are:

- Costs: Fixed costs in terms of capital expenditures and operations and maintenance costs, which are predictable;
- Revenues: The inframarginal rents (i.e. the market revenues remaining after subtracting the variable costs such as fuel and variable operations and maintenance costs) depending on many parameters, whereby some of them are impossible to be known in advance, introducing important uncertainties in the investment decision. In addition, the occurrence of extreme price spikes with a low probability result in a high variability of the simulated inframarginal rents and thus in a highly non-normal distribution;
- Required rate of return: This required rate of return for the investor is highly dependent on the perceived risk of the project, as well as the investor's behavior towards risk. In this way, the investor's risk aversion plays a key role in assessing the economic viability, especially in view of the large variability of the simulated revenues.

Elia has requested external input to develop an updated methodology for the economic viability check and to account for investor's risk aversion in modelling economic decisions in a manner in line with the relevant ERAA stipulations. A first note (annexed to this public consultation) from economic expert consultants FTI-Compass Lexecon, "*Risk modelling in adequacy assessments*" highlights the importance of risks and uncertainties for investor's economic decisions and maps out the different risk and uncertainties associated to investments in the energy sector. The note concludes that these risk and uncertainties are to be accounted for in adequacy assessments, but points to the limitations of the currently existing approaches.

Building further on this note, the preliminary study report "*Economic viability of investments in electricity capacity: Design of a simulation-based decision rule*" performed by Professor K. Boudt (annexed to this public consultation), provides a theoretical and academic framework for investor's behavior and the impact of risk aversion, translated into a pragmatic approach to apply this in practice.

More specifically, the study of Professor Boudt assesses the need to cover for risk aversion in investment decisions, substantiated via two theoretical frameworks that are well known in the academic literature, i.e. utility theory and prospect theory. It follows from these frameworks that a risk-averse investor always prefers receiving a given expected return with 100% certainty over receiving an expected return p with x% probability and an expected return q with (1-x%) probability, even if the overall expected return is the same. These conclusions are particularly relevant in the Belgian electricity sector given the expected revenue distributions, amongst others characterized by (extreme) price spikes that might occur, but only with a low probability. The remainder of this section describes the proposed metric more in detail.

<u>Decision rule</u>

Notwithstanding the high complexity and uncertainties surrounding such a multifaceted investment decision, impacted by investor's risk aversion and the particular characteristics of the revenue distribution in the Belgian electricity market, the proposed methodology aims to apply an investment decision rule that allows for a feasible integration in the modelling set-up, while accounting for real-world investor risk/return preferences and incorporating the European methodologies.

According to the proposed methodology, a capacity is considered as viable in the Belgian electricity market if the simulated internal rate of return of a project exceeds the so-called hurdle rate, equal to the sum of an industry-wide reference WACC and a hurdle premium. The hurdle premium aims to cover for aspects going beyond the typical factors and risks covered by a standard WACC calculation as well as to cover for the project-related aspects.

<u>Internal rate of return</u>

The proposed methodology starts by simulating the distribution of the internal rate of return of the project. The internal rate of return for a sequence of "*K"* cash flows is the rate R for which the net present value ("*NPV*") equals 0:

$$NPV = -I + \sum_{t=}^{K} \frac{IR(t)}{(1+R)^t} = 0$$

The calculation above uses the fixed costs ("*I*") and the inframarginal rents ("*IR*") as input parameters.

<u>Hurdle rate</u>

Such hurdle rate consists of the following 2 components:

- <u>Reference WACC</u>: A reference industry-wide WACC (real and pre-tax) for all possible investment in capacity in the Belgian energy market is calculated based on the following formula, in line with the non-binding principles set in the European methodology for the VOLL, CONE and Reliability Standard:

$$WACC = \frac{1 + \left[CoE * \frac{1-g}{1-t} + CoD * g\right]}{1+i} - 1$$

  The input parameters for this real and pre-tax WACC calculation are the cost of equity (CoE), the gearing level (g), the tax rate (t), cost of debt (CoD) and the inflation rate (i). This formula starts from the standard CAPM cost of capital model and the proposed value for the real and pre-tax WACC is 7% as included in the Excel file of the public consultation (on sheet '3.2 Investment costs').

- Hurdle premium: A hurdle premium is added to the reference WACC to cover for an investor's risk aversion towards several specific risks, not captured in the standard reference WACC calculation, as argued in both the FTI-Compass Lexecon note and the report of Professor Boudt as well as to cover for the project-related aspects. The hurdle premium is determined for the different technology classes included in the economic viability assessment:
  - Reference WACC differentiation: As the reference WACC is set at an industry-wide level a project-specific premium should adjust for the WACC where the premium is a mechanical consequence of difference between the project-specific gearing ratio or cost of debt.
  - Extreme price spikes and non-normal revenue distribution: The occurrence of (extreme) price spikes (with low probability) in the simulated electricity prices result in a non-normal distribution of the inframarginal rents. As the CAPM cost of capital, applied to calculate the reference WACC (see above), takes a normal distribution of the return series of the project as a hypothesis, the hurdle premium should account for the impact of the non-normality of the inframarginal rents (which increases with the level of the price spikes). The calculated skewness and kurtosis values typify the level of non-normality.
  - Risk/return relationship (including downside risk): Where the expected project return is driven by the occurrence of a limited number of (very) high price spikes, the investor faces important downside risk, i.e. the risk that these price spikes do not materialize, resulting in a lower than expected project return. The higher this downside risk, the higher the required hurdle premium. The "value-at-risk" and "expected shortfall" metrics are indicators for this downside risk.
  - Model risk includes the uncertainty on whether the simulation is based on a realistic and stable scenario in view of the investment horizon as well as the ability of the simulation setup to fully mimic actual market functioning. Elimination of model risk is impossible due to a.o. the non-linear dependence between the decisions of various market players, the long horizon of the investment and the international context of the electricity market.
  - Policy risk impacting capacity mix and market design: The risk on regulatory and political interventions that impact the profitability of a given technology (e.g. impact of the Green Deal and the uncertainty on the way the energy transition will be implemented). In addition, the risk of regulatory and political intervention in case of a sustained period of extreme high prices increases the policy risk.

Based on a quantitative and qualitative assessment, the level of risk (low/high/medium) is set for all these aspects for every technology in the analysis. The higher the total perceived risk, the higher the hurdle premium that is applied for that technology:

	Non-normal distribution	Risk/return relationship	Model Risk	Policy Risk	Reference WACC differentiation
Type of assessment	Quantitative/Qualitative	Quantitative/Qualitative	Qualitative	Qualitative	Qualitative
Technology 1	Low/Medium/High	Low/Medium/High	Low/Medium/High	Low/Medium/High	Low/Medium/High
Technology 2	Low/Medium/High	Low/Medium/High	Low/Medium/High	Low/Medium/High	Low/Medium/High
Technology …	Low/Medium/High	Low/Medium/High	Low/Medium/High	Low/Medium/High	Low/Medium/High

As part of the public consultation process, Elia would like to receive feedback from market parties on the risk appreciation allowing to calibrate appropriate levels of the hurdle premium that would be applicable in function of the level of risk in the different categories. Note that obviously the different risks can be appreciated differently per technology.

5.4. Considering forward prices for horizons up to Y+3

As mentioned in paragraph 9 (a) (i) of the ERAA methodology, forward prices may be assumed when available. In Belgium, forward prices are only known up to Y+3 and to our knowledge only certain types of contracts or prices are made public. In addition, paragraph 9 (a) (ii) mentions that expected ED prices may be used to determine expected revenues from electricity markets

Our proposal is to use the metric defined in the previous section and perform a check with existing forward public contracts when available and relevant. Depending on the technology and the forward term (e.g. Y+1 ⇔ Y+3) it may indeed be useful to add nuance in terms of actual hedging opportunity (e.g. related to market depth, available products (base, peak,…)).

5.5. Considering additional revenues and types of capacities to be monitored

Article 6, paragraph 9 (b to e) of the ERAA methodology mentions that additional revenues need to be taken into account in the EVA. Those concern revenues from ancillary services, revenues from other services such as heat, revenues from subsidy mechanisms or revenues from CMs. In addition, Article 6, paragraph 3 mentions that capacity resources based on exogenous assumptions according to the national baseline data may be excluded from the EVA.

Our proposal to consider additional revenues is the following:

- (b): revenues from ancillary services. Our proposal is to make an average estimation of the total ancillary revenues for the expected volume such as also done in the previous Adequacy and Flexibility study (see page 85) and distribute it over all types of capacities; or pre-define some capacities providing ancillary services and estimate their revenues (in such case only some capacities will get the additional revenues), to the extent that such revenues could actually constitute an actual extra revenue and are not the result of a pure arbitrage decision. The choice between one or the other will depend on the availability of data and computational possibilities;

- (c): revenues from other services such as heat. Such revenues are mainly related to CHPs. Our proposal is to consider existing CHPs as 'policy driven' capacities based on the pre-defined scenario capacities (following article 6, paragraph 3 of the ERAA methodology) unless there are known risks that those capacities will be decommissioned. The reason for such choice is that it is very complex to assess the other CHP revenue streams in details (without having a complete heat & electricity model). Indeed, there are different industrial processes, heat supplies, way of operating the unit… and for each type of processed supplied, a different assumption will need to be taken into account. Unfortunately, such data and estimations of revenues is according to us not possible to be quantified. The existing CHPs would then be excluded from the EVA loop (in all countries) unless stakeholders indicate that some of the units might be at risk (subsidies, end-of-life …). An ex-post qualitative assessment could happen based on market revenues for the units not part of the EVA. New CHPs can be assessed against electricity market revenues only, unless it is known that specific subsidies or policies are already in place that guarantee the amount of capacity in the scenario for the different target years. Such reasoning is also supported by the paragraph 9 (d) in the ERAA methodology where it is indicated that when expected revenues streams from subsidies are known, the capacities may not be taken into account in the EVA. In addition, it is also indicated in paragraph 3 that the EVA may abstain from considering the capacity resources based on exogenous assumptions according to the baseline national data.
- (d) Capacities receiving subsidies may be removed from the EVA. We propose therefore not to assess the EVA of renewable capacities unless it is known that the subsidies schemes are to be cancelled in the future. This could be the case for certain type of biomass in Belgium (or its regions) or in other countries, hence in that case we propose to consider those capacities as part of the EVA without subsidies (when the expected cancellation is known).
- (e) Concerning expected revenues from CMs, the countries which have CMs approved and in place for the different target years assessed in this study will be calibrated on their reliability standard (e.g. by, as suggested, adding revenues coming from the CM). Such reasoning was already applied in the previous study (see page 63).

5.6. Type of capacities to be monitored by the EVA

As a summary of the previous paragraph, we propose to consider in the EVA the following capacities:

- Existing and new thermal units while respecting policy targets for some generation types (such as coal/lignite or nuclear capacities);
- New "in the market storage" facilities (on top of installed capacity in 2020);
- New "pumped-storage" facilities (on top of installed capacity in 2020);
- New DSR capacities (on top of the proven capacity in 2020);

- Existing and new RES (if no subsidies or no support schemes are known or in place, or if those are to be phased out);
- Existing CHPs (only if there are indications that there are risks that certain units could be closed);
- New CHPs (on top of the 2020 installed capacity and if there is no guarantee that a subsidy scheme will be installed or capacity will be built in the future).

Note that not all possible types will be taken into account for all time horizons; indeed, in some cases additional constraints could be added such as a maximum capacity potentials or the time to develop/build new capacities.

5.7. Extensions of the EVA to other countries

If computationally feasible, the EVA will be applied to several countries at once. This is a major improvement and a major challenge for the EVA algorithm and underlying complexity. The intention is to envision an application of the EVA to Belgium and at least its neighbors. If this is concluded not to be computationally feasible, a fall-back solution could be an ex-post assessment of the viability abroad or a manual EVA such as suggested in paragraph 18 of Article 6 of the ERAA methodology.

5.8. Extensions of the EVA to more target years (multiyear assessment)

The EVA will be performed on each target year of the study.
Unfortunately, it is impossible (for this study) to perform a multi-year assessment of the economic viability (computationally and algorithmically such approach would require to exponentially increase the amount of simulations), hence the results will be provided target year per target year. It is important to note that, as explained in the EVA metric, the lifetime of the unit would be taken into account, but the expected revenues over the lifetime are taken from the simulated revenue distribution for the target year. The consistency between the results between the different target years will also be assessed.

5.9. Amount of Monte-Carlo years for the EVA

In order to make the EVA exercise computationally feasible, we aim to perform it on a reduced set of Monte Carlo years (or 'future states') while remaining sufficient to ensure representativeness of market revenues and other economic indicators assessed. Such approach was already applied in the previous study (as explained on page 92). A check will be performed to demonstrate that the chosen amount of MC years is statistically representative (for the indicators assessed in the EVA) compared to the full MC set used to derive the security of supply indicators.

6. Flexibility and balancing reserves

In the previous methodology, as described in Section 3.4.3.1 of the Adequacy and Flexibility study 2019, the adequacy simulations took into account upward fast flexibility requirements during periods with scarcity risk. This ensured the availability of flexibility to allow BRPs to balance their portfolio, and the TSO to cover the residual imbalances, even during tight system conditions. However, the ERAA methodology does not provide a framework to model the total flexibility to be provided by BRPs and TSOs, but only allows to model the TSO's reserve capacity requirements according to Article 4(6)g of the ERAA methodology:

"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, either by deducting their respective capacities from the available supply or by adding them to the demand profile. However, the modelling of FCR and FRR shall comply with Article 7(7).*

iii. *RR shall be considered as capacity resource available in the ED. For each target year, the dimensioning of RR shall be consistent with Article 160 of SO GL."*

The balancing capacity for FCR reserved by Elia is determined by all TSOs of the synchronous zone in application of the provisions of Article 153 of the European guidelines SOGL, for which the methodology is specified in the Synchronous Area Operational Agreement (hereafter referred to as SAOA)[4]. In contrast, FRR is dimensioned on a daily basis by Elia in line with Article 157 of the European guidelines SOGL, and further specified in Elia's LFC block operational

[4] When drafting the SAOA for RG CE, the TSOs considered that it was advantageous to extend the minimum content of the SAOA required by the SOGL with additional content based on the previous operational handbook of ENTSO-E, the Network Code on Electricity Emergency and Restoration and EBGL. The extended SAOA, as described above, shall be referred to as the Synchronous Area Framework Agreement (SAFA). **https://transparency.entsoe.eu/system-operations-domain/operational-agreements-of-synchronous-areas/show**

agreement[5]. Note that FRR are further split into aFRR (full activation time of 7.5 minutes) and mFRR (full activation time of 15 minutes). Note also that currently no RR are determined or contracted in the Belgian LFC block.

As reserve requirements are only determined year-ahead (FCR) or day-ahead (FRR), long-term estimations have to be made towards 2032 to be used for this study. These estimations will be based on an extrapolation and interpolation of current values, available projections (cf. Elia's study on additional installed offshore capacity on the balancing of the system and to formulate recommendations)[6]. Note that this remains an estimation as the final reserve requirements on FCR are calculated on a yearly basis by ENTSO-E and the FRR requirements on a daily basis by Elia. Therefore, they depend on the final generation mix, as well as the performance of the BRPs to balance their portfolio. The provided projection can therefore never be interpreted as a target.

As the current modelling framework for the adequacy assessment is based on a "perfect foresight" principle, it does not allow to model the use of balancing reserves in relation to unforeseen imbalances (in line with Article 4(1)g). Therefore, these balancing reserves are deducted from the available capacity resources in the economic dispatch, and this by deducting their respective capacities from the available supply. For this, the capacity will be assumed to be allocated to a representative mix of demand, generation, storage and cross-border capacity.

In conclusion, in order to be compliant with the ERAA methodology, Elia proposes to replace the former approach where flexibility needs are modelled in the adequacy assessment, by an alternative approach where the reserve capacity requirements on FCR and FRR are modelled. Note that this modification does not impact the calculation of the flexibility needs (determine all flexibility needs required after day-ahead market closure for the entire system) and assessment of the flexibility means (assess available flexibility resulting from the unit's generation, storage and demand schedules in the adequacy simulations), which are not impacted by the ERAA methodology. A graphical representation of the flexibility method is given in Figure 7.

[5] **https://transparency.entsoe.eu/system-operations-domain/operational-agreements-of-load-frequency-control-blocks/show**

[6] **https://www.elia.be/en/public-consultation/20201001-public-consultation-on-integration-of-additional-offshore-capacity---mitigation-measures**

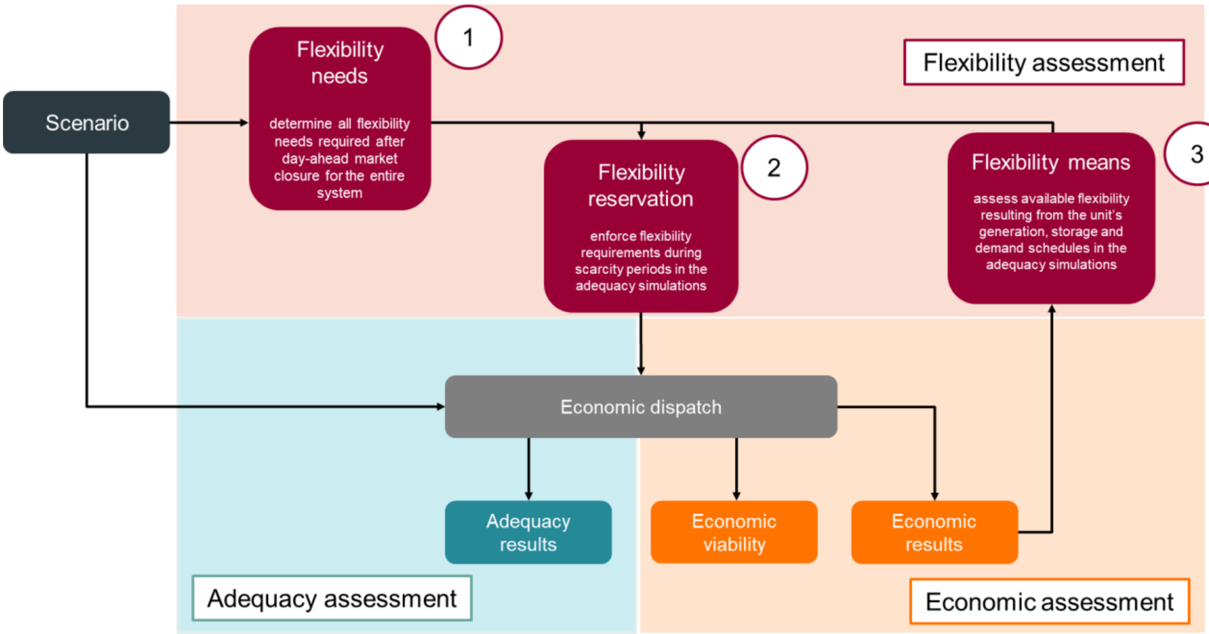

Figure 7: Graphical representation of the flexibility assessment in relation to the adequacy assessment

7. Convergence of adequacy results

In order to comply with ERAA methodology, Article 4, paragraph 2 (e) (f) (g), we propose to add a convergence indicator such as specified in those paragraphs. The amount of MC years used for adequacy simulations will therefore depend on the convergence of the variation of the EENS metric. The following figures (8 and 9) taken from the ERAA methodology illustrate the type of indicator that will be calculated and monitored.

$$\alpha_N = \frac{\sqrt{Var[EENS_N]}}{EENS_N}$$

where $EENS_N$ is the expectation estimate of ENS over N, the number of Monte Carlo years, i.e., $EENS_N = \frac{\sum_{i=1}^{N} ENS_i}{N}, i = 1 \dots N$ and $Var[EENS_N]$ is the variance of the expectation estimate, i.e. $Var[EENS_N] = \frac{Var[ENS]}{N}$.

Figure 8: Convergence criteria

$$\frac{|\alpha_N - \alpha_{N-1}|}{\alpha_{N-1}} \leq \theta$$

then increasing the number of Monte Carlo years would not increase the level of accuracy considerably. Consequently, the Monte Carlo analysis can stop.

Figure 9: Convergence criteria

8. Cross border exchange capacity modelling

The proposal is to model interconnections as they are used (or expected to be used) in the day-ahead market coupling mechanism. The countries within the flow-based perimeter are therefore modelled using the flow-based (FB) methodology. Such approach was already used by Elia for several years in its adequacy studies and is compliant with the ERAA methodology. Elia proposes to further take the different developments expected in the capacity calculation methods such as the inclusion of new countries or rules following regulations into account.

Other aspects concerning HVDC outages, exchanges with non-modelled countries and rules for the capacity calculation method are also explained below.

Flow-based domains

Belgium is currently electrically interconnected to France, the Netherlands, Great-Britain (through Nemo Link®) and Luxembourg (part of the Elia control zone for the Sotel/Twinerg grid). By the end of this year also the ALEGrO HVDC interconnector with Germany will be operational.
In order to comply with the Clean Energy Package and to fully assess the adequacy situation of Belgium, given these changes, a flow-based framework has been set up which builds on the methodology already presented in the previous study or in the studies assessing the volume of strategic reserves for next winters. Additionally, the same systematic approach as used in previous assessments will be followed, linking specific combinations of climate conditions for wind and load with the representative flow-based domains to be considered in the simulations.
The flow-based model was improved to extend it to the whole CORE region and to allow 'advanced hybrid coupling' for external links linked to the flow-based zone. Those developments add significant complexity to the calculations of the domains and to the economic dispatch simulations to be performed.

Fixed commercial exchange capacity between Market zones outside the flow-based region

For countries outside of the flow-based perimeter, the interconnectors will be modelled on the basis of values of the bilateral commercial exchange capacity between countries. The import and export capacity available for commercial exchanges, also referred as Net Transfer Capacity (NTC), is calculated by the concerned Transmission System Operators (TSOs). The NTC values are calculated based on the technical characteristics of the lines and the internal limitations of each TSO. Those assumptions will be taken from the latest ENTSO-E database used for the MAF2020 study.

Fixed commercial exchange capacity between the market zones outside of the flow-based region and the flow-based region

The interconnections between the countries of the flow-based region and the rest of Europe are modelled using a commercial exchange capacity also referred to as Net Transfer Capacities (NTC). In 'advanced hybrid coupling' those links will be taken into account as variables in the flow-based domain calculation.

HVDC outages

Availability of the HVDC system elements will be included in the simulation as random outages and in line with Article 6 and paragraph (f) of the ERAA methodology. Random outages are represented by the parameter 'Outage Rate (OR)', which in this case defines the annual rate of outage occurrences of HVDC systems. Those situations are simulated by random occurrences of outages within the probabilistic Monte Carlo scheme, while respecting the annual rate defined. This assumption is further detailed in the Excel file attached to this public consultation.

Exchange with non-modelled countries

No exchanges between the countries that are modelled and those that are not modelled are considered. Important to note is that a significant amount of new countries is proposed to be added in the simulation perimeter which now covers most of European countries. Since the geographical perimeter considered around Belgium is significant, the effect of the abovementioned assumption has little impact on the adequacy situation in Belgium.

Rules applied to the capacity calculation method

The different capacity calculation rules (such as the minRAM, the perimeter of the flow based region…) proposed for this study are detailed in the Excel file attached to this public consultation for each target year.

9. Out of market capacities

'Out of market capacities' for Belgium (cf. definitions (bbb) and (oo) in the ERAA methodology) for this study are considered as 'strategic reserves'. Those 'out of market capacities' are to be dispatched (if present/contracted/available) for each country after the market and can therefore only impact the LOLE/EENS of the given country without affecting the neighboring ones; neither do they affect the market prices and revenues. If such Strategic Reserve mechanism is present in Belgium, and following Article 7, paragraph 11, the results will be provided with and without those capacities.

Concerning Article 7, paragraph 7 and definition (oo) of the ERAA methodology, strategic reserves are to be dispatched when a TSO is “likely to exhaust” the balancing resources. The “likely to exhaust” accounts – as mentioned in the electricity regulation on this topic - for the fact that strategic reserves can have operating requirements and ramping constraints less flexible than balancing resources. Indeed, strategic reserves typically have longer start-up times than balancing reserves (i.e. typically up to a few hours compared to much shorter time frames around 15 mins (or shorter) for balancing resources). In the foreseen modelling setup with perfect foresight (as is the case in the ANTARES modelling setup used for this study), this implies that strategic reserves – when contracted/available/… - are to be assumed to be activated prior to balancing resources. As mentioned in the part related to flexibility, the balancing reserves are as well deducted from the capacity available in the market given that the economic dispatch model used for this study is ‘perfect foresight’.

10. Price limits in the electricity market

Following article 7, paragraph 9(a) of the ERAA methodology, we propose to develop a method where the price limit on the electricity market will evolve in the simulations when prices in the simulations are reaching the price cap at least once in a simulated year. The proposal is therefore to apply this rule on a yearly basis, hence an increase of +1000 €/MWh will be applied on the price cap of all market zones (the starting price cap will be set to 3000 €/MWh) if at least one market zone in the CORE region reached 60% of the price cap during the previous simulated year.

If in the realization phase, it results that this method is not possible to be implemented, sensitivities could also be applied with different price limits such as already done in the previous study.