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Assessment of underlying capacity mechanism studies for Greece

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Title Assessment of underlying capacity mechanism studies for Greece

Abstract
The increased electricity production from variable sources in the EU combined with the overall decline in demand in recent years, have raised concerns about the security of electricity supply, in general, and in particular about generation adequacy and flexibility, prompting some Member States to consider new public interventions, the so-called capacity remuneration mechanisms. This work presents a review of the underlying capacity mechanism studies for Greece based on European best practices to highlight the latest developments and current trends.

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Contents

Executive summary

Policy context

The climate change and energy policies of the European Union (EU), and the initiatives towards a low-carbon electricity production, have had profound implications on the manner in which the electricity sector is organised and the roles of market actors, especially consumers. However, the increased electricity production from variable sources in the EU, combined with the overall decline in demand in recent years, the need to finance the upgrading of today's aging electricity generation system, the volatility in primary energy markets, and the economic and financial crisis, have created uncertainties for generators with regard to their expected revenues, thus, weakening the financial position of many companies. These issues have raised concerns about the security of electricity supply in general, and for **generation adequacy** in particular, which is the ability of the power system to meet demand in the long term. As a result, some Member States have considered new public interventions, such as support schemes for investments in new electricity generation capacity, or remunerating existing plants to remain operational, the so-called **capacity remuneration mechanisms**. Therefore, an objective identification of the additional capacity needed to achieve the target level of security of supply allows the implementation of efficient and effective procedures to ensure adequacy in Member States. Furthermore, due to the increased penetration of renewable energy sources and their stochastic nature, the need to assess the **flexibility** of the system (capacity of the system to cover fast and deep changes in the net demand) were prominently featured in the last few years.

Within this context, the harmonization of the Greek electricity market with the provisions of ENTSO-E Network Codes is necessary to achieve coupling with the other European wholesale electricity markets, in accordance with the “Target Model”. Towards this goal, the Hellenic State has to implement significant energy reforms, including the adaption of the national electricity market to the **EU Target Model** by the end of 2017. In addition, the Hellenic authorities, taking into account the conditions of the domestic electricity market, the needs of the system in the short and long term, and the EU institutional framework, are considering establishing an auction-based capacity mechanism.

In this context, Directorate-General Joint Research Centre (hereafter JRC) of the European Commission (EC) is providing technical support on the necessary regulatory reforms by the Hellenic Republic for its electricity market to comply with the EU Target Model. This report relates to the following two topics: "*Assessment of the TSO's adequacy study, underlying the capacity mechanism proposal, and its compliance with the ENTSO-E standards*" and "*Technical assistance on defining the methods and criteria of potential study of flexibility requirements to be performed by ADMIE, based on similar studies by other TSOs*".

Key conclusions

One of the five dimensions of the EU’s Energy Union, in relation to the power sector, is security of electricity supply. This objective has several perspectives, one of which is system adequacy which refers to the presence of sufficient resources and transmission capacity to meet the load within a system, whether under normal or unusual conditions (unavailability of facilities, unexpected high demand, low availability of renewable resources etc). In general, the interest in power system flexibility has increased in recent years due to the increased penetration of variable, limitedly predictable, RES generation technologies (mainly wind and solar) as a result of decarbonisation policies. Therefore, an objective identification of the adequacy and flexibility of the system is needed to provide the right investment signals so as to avoid over or under capacity and inappropriate flexible generation. Studying the generation adequacy and assessing the flexibility of a system is a complex undertaking. There are many input data uncertainties, several of those not under the control of the transmission system operator (TSO), therefore, as it is common practice in other TSOs, it is important to conduct a public consultation prior to the official release of such studies.

Approaches to generation adequacy assessment vary between countries, not only with regard to the implemented methodology, but also with regard to the generation and demand models used to estimate these elements. Furthermore, the results are very sensitive to the assumptions used to project future resources and demand(s).

In this context, there is a need for harmonisation of models, data assumptions, and inputs between national and European adequacy and flexibility studies. Best European and international practices based on the current and future evolution of the power system, should be adopted and implemented to provide a common assessment methodology for the pan-European and national adequacy studies.

Main findings

ADMIE, the Hellenic electricity transmission system operator (TSO), submitted to the Hellenic Regulatory Authority for Energy (RAE) its latest generation adequacy report in 2016, which covers the period 2017-2023. In December 2016, ADMIE also submitted an investigation on flexibility needs, after a request from RAE, as an addendum to the aforementioned generation adequacy assessment. In this report, JRC reviews the methodologies implemented by ADMIE to identify strengths and weaknesses, by comparing them with those of the European Transmission System Operators for Electricity (ENTSO-E) and the Belgian TSO (Elia) on which ADMIE based its flexibility study.

Following the assessment of the studies, the main recommendations for potential improvements are summarised below. It should be mentioned that to achieve full alignment with the ENTSO-E standards on generation adequacy studies or the state-of-the-art on flexibility assessment, the implementation of (at least) these methodological suggestions is needed. Furthermore, it’s imperative that all data is of high quality.

Generation Adequacy

The following actions are recommended to improve the adequacy analysis:

Input data and assumptions

1. The demand scenarios should be associated with their corresponding probabilities. Even with the currently used methodology, these could be reasonably described and taken into account, for example, by using the demand time series generated in the Monte Carlo analysis of ENTSO-E's Mid-term Adequacy Forecast (MAF) after applying the climatic effect to the normalised load. This process would ensure the consistency of load assumptions and enable the assignment of a probability to the "low/medium/high" demand scenarios used in the analysis of ADMIE.
2. The effect of hydro production has a very high impact on the Greek system adequacy indicators. It is not clear how well the hydro conditions used in the MAF coincide with the Greek hydro conditions. ADMIE and ENTSO-E should reinforce their collaboration to ensure the consistency of the hydro scenarios in the Southeast region.
3. Input datasets used for assessing the Greek adequacy situation by ADMIE and ENTSO-E should be aligned to the highest extent possible, to allow comparison and complementarity. The differences, if any, should be clearly identified and (ideally) an indication on how they affect the results should be provided.
4. A more detailed evaluation of the contribution of interconnectors based on a statistical analysis of the results of ENTSO-E's MAF, could be conducted, if these

are considered robust enough. While this information is not public, we assume that they are available to ADMIE.

5. The impact of CCGT de-rating should be included in the ADMIE's study.
6. The potential benefits of demand response should be included in the adequacy study by ADMIE.
7. Where an adequacy assessment is used to justify the need for a major market intervention like a capacity mechanism, it should also take into account the potential impact of beneficial market reforms and the extent that these can reduce the need for intervention.

Methodological recommendations

The following methodological improvements should be considered for next versions of the adequacy study of ADMIE, and are based on European and international best practices:

1. Use probabilistic approaches (e.g. sequential Monte Carlo) to consider all stochastic aspects of RES, hydro, and temperature, in a more realistic chronological manner, taking into account their spatial-temporal correlation. This would also enable a more robust approach on overall hydro optimization compared to the peak shaving applied by ADMIE, and the inclusion of the technical constraints of the thermal units. (MAF, Elia)
2. Use structural blocks instead of specific technologies to solve adequacy and flexibility issues, as TSOs should primarily identify needs and not necessarily solutions. (Elia)
3. An analysis of the forecasted operating profile of the resources required to maintain the reliability standards is an essential step to enable the timely implementation of the required market changes. This could be used as an input for the assessment of the economic viability of the generation mix. (Elia)
4. The adequacy study should be complemented with an analysis of the impact of fuel availability.
5. The studies of ADMIE could be significantly improved by linking adequacy/flexibility analysed scenarios to the Ten-Year Network Development Plan (TYNDP) Visions of ENTSO-E (scaling them up at the target year). For short term analysis (e.g. until t0+5), it could be possible to aggregate more Visions in one scenario. On the other hand, specific aspects can be more relevant at national level, potentially increasing the number of analysed scenarios. This should be clearly described by TSOs in the explanation of the scenarios analysed in national studies. This approach could save time, resources and ensure comparability and complementarity of studies in different time horizons and/or geographical level.
6. The interconnected islands' load and generation facilities should ideally be represented as a different area to better model the interconnection flows (e.g. Crete).
7. It's suggested to improve the methodological approach concerning the growth demand forecast (e.g. GDP correlation with demand, population growth, demand growth by sector, energy efficiency measures, electric vehicles, etc.).

Flexibility Assessment

Improvements to the flexibility assessment

The flexibility assessment by ADMIE can be improved by following the below recommendations:

1. The aim of a flexibility assessment is to quantify the reserves requirements of the system in order to cope with residual load variability and forecast errors. The study should be extended to provide a robust quantification of the Greek system reserve requirements (FCR, aFRR, mFRR) based on the statistical analysis of the above parameters at hourly and intra-hourly steps in agreement with the draft Regulation of the European Commission on establishing guidelines for electricity transmission system operation.
2. Currently, the statistical analysis is applied on the one climatic year that ADMIE has used in the current analysis. However, it's recommended to extend this by using climatically adjusted load and RES production time series generated in the MAF for Greece, to consider the climatic impact(s).
3. A qualitative and quantitative analysis should identify how the future reserve requirements identified previously will be served. (Which are the potential resources that are expected to be available to provide the reserves? Will they be adequate? If not, what actions are required?).
4. It is recommended to investigate and report on the causes of the inconsistency observed between historical data and projections of load variability to rule out biases or errors.

Methodological recommendations

The following methodological improvements should be considered for next versions of the flexibility study, and are based on European and international best practices:

1. In conjunction with a sequential Monte Carlo analysis for adequacy, market simulations could determine whether the system has adequate resources to cope with hourly and 3-hour ramping requirements.
2. The report should be complemented with an analysis of the operating profile of the resources required to provide reserves. (Elia)
3. A coherent discussion on the outcomes of the flexibility assessment analysis and their relation to the long-term planning process of the Greek power system should be provided. (Elia)
4. A coherent investigation of the contribution of flexibility sources such as variable RES, demand response, and interconnections should be conducted, based on market simulations. (Elia, NREL)

1 Introduction

1.1 Context

The climate change and energy policies of the European Union (EU), and the initiatives towards a low-carbon electricity production, have had profound effects on the manner in which the energy sector is organised, and the roles of market actors, especially that of consumers.

The on-going EU Energy Union strategy consists of five closely related and mutually reinforcing dimensions:

- **security, solidarity and trust**, diversifying Europe's sources of energy and ensuring energy security through solidarity and cooperation between Member States;
- **a fully-integrated Internal Energy Market (IEM)**, enabling the free flow of energy throughout the EU through adequate infrastructure, without technical or regulatory barriers, providing efficient means to increase security of supply;
- **energy efficiency**, which reduces dependence on energy imports, cuts emissions, and drives jobs and growth;
- **economy decarbonisation**, enforcing important European and national targets in terms of greenhouse gases emissions and making EU the world leader in renewables. This commitment has been further strengthened by the EU ratification of the recent COP-21 (Paris) agreement;
- **research, innovation and competitiveness**, supporting breakthroughs in low-carbon and clean energy technologies driving the transition of the energy systems and, at the same time, improving competitiveness.

Concerning the electricity sector, the completion of the IEM and the implementation of the so-called "Target Model" for electricity are expected to lead to the development of liquid electricity markets, both short and long-term, by increasing the markets' ability to dynamically provide the most cost-efficient development of the European electricity system by making optimal use of common resources.

However, increased electricity production from variable sources in the EU combined with the overall decline in demand in recent years, the need to finance the upgrading of today's aging electricity generation system, volatility on primary energy markets, and the recent economic and financial crises, have created uncertainties for generators with regard to their expected revenues, thus, weakening the financial position of many companies. These issues have raised concerns about the security of electricity supply in general, and for generation adequacy in particular.

The above facts coupled with the liberalisation of electricity markets and their increased integration into a single internal electricity market, have created challenges for ensuring generation adequacy. In a competitive internal electricity market with multiple producers and unbundled network operators, no single entity can by itself ensure the reliability of the electricity system any longer. Therefore, the role of public authorities in monitoring and ensuring security of supply, including generation adequacy, has become more important.

As a result, concerns about the adequacy of generation capacity have led some Member States to consider new public interventions, such as support schemes for investments in new electricity generation capacity, or remunerating existing plants to remain operational. Therefore, an objective identification of the additional capacity needed to achieve the target level of adequacy allows the implementation of efficient and effective reforms and procedures to ensure adequacy in Member States.

As explained in CIGRE' (1987) [1]:

> "*Adequacy is a measure of the ability of a bulk power system to supply the aggregate electric power and energy requirements of the customers within component ratings and voltage limits, taking into account scheduled and unscheduled outages of system components and the operating constraints imposed by operations.*"

However, the optimal or desirable adequacy level should represent a balance between investments and the cost of energy not served, to avoid over (or under) capacity and provide the right investment signals. In fact, achieving "absolute" adequacy would require investment expenses substantially above the achievable benefits. In addition, apart from generation sources, essential elements that should be taken into account for the assessment of adequacy include cross-border interconnections, electricity storage, and demand response.

Furthermore, due to the increased penetration of renewable energy sources and their stochastic nature, in recent years there has been an ever increasing need to assess the flexibility of the capability of the system to cover fast and profound changes in the net demand, which is the load demand minus non-dispatchable energy generation (mainly wind and solar).

Within this context, the harmonization of the Greek electricity market with the provisions of the Network Codes of the European Network of Transmission System Operators for Electricity (ENTSO-E) is necessary to achieve Europe-wide coupling of European wholesale electricity markets, in accordance with the "Target Model". Towards this goal, the Hellenic State has to implement significant energy reforms, including the adaptation of the Hellenic electricity market to the EU Target Model by the end of 2017 (Hellenic Law 4336/2015). Consequently, the Hellenic Parliament recently voted the "Target Model law for the Hellenic State" (Law 4425/2016) which provides the general framework for the implementation of the Target Model in the Hellenic wholesale market.

The Hellenic authorities envisage the creation of a Forward Market with forward contracts on electricity, both Over-The-Counter (OTC) and centrally-traded (organized Forward Market), a reformed, energy only Day Ahead Market, an Intra-day Market, and a Balancing Market, which are the fundamental aspects of the EU Target Model. Compliance with the Target Model will also require that ADMIE, the Hellenic transmission system operator (TSO), implements a series of operational procedures relating to market coupling in the Day-Ahead and the Intraday Markets.

In addition, the Hellenic authorities, taking into account the conditions of the domestic electricity market, the needs of the system in the short and long term, the EU institutional framework [2], the commitments of the Hellenic Republic resulting in particular from Law 4336/2015, and the conclusions as reflected in the "Final report of the sector inquiry on capacity mechanisms" of the European Commission [3], are considering establishing an Auction-based Capacity Mechanism.

The Joint Research Centre (JRC) is providing technical support on the necessary reforms needed so that the Greek electricity market complies with the EU Target Model.

1.2 Legal framework

The high-level legal framework relevant to generation adequacy can be found in article 8 of the Council Regulation (EC) No 714/2009 which states that:

> "*3. The ENTSO for Electricity shall adopt:*
>
> *…*

(b) a non-binding Community-wide ten-year network development plan, (Community-wide network development plan), including a European generation adequacy outlook, every two years;

…

(f) annual summer and winter generation adequacy outlooks.

4. The European generation adequacy outlook referred to in point (b) of paragraph 3 shall cover the overall adequacy of the electricity system to supply current and projected demands for electricity for the next five-year period as well as for the period between five and 15 years from the date of that outlook. The European generation adequacy outlook shall build on national generation adequacy outlooks prepared by each individual transmission system operator."

ENTSO-E publishes two seasonal adequacy outlooks, the winter and the summer outlook, focusing on the short-term adequacy of the European interconnected electricity system. Both of them analyse potential risks to system adequacy for the whole ENTSO-E area for the next six months, and provide a review of what happened in the previous six months in comparison with the previous seasonal outlook.

In addition, ENTSO-E has published the mid to long-term European generation adequacy forecast ("Scenario Outlook and Adequacy Forecast", SO&AF), with a time horizon of 15 years in SO&AF 2014, and 10 years in SO&AF 2015. Although European legislation mandates that a generation adequacy forecast is compiled every two years, ENTSO-E has decided to make it an annual publication, due to its relevance to decision makers and stakeholders. In the summer of 2016, ENTSO-E published its first Mid-Term Adequacy Forecast (MAF) report [4] replacing the previous Scenario Outlook & Adequacy Forecast (SO&AF). The 2016 MAF presents the first pan-European assessment of generation adequacy using market-based probabilistic modelling techniques, and will be presented in a latter section.

Regarding the role of national public authorities in ensuring security of supply, EU legislation (Directive 2009/72/EC for the internal market for electricity) mandates that each Member State monitors their security of electricity supply, which includes generation planning within their national market, over the medium to long-term, covering the balance of supply and demand and the level of expected future demand.

This EU Directive has been transposed to Hellenic Republic legislation with Law 4001/2011. For generation adequacy, article 95, paragraph 4 of the aforementioned Law states that the Greek electricity TSO shall publish a special study of capacity adequacy and reserve margin adequacy, taking into account the ten-year Greek electricity transmission system development programme, and the long-term energy planning in Greece. ADMIE submitted to the Hellenic Regulatory Authority for Energy (RAE) its first generation adequacy report in 2013, covering the period 2013-2020. The most recent generation adequacy report was published in 2016 [5] covering the period 2017-2023.

It is worth mentioning that the European Commission (EC), on the 30th of November 2016, presented a package of measures to keep the European Union competitive, entitled "*Clean Energy for All Europeans – unlocking Europe's growth potential*" [6]. In addition, the EC has published a report of its state aid sector inquiry into electricity capacity mechanisms in the EU. The presented package will complement the state aid rules, thus creating a European legal framework for capacity mechanisms, introducing concrete rules for cross-border participation and leading to the integration of capacity markets.

The main conclusions from the sector inquiry of the EC [3] are provided below:

1. It has become clear that despite current overcapacity in the EU as a whole, there are **widespread concerns that insufficient generation capacity** will remain in the market or will be available in the future to provide adequate security of supply.

2. **Electricity market reforms are indispensable** since they help to address concerns about inadequate security of supply. However, most Member States have yet to implement appropriate reforms. The Commission's Clean Energy for All Europeans Package proposes a number of reforms to improve the functioning of EU electricity markets and the Commission will require from Member States to implement reforms that accompany plans to introduce any capacity mechanism. Examples of key reforms put forward by the package are the removal of price caps on the wholesale market and the reform of short term markets, which will be made more flexible and responsive to the rise in variable renewable generation.
3. Even in a reformed market, **uncertainty may persist as to whether an increasingly volatile market price and rare scarcity situations can drive long-term investment decisions.** Some Member States have therefore decided to introduce capacity mechanisms to ensure security of electricity supply. The Commission will examine in particular whether Member States have demonstrated the necessity of the proposed capacity mechanism and whether there are appropriate measures in place to minimise the distortions of competition that they generate, taking account the outcome of the sector enquiry.
4. **A rigorous adequacy assessment** against a well-defined economic reliability standard is crucial for identifying risks to security of supply and for determining the necessary size of any capacity mechanism. This will significantly reduce the risk of over-procurement and help limit the distortions of competition that capacity mechanisms create. Further EU harmonisation of adequacy assessments will help to increase transparency and build confidence in their results. The Commission's Clean Energy for All Europeans Package therefore proposes to develop an enhanced EU-wide adequacy assessment methodology and annual adequacy assessments to be conducted by the European Network of Transmission System Operators for Electricity (ENTSO-E).
5. **The type of capacity mechanism chosen should address the problem identified**. Whatever the mechanism chosen, it should be regularly reviewed to check that there is a continued need for it.
6. Capacity mechanisms should be **open** to all types of potential capacity providers. This, combined with a **competitive price-setting process**, ensures that too much is not paid for capacity. The only exceptions are specific mechanisms for demand response, given their particular suitability for addressing underlying market failures, and strategic reserves, with the caveat that they should not promote new generation capacity to minimise market distortions.
7. Market wide capacity mechanisms must be open to **explicit cross-border participation** in order to minimise distortions to cross-border competition and trade, ensure incentives for continued investment in interconnection and reduce the long-term costs of security of supply on a national and European level.

In addition, the adequacy assessment, used to identify the need for a capacity mechanism, should also take into account the potential impact of beneficial market reforms and the extent that these can reduce the need for intervention. Furthermore, it is mentioned that the EC will continue to work to bring existing capacity mechanisms in line with State aid rules, and assess new plans of Member States to introduce capacity mechanisms, in light of the insights gained from the sector inquiry.

1.3 Methodologies

Assessing the generation adequacy of the power system comprises of data regarding electricity supply (generators availability, RES production etc.), assumptions on the evolution of demand, and a calculation procedure. The main approaches used for the calculations fall in two main categories, deterministic and probabilistic. Depending on the adopted approach, different metrics for measuring a power system's adequacy can be adopted.

What follows is a short description of these categories. More information can be found in the relevant bibliography [7], [8].

Deterministic

The deterministic methodology has been used extensively by utilities and TSOs. This approach was adopted in the past by the Union for the Coordination of the Transmission of Electricity (UCTE), and subsequently by ENTSO-E to assess generation adequacy [9]. Deterministic models are essentially scenario-based contingency calculations, thus, only a small set of chosen conditions of the power system can be assessed. They estimate the availability of generation at some point in the future and (usually) compare with an estimate of the peak demands (summer and winter), thus, providing the reserve margin.

This type of methodology generally needs reduced computation time and data management, compared to probabilistic methodologies, but it cannot capture the stochastic nature of the system behaviour and does not assess the likelihood of each outcome.

Probabilistic

The probabilistic methodology can consider the random nature of loads, production of RES, and outages of generation equipment, by modelling the uncertainties associated with supply and demand. The two main approaches used are: analytical (convolution of probability functions) and simulation (Monte Carlo).

Analytical techniques represent the system by a mathematical model, using probability distribution functions for the different elements, and evaluate the reliability indices from this model using direct numerical solutions. They generally require relatively short computing times to provide expectation indices. However, when complex systems have to be modelled, simplifications are frequently required to produce an analytical model of the system.

Simulation techniques, typically referred to as Monte Carlo simulations, estimate the reliability indices by simulating the actual process and random behaviour of the system (it could be the entire system, including generation, transmission and distribution) by applying random number techniques to simulate a wide range of possible states of the system. The method essentially treats problems as a series of real experiments. With these techniques, virtually all aspects and contingencies of a power system could be taken into account, such as random events (outages and repairs of elements), dependent events, load, variations and variations of energy input (hydro-generation and RES production). Simulation techniques can provide a wide range of output parameters, such as complete probability density functions. These techniques can be further classified as non-sequential (random) and sequential. The non-sequential approach simulates the basic intervals of the system's lifetime by choosing intervals randomly. The sequential approach simulates the basic intervals in chronological order. This latter approach is suited to situations where one basic interval has a significant effect on the next interval. One example of such a situation is hydro-generation, where the ability to use water in one interval of time can be greatly affected by how water was used and what was the water infeed. ENTSO-E has implemented this approach in its latest MAF 2016 report. The main downside of a Monte Carlo simulation is that a very large number of simulations are needed for reaching convergence and obtaining reasonable accuracy in the estimation of the metric, since each simulation has the same importance, thus, a good representation of the system can be achieved only with several Monte Carlo extractions.

1.4 Objectives of the report

This report addresses two topics: "*Assessment of the TSO's adequacy study, underlying the capacity mechanism proposal, and its compliance with the ENTSO-E standards*" and "*Technical assistance on defining the methods and criteria of potential study of flexibility requirements to be performed by ADMIE, based on similar studies by other TSOs*".

This report reviews and compares the current methodologies implemented by ADMIE and ENTSO-E (generation adequacy) and Elia (flexibility). It should be noted that the underlying reports by ADMIE required significant effort and technical expertise. This JRC report aims to provide constructive feedback and suggest improvements for future generation adequacy studies of ADMIE.

It should be mentioned that this JRC report mainly focus on assessing the methodologies and the data requirements, and not the actual results provided by the respective studies, as these depend on the used data, assumptions and the methods employed.

1.5 Structure of the report

The structure of this report is as follows. Chapter 2 presents the current generation adequacy methodology implemented by ENTSO-E as provided in the 2016 MAF report [4]. Chapter 3 presents the generation adequacy methodology used by ADMIE [5]. In order to review the methodologies in a consistent manner, the same elements, as given in [10], were used. Chapter 4 compares the methodologies presented in Chapters 2 and 3.

Chapter 5 presents the flexibility assessment methodologies implemented by the Belgian TSO [11], and ADMIE [12], followed by the comparison between the methodologies. Finally, Chapter 6 summarises the main findings.

2 ENTSO-E generation adequacy methodology review

2.1 Introduction

Traditionally, generation adequacy and the related impacts on security of supply, were assessed in correspondence to the point of the highest load. The evolution of the energy generation mix towards a higher presence of fluctuating sources and less conventional fossil fuel generation in the system, required a revision of this approach to identify possible critical situations at different times than at peak demand.

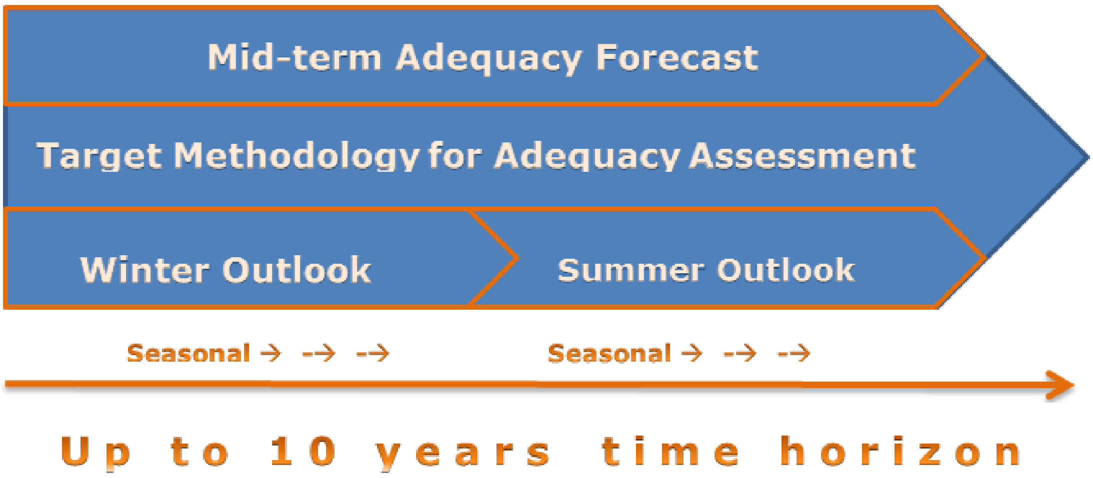
The scope of generation adequacy assessments touches upon the measurement of whether the electricity generation in a system meets the expected technical requirements and energy demand in the future.

With Regulation (EC) 714/2009, the EC mandates ENTSO-E to include a European generation adequacy outlook (art. 7(b)) in the Community-wide ten-year network development plan (TYNDP), and to adopt summer and winter generation adequacy outlook reports (art. 7(f)). Since then, ENTSO-E publishes two main documents, each one targeting a specific time horizon and objectives:

1. Mid-term Adequacy Forecast (MAF) [4][1], which informs investors and policy-makers on the upgrading needs of the generation fleet in relation to potential load-shedding risks. The time horizon covered in this analysis refers to the mid-term (up to 10 years ahead) beyond which the uncertainty on the evolution of the energy system makes any assessment less credible;
2. Seasonal Outlook Reports, divided into a Winter Outlook and a Summer Outlook, which explore the main risks identified within the next seasonal period, i.e. possible very high/low temperatures and other extreme weather conditions.

Finally, the ENTSO-E Target Methodology for Adequacy Assessment presents the overall goal of ENTSO-E in terms of methodology improvements (Figure 1).

Figure 1. ENTSO-E adequacy studies



[1] MAF 2016 [4] replaced the Scenario Outlook & Adequacy Forecast (SO&AF) which focused on mid to long-term assessment of the main risks incurred to the system.

The methodology proposed by ENTSO-E has evolved over the years. The key areas of improvement for the existing methodology are:

- taking into account the new challenges arising from increasing RES integration;
- capturing of more Security of Supply (SoS) risks to the pan-European power system, including the increased need for flexibility;
- providing a better representation of interconnectors and demand side measures.

2.1.1 What is new in MAF 2016

With MAF 2016 [4] ENTSO-E introduces a number of novelties in the generation adequacy assessment:

Modelling approach. ENTSO-E moves from a power balance-based approach (SO&AF 2015) to a market-based probabilistic modelling approach (for a detailed description of the modelling approach see paragraph 2.2);

Geographical scope. The modelling simulation is implemented at the pan-European level and includes 37 countries. Other examples of probabilistic models for generation adequacy assessment had been adopted by some European TSOs[2] and the Penta-lateral Energy Forum[3] (PLEF), but the geographical scope was limited to the national or regional level.

Calibration of results against four different modelling tools. To test the consistency of the results, the simulation was run with four tools, featuring regional differences in power systems across Europe (for a detailed description of the tools see Table 3);

Improved representation of key variables including the temperature sensitivity of load; hydrological analysis; cross-border exchanges; forced outage rates (FOR) for thermal units and (relevant) HVDC interconnectors;

Pan-European Market Modelling Data Base (PEMMDB), a consistent, harmonized and centralized collection of data provided by European TSOs, based on principles set by ENTSO-E (for a detailed description of the data set see paragraph 2.2.1);

The ultimate objective of the modelling effort carried out by ENTSO-E is to set up a consistent methodology at the European level to help define a common framework (data/methodology/results) for further studies at the regional and national levels.

2.1.2 Main simplifications of the methodology

The main simplifications adopted in the methodology can be summarised as:

- market representation through Bidding-Zone (BZ) configurations as congestion free zones or 'copper plate' zones with constant transmission capacities;
- market sensitivity runs including and excluding the contribution of operational reserves have been considered for their impacts on adequacy issues in place of the modelling of intraday trading and balancing;
- no explicit modelling of DSM/DSR has been performed in this report. However, the potentials for load reduction capabilities was collected from TSOs;
- no flow-based market coupling has been modelled in this report. The exchanges obtained in this report through the simultaneous importable/exportable capacities should therefore be understood as 'commercial flows' and not as 'physical flows';

[2] I.e. France [19], Belgium [11].
[3] [24]

- the scenarios analysed in [4] for 2020 and 2025 are based on a best estimate of the evolution of the generation mix (thermal and renewable generation) and transmission capacity as well as demand forecast of each country. No sensitivity analysis was made for any of these factors.

2.2 Methodology

2.2.1 The input parameters and databases

The data for the scenario forecast for 2020 (Expected Progress scenario) was collected in January – February 2016 from the TSOs according to their best knowledge on the evolution of the generation mix in their country. The data for this scenario should be considered as a conjunction point with TYNDP 2016. Differences can be observed due to the fact that TYNDP 2016 data was collected in October-November 2014. Data for the Best Estimate scenario for year 2025 should be understood as ideally mid-term conjunction point for TYNDP 2018, and should be based on TSOs best estimate forecasts of development, following the same logic as used for the MAF 2016 - 2020 Expected Progress scenario but extended to 2025. Note that 2025 data was not collected for TYNDP 2016[4].

Table 1 and Table 2 contain an overview of the data and sources used by ENTSO-E for the setup of the input parameters and the databases.

Table 1. Selected information on the databases used in the modelling runs

Data set	ENTSO-E Pan-European Climate Data Base (PECD 1.0)	Pan-European Market Modelling Data Base (PEMMDB)	IEA "Current Policies" scenarios (year 2020)
Sources	Technical University of Denmark (DTU)	Each individual transmission system operator (TSO), national market parties, generators and national regulatory agencies	IEA World Energy Outlook 2013
Parameters	Load factors, wind speed, solar irradiation, temperatures	For details see Table 2	Fuel prices, CO_2 prices
Type of data	Time series: years 2000-2013	National generation adequacy data and outlooks	Data forecasts for year 2020

The Pan-European Market Modelling Data Base (PEMMDB) contains load factor and temperature datasets (synthetic hourly time series derived from climate reanalysis models) that enable a coherent simulation of variable renewable production and weather-dependent load variation. The currently available time series compiled by the Technical University of Denmark, cover the period of years 2000-2013.

The data provided by the TSOs included in the pan-European perimeter of the model were stored in the PEMMDB (Table 2), while some reference parameters for the scenario analysis come from the IEA forecasts [13].

Table 2. Pan-European Market Modelling Data Base (PEMMDB)

Segment	**Parameter**
Generation	Planned and forced outages of thermal plants
	Minimum stable generation (MW)
	Ramp up/down rates (MW/h)
	Minimum Up and Down Time
Transmission	Adequacy reference transfer capacities values
	Simultaneous importable / exportable capacities
	Availability of HVDC lines

[4] Some of the input data for the modelling and scenarios set up are published along with the MAF 2016 and are available to download from https://www.entsoe.eu/outlooks/maf/Pages/default.aspx under "data package".

Reserves	Net Generation Capacity (NGC) to cover each TSOs' reserve requirements[5]
Potential for load reduction capabilities	Last resort emergency capabilities available to TSOs

2.2.2 The simulation tools

Four European TSOs made their tools available to ENTSO-E. Each tool is designed to capture the features of the national and regional scope of the power system where the relevant TSO operates. All four tools use identical input data and are designed to assess the level of adequacy of the generation in a specific area. Though *"full alignment of the results between different tools is not possible due to differences in the intrinsic optimization logic used by the different tools"* [4].

The tools do not model the market behaviour of the market participants (i.e. their bids and offers strategies; withdrawals from the grid etc.). They rather choose the generating units and their dispatch behaviour by solving a cost minimization problem formulated as a large-scale Mixed-Integer Linear-Programming (MILP) problem, under a number of operational constraints (e.g. ramping, minimum up/down time, transfer capacity limits, etc.), included some degrees of network constraints that differ by tool. They also consider perfect foresight in the Day-Ahead horizon.

[5] In the Base Case simulations, this capacity is considered as not contributing to adequacy (D-1 situation), while in the Sensitivity simulations, this capacity is assumed to contribute to adequacy (real-time situation).

Table 3. Selected details on the simulation tools (ANTARES, BID3, GRARE, PLEXOS)

Tool (owner/user)	**Type of model**	**Interconnected power systems**	**Flexibility**	**Time granularity**	**Hydro**	**Wind and solar**	**Reserves**
ANTARES (RTE)	Sequential Monte Carlo multi-area adequacy and market simulator	At least one node per country, at most 500 nodes for all Europe	Interconnections (with hourly transmission asymmetric capacities and costs)	One year simulation with a one hour time-step	Local heuristic water management strategies at the monthly/annual scales	Historical/forecasted time-series or stochastic Antares-generated time-series	*Not specified*
BID3 by Pöyry Manag. Consult (users Nordic TSOs[6])	Dispatch model for long and short term analysis of the electricity market	BID3 can be used for the economic assessment of interconnectors, outlining flows and congestion rent	DSR, storage, Combined Heat and Power modelling	Sub-hourly modelling with up to 1 minute resolution	Stochastic dynamic programming for reservoir hydro dispatch under uncertainty and to calculate the option value of stored water[7]	Detailed modelling of RES to understand the impact of renewables and requirements for flexibility	Co-optimisation of energy and reserve holding, including inertia, primary, secondary and tertiary.
GRARE by CESI[8] (Terna)	High performance multi-threaded code, integrated in SPIRA application, designed to perform steady-state analyses (e.g. load-flow, short-circuits, OPF, power quality) for medium and long-term studies for large power systems and detailed transmission networks	Unit commitment and Dispatching consistent with transfer capacities, network detail up to 5,000 buses, DC load flow or ATC based approach	DSM	Single year time horizon with a minimum one hour time-step. Weekly independent unit commitment problems and hourly dispatch optimisation.	Reservoir and pumping Hydro optimisation mindful of water value as an opportunity cost for water in respect to other generation sources	Renewable production calculated by a random drawing starting from producibility figures	Operational reserve level evaluation taking account of largest generating unit, uncertainty of load and RES forecast, possible aggregation of Area and fixed % of load.
PLEXOS by Energy Exemplar (used by i.e. National Grid and EIRGRID)	Sophisticated Advanced Mixed Integer Programming (MIP) tool, co-optimises thermal and hydro generation, transmission, and ancillary services given operational, fuel, and regulatory constraints			Applies optimisation across multiple timeframes	Strong hydro generation modelling capabilities to determine: (a) An optimal planning solution in the medium-term; (b) detailed short-term unit commitment and economic dispatch problem with increased granularity.		

[6] Nordic transmission system operators are Statnett SF (Norway), Svenska Kraftnät (Sweden), Fingrid (Finland).
[7] See Figure 23 of [4] for a detailed description of the Iterative process to prepare hydro data.
[8] www.cesi.it/grare

2.2.3 The modelling approach

The analysis is based on the construction of three scenarios for the years 2020 and 2025: a base case and two sensitivity cases. The base case is built without taking into account reserves, the first sensitivity scenario considers that reserves contribute to adequacy, and the second considers forced outages of HVDC interconnections.

Scenario analysis for 2020 and 2025

The scenarios are built upon a combination of climate year, made of a combination of correlated temperature-sensitive load, wind and solar time series, with 3 possible hydro conditions (dry, wet, and normal) and scheduled and non-scheduled unavailability of generating units and HVDC interconnections.

Table 4. Setup of scenario analysis for 2020 and 2025

<table>
<tr><th>Scenarios</th><th colspan="3">Forecasts
(Best Estimate/Expected Progress)</th><th>Monte Carlo</th><th>Sensitivity</th><th>Tools</th></tr>
<tr><td rowspan="3">2020</td><td rowspan="6">Net Generating Capacity (NGC) forecast</td><td rowspan="6">Cross-border transmission capacity forecast</td><td rowspan="6">Annual level of demand forecast</td><td rowspan="3">1000-2000 simulations</td><td>Base case</td><td rowspan="3">ANTARES
BID GRARE
PLEXOS</td></tr>
<tr><td>Sensitivity (1)</td></tr>
<tr><td>Sensitivity (2)</td></tr>
<tr><td rowspan="3">2025</td><td rowspan="3">1000-2000 simulations</td><td>Base case</td><td rowspan="3">ANTARES
BID GRARE
PLEXOS</td></tr>
<tr><td>Sensitivity (1)</td></tr>
<tr><td>Sensitivity (2)</td></tr>
</table>

Stochastic Monte Carlo approach

Each scenario (the base case and the two sensitivities) are composed using different Monte Carlo samples. The different samples are needed to account for all possible combinations of uncertainties that the power system will face in the future (Load × RES × Hydro × Thermal × Cross border capacity factors).

As it is resumed in [4], for each tool and for each forecast year (2020 and 2025) a number N of simulation runs are constructed by the combinations of (Table 5):

- 14 Wind – PV – Temperature climatic year situations
- between 3 and 6 hydrological yearly situations depending on the region
- 200-300 situations for random outages samples of thermal units and HVDC links.

Table 5. Construction of each Monte Carlo year

<table>
<tr><th>Climate years</th><th>temperature-sensitive load</th><th>wind time series</th><th>solar time series</th><th>Hydro conditions</th><th>Forced Outages of thermal units</th><th>Low cross border capacity</th></tr>
<tr><td>2000 – 2013</td><td colspan="3">One combination for each climate year</td><td>Wet
Dry
Normal</td><td colspan="2">200-300 realizations</td></tr>
</table>

For each annual scenario (2020 or 2025) and for each of the above *N* simulation runs, market simulations with hourly granularity of the whole interconnected pan-EU perimeter were performed, resulting into 8760 hours – variables calculated for each simulation run. Two examples of such possibilities are given in Figure 2 that represent two different Monte Carlo samples, where hour 1 identifies a possible adequacy problem and hour 8760 a situation with no expected problem.

Figure 2. Two possible combinations of
Load × RES × Hydro × Thermal × Cross border capacity factors

HOUR	LOAD	RES	HYDRO	THERMAL	CROSS BORDER CAPACITY	
Scenario 2020 Hour 1	Low /High Temp High Demand (Winter/Summer)	Low Wind Low PV	Dry conditions Low hydro production	Low availabil- ity of Thermal generation	Low cross border capacity	
...	...	...	...	...	...	
Scenario 2025 Hour 8760	Moderate Temp Moderate Demand	High Wind High PV	Wet conditions	Normal availa- bility of Thermal generation	Normal cross border capacity	

Source: [4] page 9

In what follows, the main steps for a comprehensive generation adequacy assessment, as shown in Table 6 [10], are discussed.

Table 6. Main steps for a comprehensive generation adequacy assessment

Model of demand	Load
	Weather conditions
Model of supply	Generation
	Renewables
	Demand side response
	Storage
	Cross-borders capacity
Risk assessment	Indicators
Other recommended elements of the assessment	Sources of Flexibility
	Reserves

2.3 Demand

The model of demand is used to forecast the hourly demand (MW) per country for each scenario (2020 and 2025). These projections represent the expected progress of normalized load for each hour of the year.

Traditionally, the model of power demand in generation adequacy studies incorporates the current power consumption trends and estimates its future projections to provide sufficiently differentiated long-term scenarios of consumption. Uncertainties related to future economic growth and policy development regarding energy efficiency are included in the modelling. The indicators that are commonly taken into account are GDP scenarios, population growth, energy intensity of the economy, and the National Energy Efficiency Action Plans (NEEAP).

This 2016 edition of the generation adequacy assessment contains an improved representation of the temperature sensitivity of load. This analysis uses a "normalized" load profile that gives, for every hour of the year, the expected demand based on historical data and on the average historical temperatures observed.

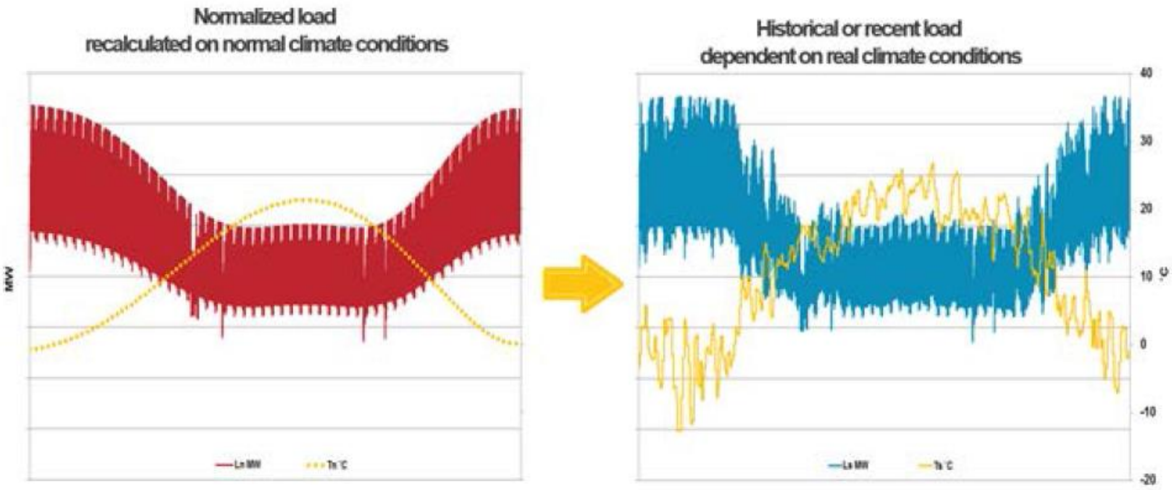
The probabilistic modelling of the power demand in **[4]** incorporates the sensitivity of load to weather changes by identifying three sensitivity zones defined by temperature gradient ($\frac{\Delta L}{\Delta \mathbf{T}} \gtreqless \mathbf{0}$): heating zone $\frac{\Delta L}{\Delta \mathbf{T}} < \mathbf{0}$, cooling zone $\frac{\Delta L}{\Delta \mathbf{T}} > \mathbf{0}$ and comfort zone $\frac{\Delta L}{\Delta \mathbf{T}} = \mathbf{0}$.

This temperature dependency of the load is represented by a linear model that defines the simulated hourly load $L(h)$ (blue curve in Figure 3) as the sum of the load in the normal climate conditions $\mathrm{Lnorm(h)}$ (red curve in Figure 3) and the positive or negative value of the change in the load under temperature changes $\Delta L(\Delta t°\mathrm{C}, h)$:

$$L(h) = Lnorm(h) \pm \Delta L(\Delta t°\mathrm{C}, h) \qquad (1)$$

where the temperature change ($\Delta t°\mathrm{C}$) is the daily average change compared to daily temperature normal. It is worth mentioning that population weighted average temperatures are used.

Figure 3. Load profiles according to simulated climate conditions (blue line) and normalized climate conditions (red line)

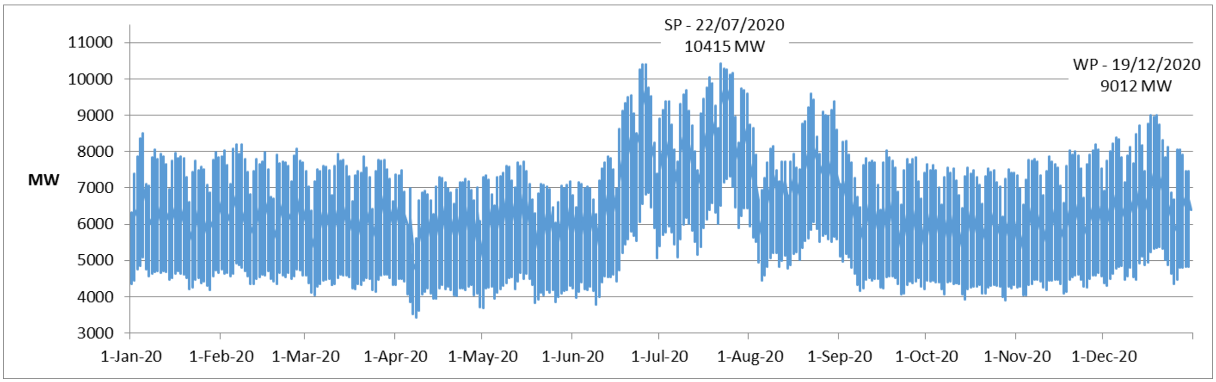


Source: [4] page 32

To take into account each country's specificities, two alternative linear approximation methods have been adopted in this edition of the adequacy assessment [4], namely (a) the linear rescaling and (b) the stretch rescaling. The linear rescaling method scales linearly the load based on the simulated daily energy change, for a daily temperature change from normal temperature, according to the daily energy sensitivity (in MWh/°C). The stretch rescaling method, uses different load sensitivities (in MW/°C) for daily maxima and minima to scale the daily load, for a daily temperature change from normal temperature, where the scaling factor for the minimum load could be different from the scaling factor for the maximum load. Both methods calculate for each hour the increase (or decrease) of load ΔP according to the daily temperature change from normal temperature. The two linear methods are described in detail in page 33 of [4]. Currently, ENTSO-E is evaluating the application of cubic polynomial approximation (see page 34 of [4]) for selected countries, which could be used in forthcoming adequacy assessment reports.

As mentioned in [4] *"Load forecasts provided for MAF 2016 for the case of Greece are obtained from the 'Base Case' development scenario of the latest national TYNDP"* (page 79). Figure 4 shows the data of the load for year 2020 used for Greece in MAF 2016, as provided by ADMIE. According to this profile, there is a peak demand of approx. 10.5 GW in summer 2020 (SP) and a peak demand of slightly more than 9 GW (WP) in winter 2020.

Figure 4. Normalized load - 2020 Expected Progress: results for Greece Summer Peak (SP) and Winter Peak (WP) – date and MW



Source: From [4], excel sheet available online https://www.ENTSO-E.eu/outlooks/maf/Pages/default.aspx

No explicit representation of Demand Side Management (DSM) or Demand Side Response (DSR) measures are included in the modelling of demand in this edition of the assessment. *"Last resort emergency capabilities available to TSOs"* are included in the analysis given the data collected from TSOs on their potential for load reduction capabilities. Section 0 summarises the future methodological improvements announced by ENTSO-E on the next editions of MAF, which include also accurate representation of DSM and DSR.

2.4 Supply

The model of supply includes parameters and projections relative to the generation fleet of renewable and conventional plants, electricity storage technologies and cross-border capacity. The main parameters are summarised in Table 7.

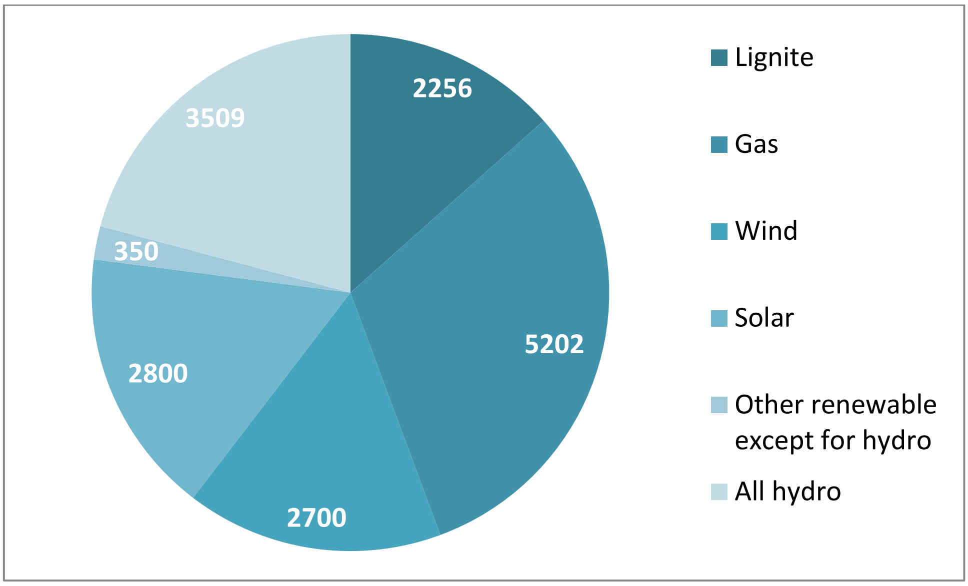
Table 7. The model of supply (parameters).

Model of supply		Indicators
Generation	- The model includes projections on the future installed capacity and the availability of the generation units. - Optimised plant maintenance schedule - Forced outages simulated randomly in MC scenarios	—Net generation capacities —Availability factors, forced and planned outages[9] —Hydro generation profiles[10] accounting for country specificities modelled in sub-regions
Renewables	The model of supply includes information on current and future installed capacities and locations. Consideration of RES as available generation. Another aspect is to preserve the spatio-temporal correlation structure between demand, wind, solar and non-dispatchable hydro generation.	—Share of renewables in the generation mix —Net generating capacity by technology and by country
Demand side response	Not included in the present assessment.	
Pump-hydro Storage	This technology is included in the modelling of hydroelectric power plants	—Energy storage capacity (MWh) —Peak power it can provide (MW)[11]

Net Generating Capacity (NGC) is defined as MW of installed capacities per country and per scenario. Figure 5 reports the NGC projections for Greece for 2020 that are used as input parameters in the adequacy assessment.

[9] These values have not been published in the MAF2016 excel file nor in the report.
[10] For a detailed explanation of the hydro modelling see MAF 2016 [4], p. 49-53.
[11] These values are not provided in the MAF report or excel file.

Figure 5. Net Generation Capacity (MW). Expected Progress for year 2020. Detail for Greece.



Note: According to the data, no MW of net installed capacity of nuclear, hard coal, oil and other non-renewable sources is foreseen in Greece in 2020.

Source: From [4], excel sheet available online https://www.ENTSO-E.eu/outlooks/maf/Pages/default.aspx

Only projects that are under construction, or have already contracted, are assumed in the construction of the scenarios for 2020 and 2025, even though several new plants have obtained generation licenses. It appears that the main factor in Net Generating Capacity evolution for the period 2016 – 2025 will be the decommissioning of old lignite-fired units and the increase of RES capacity. Confirmed projects include an 810 MW CCGT plant in Megalopoli (which is expected to be operational partially in 2016 and fully in 2019) and a new lignite-fired plant of 620 MW in Ptolemaida (expected in 2022), as well as a couple of new hydro storage plants ([4] page 79).

2.5 Scenarios and sensitivity analysis

A best estimate of the following parameters is made to represent the power system for the two future scenarios (2020 and 2025):

- Net generating capacities which include installed capacity by technology and country and differentiated by expected progress for 2020 and 2025;
- Generation basic model which includes assumptions on the efficiency of thermal plants (efficiency range in NCV terms) per technology, which is the same for both scenarios;
- Planned and forced outages for generators, represented in terms of unavailability factors, although they are not publicly available;
- Hydro generation profiles that take into account the hydrological conditions (dry, wet, normal with the associated likelihood/frequency of its occurrence expressed in terms of probability). It is worth mentioning that Greece has not been included in the two regions examined by ENTSO-E. It is unclear what assumptions were used regarding the probabilities of wet/average/dry years and how these were tagged to historical years. Moreover 2008, which is referred to as a normal year for IT & CH (see Figure 22 of [4]) was one of the driest years for the Greek System (see Figure 4.1 of [5]).
- Fuel and CO_2 price assumptions for each scenario ;
- Adequacy reference transfer capacities, including simultaneous importable / exportable capacities per scenario 2020 and 2025;

- Power demand, which is given in terms of normalized load - Expected Progress for 2020 and 2025 by country and under normal climate condition;
- Forced outages for generators and high-voltage direct current (HVDC) lines – the latter under Sensitivity II scenario only - represented in terms of unavailability factors.

The sensitivity analysis around different assumptions on reserves and HVDC interconnections are made corresponding to three sensitivity cases:

1. *Base case*: Day-ahead adequacy. Operational reserves do not contribute to adequacy;
2. *Sensitivity case I*: Day-ahead adequacy + operational reserves contributing to adequacy; 'real time' adequacy;
3. *Sensitivity case II*: Sensitivity Case I + HVDC forced outages.

2.6 Consideration of reserves

In the simulations considered in MAF 2016, a certain capacity from the provided Net Generation Capacity (NGC) is considered to cover the reserve requirements of each TSO. In the Base Case simulations, this capacity is considered as not contributing to adequacy (D-1 situation), while in the Sensitivity simulations, this capacity is assumed to contribute to adequacy (real-time situation). Common to all the tools used, perfect foresight and forecast in Day-Ahead markets (error in forecast load and renewable are not simulated) is considered.

No information is provided in [4] as to the value of reserve requirements considered in the simulations or how the reserves are estimated.

2.7 Interconnectors

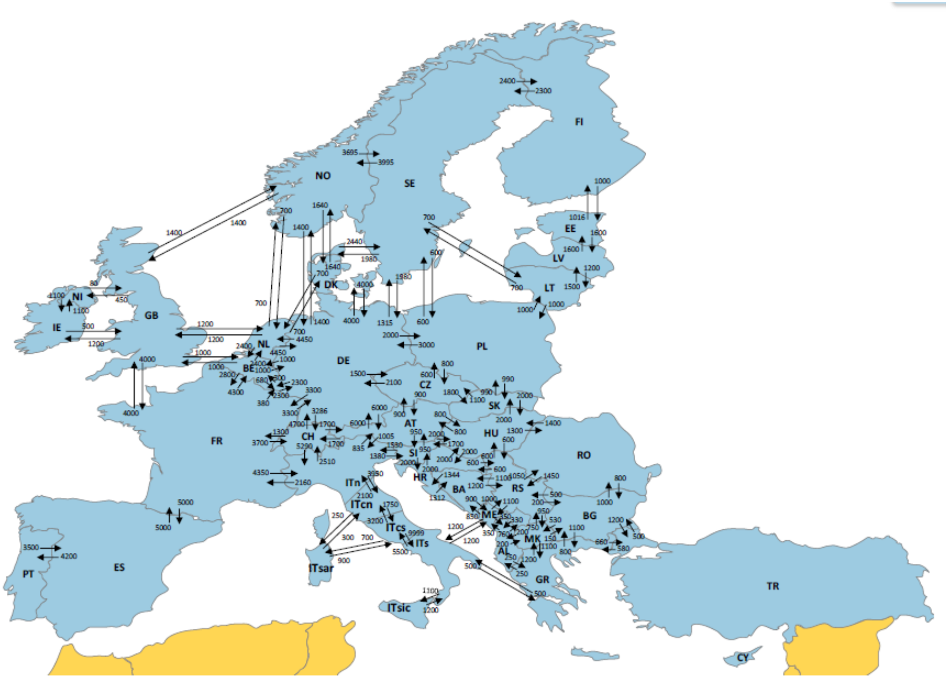
Within the MAF 2016 the Adequacy Reference Transfer Capacities values for the representation of cross-borders capacity have been setup in a way to ensure consistency with the TYNDP 2016 reference capacities. Conservative assumptions, due to uncertainty in the commissioning dates of cross-border transmission capacity projects, regarding the evolution of transmission capacity between 2020 and 2025 were used.

The main parameters included in the modelling are:

- Adequacy reference transfer capacities values (Figure 6);
- Simultaneous importable / exportable capacities;
- Projects with the positive impact on the transfer capacities (Regional Investment Plans of TYNDP 2016);
- All four simulation tools consider predefined exchanges with the borders between ENTSO-E and non-ENTSO-E countries as input to the model in the form of hourly commercial exchanges estimated by TSOs of ENTSO-E countries.

An unavailability rate for each HVDC interconnector of 6% was decided as benchmark value. ENTSO-E acknowledges that *"for some interconnectors the rate has been higher".* It is worth mentioning that the IT-GR interconnector has exhibited in the past significantly higher outage rates that the 6% universally applied. From [14] the availability of the IT-GR interconnector was 45.99% in 2014 and 72.91% in 2015. Furthermore, during the entire recent scarcity period (Dec. 2016 and Jan. 2017) the interconnection was unavailable.

Figure 6. Adequacy reference transfer capacities values



Source: [4] page 47

2.8 Adequacy indicators

The risk analysis for the assessment of adequacy issue is based on the evaluation of the *"existence of sufficient resources to meet the customer demand and the operating requirements of the power system"* [4]. The indices for adequacy studies calculated in the MAF 2016 – falling into the category of "hierarchical level I"[12] - assess the adequacy of the total generation system including the effect of transmission constraints as Net Transfer Capacities (NTCs).

The indicators traditionally used for the adequacy assessment are three: Energy Not Supplied (ENS), Loss Of Load Expectation (LOLE) and Loss Of Load Probability (LOLP) as described below, although the present edition of MAF computes only ENS and LOLE:

- Energy Not Supplied or Unserved Energy (ENS) [MWh/y] is the energy not supplied by the generating system due to the demand exceeding the available generating and import capacity.
- Loss of Load Expectation (h/y) LOLE is the number of hours in a given period (year) in a given period (year) in which the available generation plus import cannot cover the load in an area or region.
- Loss of Load Probability (%) LOLP is the probability that the load will exceed the available generation at a given time.

To obtain a satisfactory analysis of the influence of different parameters on the results (e.g. input data, outages and modelling with the use of different tools), various sensitivity analyses were conducted (for more detailed on the sensitivity analysis see paragraph 2.5). Results from the four different tools for LOLE and ENS and with respect to 3 cases (base case, and two sensitivity cases) are rendered as mean, 50th and 95th percentile of ENS (MWh) and of LOLE (hours) for each country and each scenario (2020 and 2025).

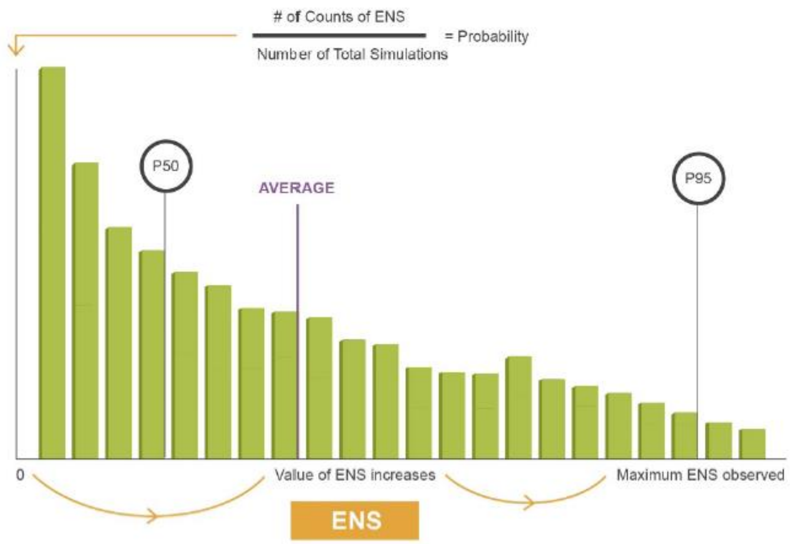
[12] For details on the hierarchical level II and III used for adequacy evaluation, see page 29 of MAF 2016.

The convergence check of the modelling results from the four tools has been conducted by the analysis of error between the expected value and its average (see section 3.1.2 page 30 of [4]).

2.9 Results

For each hour in a Monte Carlo sample (as described in 2.2.3) the ENS values can be zero which results in no adequacy problem or different to zero which signifies that adequacy problem was found.

Figure 7. Example of probability distribution of adequacy problem events (ENS)



Source: [4] page 11

Some statistical elaborations of the modelling results help in finding the relevant information for the purpose of the assessment. In MAF 2016 the mean value of ENS, the median (P50) - which renders a value of $\overline{ENS}$ for which the probability of ENS being > $\overline{ENS}$ is equal to the probability of ENS being < $\overline{ENS}-$, and the 95 percentile (P95), which renders a value of ENS_{P95} for which 95% of values found are lower or equal to this value and the remaining 5% are higher, are calculated (Figure 7). This last case corresponds to the so called 1-in-20 years case which represents the "low probability – high impact" case. The median or P50 value is important because is robust to outliers or extreme values, which is not the same for the average or expected value. In the same way the results for LOLE for each simulation run are expressed.

Results of the simulations differ strongly across country, sensitivity case and for each tool used. In particular, Table 8 and Table 9 (and also Figure 8 and Figure 9) show the results of LOLE and ENS for those countries for which different results from the four tools are identified, at least with respect to one scenario. The Tables report the minimum and maximum value of LOLE and ENS among the four tools, for the year 2020. This information shows the magnitude of the difference in the results among the tools[13], although a statistical check of the significance of the difference was not performed. It can be seen that for Greece the three tools result in no adequacy issues for 2020, whereas the forth tool provides a LOLE of 4.7 hrs/year.

[13] For a comprehensive representation of the generation adequacy results of MAF 2016 see chapter 5 of the report [4].

Table 8. Results of LOLE. Minimum and maximum LOLE values of the 4 tools. Details by sensitivity case for year 2020

	BASE CASE		SENSITIVITY (1)		SENSITIVITY (2)	
	MIN LOLE	MAX LOLE	MIN LOLE	MAX LOLE	MIN LOLE	MAX LOLE
BG	0	3.5	0	0.2	0	0.2
CY	0	14.5	0	16.8	0	16.9
FI	0.1	13.6	0	0.1	0.6	1.3
FR	0.7	4.7	0.1	2.2	0.1	2.2
GB	3.6	11	3.2	5.4	3.6	7
GR	**0**	**4.7**	**0**	**0**	**0**	**0**
IE	0.6	1.7	0.1	0.4	0.1	0.5
IT	0.8	7	0	0.6	0	0.6
NI	0.6	2.3	0.1	0.4	0.1	0.5
PL	0	3.4	0	1.1	0	1.3

Source: Table 2 page 15 [4]

Figure 8. Differences between min and max values for LOLE (Table 8) by sensitivity case

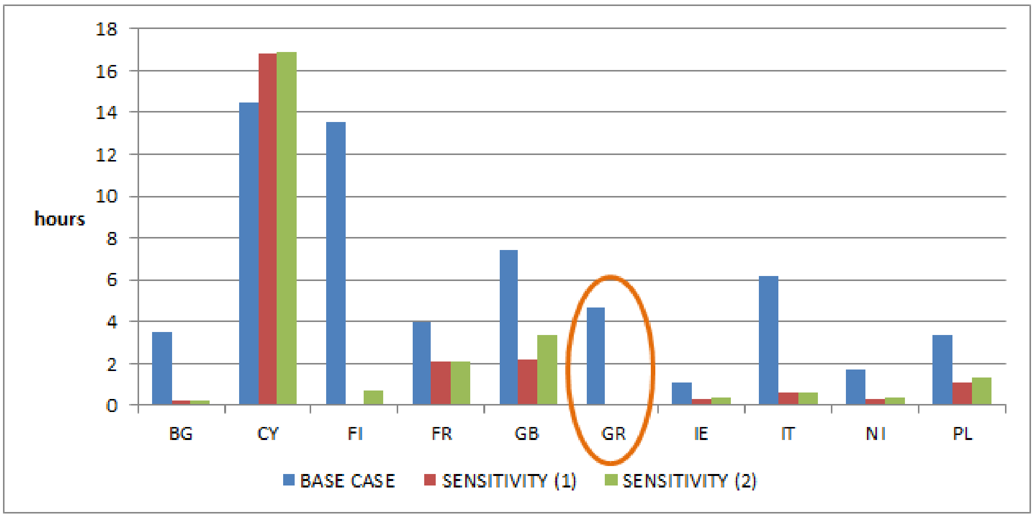
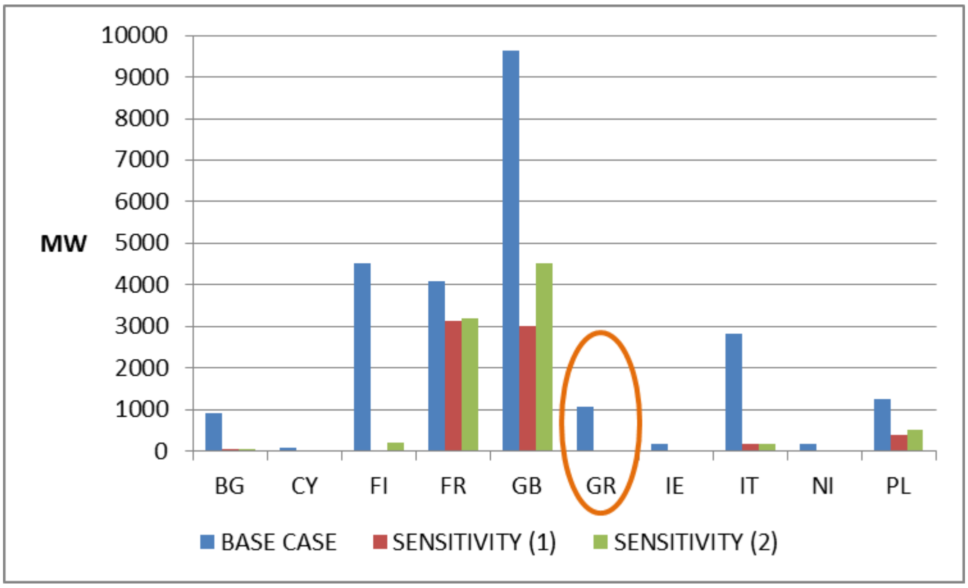


Table 9. Results of ENS. Minimum and maximum values of average results of ENS of the 4 tools. Details by sensitivity case for year 2020 (MAF 2016, Table 2)

	BASE CASE		SENSITIVITY (1)		SENSITIVITY (2)	
	MIN ENS	MAX ENS	MIN ENS	MAX ENS	MIN ENS	MAX ENS
BG	0	905	0	53	1	51
CY	0	96	0	27	0	27
FI	23	4540	1	29	153	369
FR	912	4991	130	3251	85	3293
GB	5440	15061	4877	7877	5534	10043
GR	**0**	**1081**	**0**	**5**	**0**	**5**
IE	55	244	15	37	33	48
IT	94	2922	0	165	2	170
NI	17	194	10	17	11	25
PL	0	1260	0	404	0	514

Source: ([4], Table 2 page 15)

Figure 9. Differences between MIN and MAX values for ENS (Table 9) by sensitivity case



GRARE, one of the 4 tools used for the adequacy assessment, records the highest levels of LOLE and ENS for many of the countries, including Greece (see details in Table 10). With respect to the other sensitivity cases (1 and 2) GRARE doesn't seem to behave with the same trend.

In general, according to ENTSO-E *"the higher values of ENS/LOLE reported by GRARE are related to the fact that this tool, differently from the other, does not employ a different pumping/generating regime for different Forced Outage Rate patterns. Hydro optimization assumes to have only the knowledge of FOR of thermal units applied as a reduction of production capability and not depending on Monte Carlo sampling"* ([4] page 64).

Finally, ANTARES and BID generally report lower values for ENS/LOLE – as, for example, in case of Greece (Table 10). This can be attributed to *"the fact that a different hydro optimization is considered in each MC year considering perfect forecast knowledge of forced outages (FOR) of thermal units. This perfect foresight information is provided to the hydro optimization so hydro power optimizes its schedule to minimize adequacy problems"* ([4] page 64).

Table 10. Results of adequacy assessment of Greece. Average and P95 for LOLE and ENS. Detail for the Base Case year 2020 for the four tools used by ENTSO-E

TOOL	**ANTARES**		**BID**		**PLEXOS**		**GRARE**	
RESULT	*average*	*P95*	*average*	*P95*	*average*	*P95*	*average*	*P95*
ENS	448	2572	0	0	11	0	1081	3276
LOLE	2	7	0.002	0.015	0	0	5	20

Source: Table 8 page 58 (for results of ENS) and table 9 page 61 (for results of LOLE) [4]

2.10 Remarks

ENTSO-E has announced a number of improvements foreseen in the next editions of the MAF. They include:

Extension of the PECD

Improvements of the Pan-European Climate Database (PECD 2.0) which will cover a number of additional countries and climate years, available from existing global climate reanalysis models of a higher temporal resolution (beginning from years 1982 to 2015). It will also cover more representative samples of the climatic variations and, in particular, higher statistical representativeness of extreme climate and calendar events such as cold spell, heat waves, extreme low wind conditions, solar eclipses, etc.

Revision of the representation of generation and transmission

- Revision of thermal portfolio categories and data details and assumptions therein;
- Revision of cross-border interconnector assumptions to account for seasonality and operational constrains;
- Revision of the data on anticipated decommissioning of power plants;
- Use of flow-based market methods.

Improvements in the modelling of operation reserves

In addition to the current assumptions regarding the modelling of operational reserves, further improvements might be considered in future reports, in line with the implementation of the pertinent Network Codes, and further considerations regarding the impact of sharing operational reserves on a real time basis, across synchronously-connected countries in ENTSO-E.

Inclusion of a model for DSM

- Load management, modelled as extra generation unit at the end of the merit order;
- Load management, taken into account in the load profile as load reduction (ex-ante);
- Peak shaving, through the collection of data for the potential of peak shaving for all time frames (2020/2025) and take this into account in the load profile (ex-ante);
- Modelling of peak shaving by some sort of ‘pump storage’;
- Possible extra development to model demand price elasticity.

3 ADMIE generation adequacy methodology review

3.1 Introduction

The objective of this chapter is to present the main characteristics of the generation adequacy methodology of ADMIE as described in [5], and to provide remarks. As mentioned in the previous Chapter, the review of the methodology follows the same elements as in [10], thus, setting a comprehensive framework. The elements used to review the generation adequacy methodology of ADMIE are the:

- type of methodology implemented;
- model of demand (also the consideration of demand side response);
- model of supply (including the consideration of RES production and hydro-generation);
- scenarios used (including sensitivity analysis);
- consideration of reserves;
- consideration of cross-border capacity;
- indicators and criteria used; and
- presentation of results

It should be noted that the Greek electricity system comprises of the interconnected system (mainland and interconnected islands) and the non-interconnected (islands) system. The latter consists of 32 autonomous power systems. The generation adequacy study of ADMIE focuses on the interconnected transmission electricity system, which is under the responsibility of ADMIE, taking into account the island systems that are planned to be connected in the future to the mainland transmission system. The latest generation adequacy study by ADMIE is performed with a time horizon of 7 years (2017-2023), and a periodicity of one year.

Furthermore, the aforementioned study of ADMIE references two other documents, the Ten Year National Development Plan 2017-2026 [15] and the, Handbook of the Capacity Assurance Mechanism v.3 (*Εγχειρίδιο Μηχανισμού Διασφάλισης Επαρκούς Ισχύος Έκδοση 3*) [16]. Both documents have been approved by RAE, and the former document is referenced regarding the evolution of the demand estimates and the latter (Appendix V) provides more information regarding the software used (PROSIM) for the probabilistic analysis. The relevant sections of both documents were taken into account for this review of ADMIE's generation adequacy methodology.

It is noted that all Tables and Figures shown in the following sub-Sections are non-official translations conducted by the authors of this report from the Greek original.

3.2 Methodology

The adequacy of the generation portfolio is determined by an analytical probabilistic model (convolution techniques). For every scenario, and for every year considered, the annual probabilistic indicators LOLE (Loss of Load Expectation) and EUE (Expected Unserved Energy) are calculated.

For the probabilistic analysis of the generating system, the PROSIM software was used, which was developed by the Power Systems Laboratory of the National Technical University of Athens (NTUA). The model takes into account the availability of generating units and their maintenance requirements. Each year of the considered period is examined with the granularity of one week, to allow for the modelling of the maintenance periods of the production units. For each scenario considered, the stochastic nature of forced outages of generating units is taken into account using the Equivalent Demand

Forced Outage Rate ($EFOR_D$) of the units. $EFOR_D$ is the probability that a generator will fail completely, or in part, at the time that it is needed. It allows the measurement of the probability of a forced event during demand times. $EFOR_D$ is calculated according to the following equation

$$\mathrm{EFOR_D} = \frac{\mathrm{f_f \times FOH + f_p \times EFDH}}{\mathrm{SH + f_f \times FOH}} \qquad (2)$$

where

SH – Service Hours, which are the hours the system needs the unit

FOH – Full Forced Outage Hours

EFDH – Equivalent Derated Hours

f_f and f_p – are the full factor and partial factor, which are statistical values that approximate the number of full forced outage hours and equivalent derated hours, respectively, during demand hours. More information on the method used by ADMIE to calculate the $EFOR_D$ can be found in the Hellenic Transmission Grid Code (article 185).

A further calculation is made which indicates the additional capacity required to return the system to the reliability standard, in steps of 50 MW. This effectively translates the gap between the LOLE projected for a given year and the reliability standard into an equivalent plant capacity (in MW). If the system is in surplus, this value indicates how much plant can be removed from the system without breaching the LOLE standard. Conversely, if the system is in breach of the LOLE standard, the calculation indicates how much capacity should be added to the system to maintain security.

The model used is briefly described below. More information can be found in [16] and [17].

PROSIM is a production simulation model, which incorporates probabilistic techniques, and simulates the joint operation of a multi-area power system for a given time horizon and computes the energy balance, the cost of operation, emissions and the generation reliability (LOLP, un-served energy) on weekly, monthly, and annual basis, in meeting the forecasted load demand. The electro-production system of an area can consist of conventional thermal units, combined cycle units, pump-storage units, peak hydro units and non-dispatchable units (run-of-river units, wind parks, etc.). Import and export contracts with other power systems are taken into consideration. Annual maintenance scheduling is automatically determined and the maturing process of the forced outage rate is modelled. The model, when scheduling the units' maintenance program, uses an algorithm to levelize the reserve of the system. For the purposes of this study, the considered annual requirement for maintenance is four weeks for lignite plants, two weeks for the combined cycle units and one week for gas turbines. The model allows incorporation of timed step-wise unit rating as well as chronological changes in various solution options. Furthermore, the model provides the option of enforcing fuel limitations and constraints on CO_2 emissions.

On an annual basis the steps taken by the model are:

1. A composite chronological load series from the load series of each area is created.
2. The chronological load series to account for the operation of non-dispatchable units is modified.
3. The chronological load series to account for the import and export contracts is modified.
4. The chronological load series to account for the operation of the peak hydro units is modified.

5. From the post-hydro chronological load series, the load duration curve for each one of the 52 weekly periods is constructed.
6. The annual maintenance scheduling based on the levelized criterion, taking into consideration maintenance requirements of generating units is determined.
7. The operation of the power system is simulated and for each week the model:
    - determines the dispatch order of the blocks of the thermal units. Blocks are placed in a priority list in ascending order of their incremental cost or by adopted practices of the system;
    - dispatches the blocks of the thermal units according to the priority list. Probabilistic techniques are utilized in order to account for the forced outage rates of the units. Hours of operation, required fuel and emissions for each thermal unit are determined;
    - dispatches pump storage units for compulsory and economic operation;
    - determines the reliability of the system in terms of the Loss-of-Load Probability (LOLP);
    - determines the un-served energy;
    - determines cost of operation;

      stores the results of the weekly simulation in a file.;
    - checks whether fuel limitations of emission constraints (if these options are activated) are satisfied. If the constraints are not satisfied, the previous step is repeated;
    - stores annual simulation results in a file.

The model assumes a known chronological load time series (8760 hourly loads). The load demand is represented by a load duration curve, which is then inverted and the time axis is normalized to 1. First the model simulates the operation of non-dispatchable units and the hydro units (using a peak shaving technique) resulting to a new annual chronological time series. The resulting load series has to be served by the thermal units of the system, taking into account the interconnections with neighbouring countries in case of emergency. Blocks of the thermal units are dispatched in ascending order of their incremental cost. According to [16], page 125, the dispatched hydro plants (excluding pumping units) are modelled as an equivalent unit whose operation is simulated by modifying the load duration curve (peak shaving) so that the total energy produced from the hydroelectric generators correspond to each hydro energy scenario under consideration.

3.3 Demand

The main drivers that affect the energy demand, as listed by ADMIE, are:

- The economic situation of the country indicated by the GDP.
- Changes in the consumption trends (air conditioning, electrification of transportation, usage of electrical computers etc.) due to the improvement of living standards, in general, and the improvement of the conditions of living of specific population groups (e.g. immigrants).
- The evolution of the energy sector and the electricity market in particular (electricity prices, competitiveness of the natural gas market etc.).
- Specific conditions (utilisation of Community structural funds etc.).
- The population growth.

- Implementation of policies regarding energy efficiency, environmental constraints etc.

The Greek generation adequacy assessment initially presents energy demand historical data for the period of 2000-2016. According to these data, during 2000-2008, the total energy demand, including the demand served by distributed generation, increased by an annual rate of 3.39%. After the start of the economic crisis, that is, from 2009 onwards, there was a decrease in the demand. It is noted though that from 2012 onwards, the increase of distributed generation units in the low and medium voltage resulted in a decrease of the local load in the distribution substations. This decrease is measured in the demand at the coupling points of the distribution system with the transmission system. In 2015, the distributed generation had reached 4.7 TWh, which corresponds to approximately 9.2% of the total energy demand for the year.

Regarding the annual demand peaks, they are registered during the summer season. From 2013, a peak appears also during winter, possibly due to the shift towards electrical heating by many residential consumers.

The model of demand is based on the national TYNDP 2017-2026 [15] which describes the projections of the evolution of the energy demand, including the demand which is served by the distributed generation. In the projections for 2017 onwards, the demand of the connected islands (Andros, Tinos, Siros, Paros, Naxos and Mykonos) is taken into account. On the other hand, the demand served by the mainland system towards the island of Crete during the period 2020-2023, after the completion of Phase I AC (AC connection of 250MW), is not included in the projections, but it is calculated through the simulations for each scenario separately.

Based on the historical data and the expected evolution of the GDP, which according to ADMIE is a decisive factor for the demand estimate, three scenarios regarding the evolution of the demand are constructed ("Reference", "High demand" and "Low demand"). As a reference point for all three scenarios, the total energy demand for the year 2015 is used, including distributed generation.

For the scenario of High Economic Growth, the generation adequacy assessment is based on the forecasts of the EU until 2017, whereas for the period 2018-2022 the respective documents from the IMF were used. For 2023-2026, due to the lack of data, GDP growth is assumed to be fixed. Based on the forecasted GDP, two more scenarios have been formed assuming Mild Economic Growth and Low Economic Growth (Table 11).

Table 11. Scenarios of GDP

	2017	2018	2019	2020	2021	2022-26
Scenario	%					
Low Economic Growth	2.0	2.0	1.0	0.7	0.7	0.5
Mild Economic Growth	2.7	2.6	1.9	1.6	1.2	1.0
High Economic Growth	2.7	3.1	2.8	2.4	1.7	1.5

Source: Table 14 of [15]

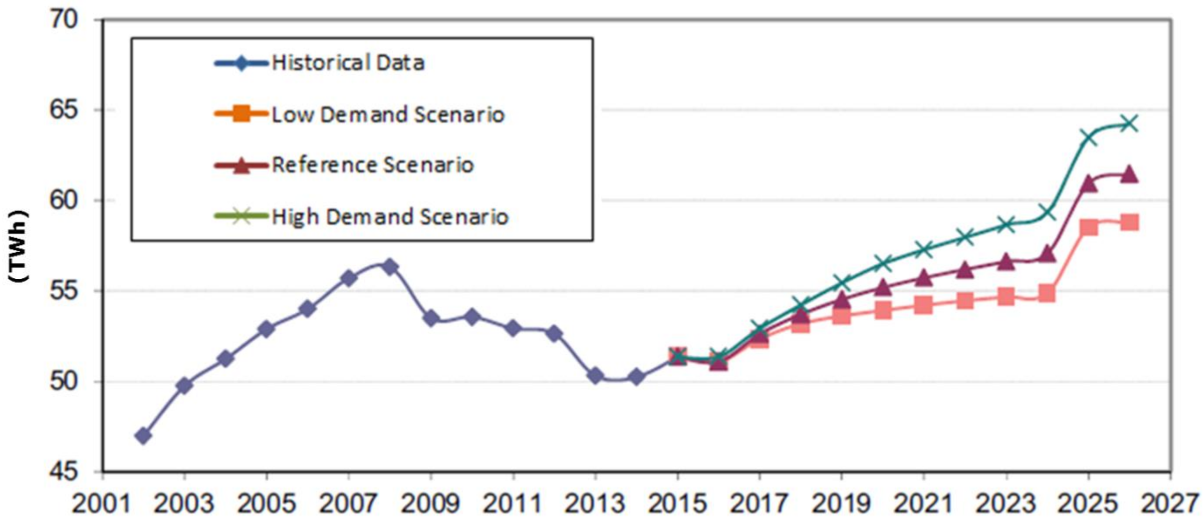
Table 12. Scenarios for the evolution of the total energy demand (2017-2023)

Scenario	Low Demand	Reference	High Demand
Year		(GWh)	
2017	52335	52620	52915
2018	53170	53690	54220
2019	53600	54510	55430
2020	53900	55180	56500
2021	54210	55720	57260
2022	54430	56165	57950
2023	54650	56620	58650

Source: Table 2.3 of [5]

According to the Reference scenario, the total demand after 2017 increases with an average annual rate of 1.08%, the rates for the High Demand and Low Demand scenarios are 1.55% and 0.61% respectively (Figure 10).

Figure 10 Evolution of total energy demand



Source: Figure 2.6 of [5]

The forecast of the peak load has more uncertainties than the projection of the demand. This is due to the dependency of the peak demand on the weather conditions, especially the temperature and the duration of high temperatures. The integration of distributed generation makes the projection of the peak even more difficult. Furthermore, it is not straightforward to assess the impact of the economic crisis on the consumers' behaviour during peak hours in the summer, especially during a heat wave.

Based on the above, the generation adequacy assessment of ADMIE presents three scenarios for the estimation of the energy peaks, "Reference", "High" and "Low" (Table 13). The load which will be served by distributed generation is also considered. ADMIE emphasises in the analysis that 2400 MW of PV are currently connected in the low and medium voltage in the mainland. Thus, the power flow in the transmission system during the summer of 2016 and onwards will be 1500-1800 MW less than anticipated due to the solar generation. Peaks during winter have been also considered in the scenarios based on the observation on the historical data where peaks have been noticed during winter evenings (Table 14).

Table 13. Forecast of annual peak load (peak during summer excluding distributed generation)

Scenario	Low	Reference	High
Year	(MW)		
2017	9875	9930	9985
2018	10030	10130	10230
2019	10110	10285	10460
2020	10170	10410	10660
2021	10230	10515	10800
2022	10270	10600	10935
2023	10310	10680	11070

Source: Table 3.5 of [5]

Table 14. Forecast of peak load (during winter)

Scenario	Low	Reference	High
Year	(MW)		
2017	9480	9530	9590
2018	9630	9725	9820
2019	9700	9870	10040
2020	9760	10000	10230
2021	9820	10090	10370
2022	9860	10180	10500
2023	9900	10250	10630

Source: Table 3.6 of [5]

3.4 Supply

According to the generation adequacy assessment of ADMIE, and within the framework of the liberation of the energy market, the evolution of the power generation system presents many uncertainties. The commissioning of new units is no longer centrally planned under the objective of future system adequacy. Instead, it is planned by independent generators under the objective of economic viability. Even planned investments present some uncertainties due to the unpredictable difficulties which can be faced during the licencing process and/or the construction phase.

A basic scenario is used for the evolution of the power generation system during the period 2017-2023 (Table 15).

Table 15. Scenario for the evolution of the power generation system

New installations				Decommissioning			
Unit	Capacity (MW)	Fuel	Year	Unit	Capacity (MW)	Fuel	Year
Megalopoli 5	400	Natural Gas	2016	Amuntaio 1	273	Lignite	Spring 2020
Megalopoli 5	811	Natural Gas	2019	Amuntaio 2	273	Lignite	Spring 2020
Ptolemaida 5	620	Lignite	2022	Kardia 1	275	Lignite	Spring 2020
Ilarionas	153	Hydro	2016	Kardia 2	275	Lignite	Spring 2020
Mesochora	160	Hydro	2017	Kardia 3	280	Lignite	Spring 2020
Metsobitiko	29	Hydro	2022	Kardia 4	280	Lignite	Spring 2020
Aulaki (Terna)	60	Hydro	2022	Megalopoli 3	255	Lignite	End 2022
				Megalopoli 4	256	Lignite	End 2028

Source: Table 4.10 of [5]

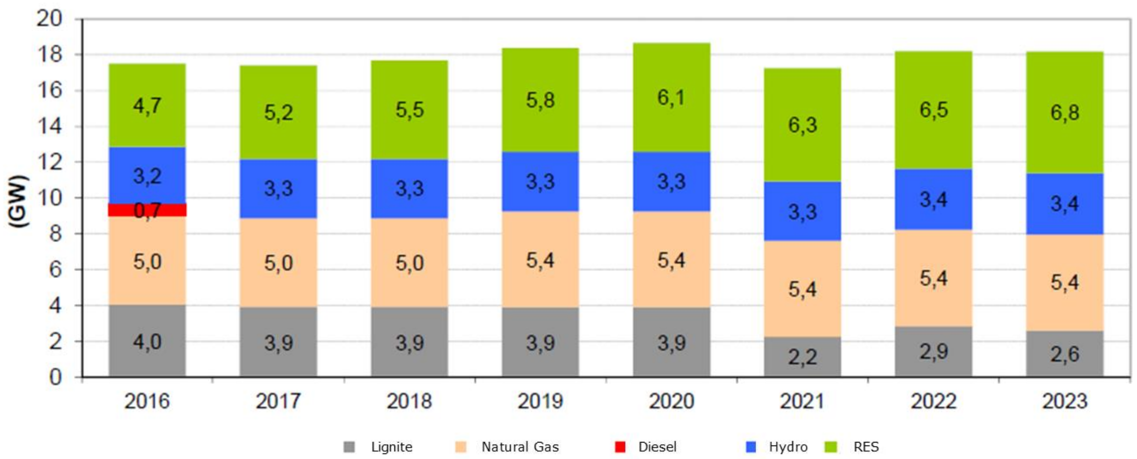
The above basic scenario is examined in combination with the integration of renewables scenario (Table 16), forming the reference scenario of the generation mix for the period 2017-2023 (Figure 11).

Table 16. Renewables integration scenario (MW)

	2016	2017	2018	2019
Wind	1857	2175	2350	2525
PV	2444	2564	2640	2720
Small Hydro	223	245	248	250
Biomass/Biogas	52	105	135	170
CHP	100	125	125	125
TOTAL	4676	5214	5498	5790
	2020	2021	2022	2023
Wind	2700	2850	3000	3150
PV	2800	2880	2960	3040
Small Hydro	252	254	256	258
Biomass/Biogas	200	200	200	200
CHP	125	125	125	125
TOTAL	6077	6309	6541	6773

Source: Table 4.9 of [5]

Figure 11. Evolution of the Generation Mix – Reference Scenario



Source: Figure 4.4 of [5]

The stochastic methodology for the adequacy analysis has been applied in the reference scenario of the generation capacity. A basic parameter for the calculations of the reliability indices is the availability of the thermal units, which is expressed with the index EFORD (Equivalent Demand Forced Outage Rate) which describes unplanned outages. For the purposes of the analysis, the values that have been published in the ADMIE Table of Available Capacity for the Year October 2015-September 2016 were used. For the new units, typical values of the index were assumed.

The scheduled maintenance of the units is established through the PROSIM model with the usage of an algorithm which uses levering of the reserve. Thus, for the scope of the analysis, the annual maintenance is 4 weeks for the lignite units, 2 weeks for the CCGTs, and 1 week for the gas turbines.

The hourly operation of all RES (excluding PV) for each year is formed taking into consideration the average monthly loading of the last five years and the capacity that has been assumed for each scenario of RES integration. For PV, the hourly generation series for each year is formed by amending the respective series from the year 2014 so that it corresponds to the capacity of Table 16. The RES generation series are subtracted from the respective series of the total demand.

The operation of the big hydro units (excluding the pump hydro) is simulated with the appropriate amendment of the load curve (peak shaving) in such a way that the generated power corresponds to the power of the scenario under consideration. Three scenarios are examined based on the hydrological conditions (dry, medium and wet year). The scenarios have been formed based on the statistical analysis of historical data and correspond in annual production of 2200 GWh, 4200 GWh and 5700 GWh, while the maximum peak shaved due to the operation of the hydro units was assumed to be 2200 MW, 2400 MW, and 2700 MW respectively. For each scenario the extra hydrological generation from the operation of the pumping units is assumed and simulated by the PROSIM model.

3.5 Scenarios

For the scope of the analysis there are several scenarios taken into consideration. For demand, as aforementioned, there are three scenarios: Reference, Low demand, and High Demand. For each one, the demand served by distributed generation is also included.

For the total annual peak load, that includes system losses and the load that is expected to be served locally by the distributed generation, three scenarios are considered:

Reference, High and Low. These scenarios refer to the mid-day summer peak. However, due to the installed distributed generation (mainly PV), the mid-day summer peak loads, as seen by the transmission system, have been reducing in recent years and the evening peak loads have become more important for the development of the network. In addition, since 2013 the peak evening load has been observed during winter. Thus a forecasted peak load during winter has also been considered with three scenarios as well: Mild, Reference and Extreme.

For the supply and especially for the thermal units, there is only one scenario taken into account, the reference scenario based on the planned commissioning and decommissioning of thermal units.

For production from RES, there is a basic scenario referring to the forecasted installed capacity for technology and for each year under consideration.

For the hydro units, there are three scenarios formed based on the hydrological conditions: Dry, Medium and Wet year.

For the interconnections, there are two scenarios considered: with and without interconnectors. The contribution of the interconnectors has been assumed as the equivalent of a thermal unit of 500MW base load with 95% of availability.

3.6 Consideration of reserves

When considering the generation adequacy of the system, the available generation shall cover the demand and the reserve needs for the secure operation of the system. Avoiding reserve needs estimation can lead to an underestimation of the future flexibility needs of the system.

In [16] it is mentioned that when modelling the hydro units the necessary operational secondary reserves are taken into account. However, in generation adequacy study of ADMIE, no other information is provided on whether or not, and if yes how, the requirement for reserves is taken into account.

3.7 Interconnectors

The parallel operation of the Greek power system with the Central European one is realised through the interconnectors, basically 400kV, with the systems of Albania, Bulgaria, and FYROM. Furthermore, the Greek system is connected with Italy through a 400kV HVDC submarine cable. Since September 2010, the Greek power system is also connected with the Turkish system which is further connected with the Bulgarian one.

In Table 17 the cross-border flows are shown. From the data it is clear that Greece is a country that mainly imports energy.

Table 17. Utilisation of interconnections in the last ten years

	Imports (GWh)	Export (GWh)	Balance (GWh)
2006	6139.46	1937.08	4202.38
2007	6411.50	2057.31	4354.19
2008	7574.76	1960.79	5613.97
2009	7600.77	3233.07	4367.70

2010	8517.36	2811.23	5706.13
2011	7179.77	3947.44	3232.33
2012	5954.04	4169.88	1784.17
2013	4703.54	2600.83	2102.70
2014	9461.66	642.25	8819.41
2015	11080.97	1472.22	9608.75

Source: Table 5.1 of [5]

The contribution of the interconnectors is taken into account in the generation adequacy assessment for the system adequacy and the system sufficiency (adequacy of the system with no interconnectors). For the scope of the analysis, the contribution of the interconnectors is regarded as the equivalent of a thermal unit of 500MW base load with 95% availability. This corresponds to import energy of 4161 GWh. It should be noted that this assumption is quite conservative for the contribution of the interconnectors, but it's adopted under the consideration that the results err on the safe side.

3.8 Indicators

The adequacy of the system is expressed with two reliability indices: Loss of Load Expectation (LOLE) and the Expected Unserved Energy (EUE).

- LOLE, in hours per year, expresses the expected hours of the year in which there will not be enough available generation capacity to supply demand, regardless of the deficit for each hour.
- EUE, on an annual basis, expresses the GWh that the supply system is expected to be unable to serve.

The adequacy of the supply system should be evaluated with both indicators. EUE defines directly the capability of the system to be adequate, while the LOLE consists of an indication of the percentage of the hours during the year in which the demand will not be completely covered.

For the reliability standard 2.4 hrs/year was considered as satisfactory.

3.9 Results

In this Section, the results of the generation adequacy report of ADMIE are presented. More information can be found in Sections 6.4 and 6.5 of ADMIE's study [5].

3.9.1 Baseline scenario

With the probabilistic simulation model, as described above, the reliability indicators of the production system have been calculated considering both with and without the interconnections for the period 2017-2023, for the considered generation production scenario (Baseline Scenario), in conjunction with all demand development scenarios (reference, low, and high) and all hydro scenarios (dry, normal, and wet year).

Table 18 provides the results for the "Baseline Scenario" with interconnections. The coloured cells correspond to the cases where the calculated reliability indicator LOLE is higher than the adopted reliability standard of 2.4 hours/year. Figure 12 presents the LOLE for the baseline scenario with interconnections, for normal hydrological year.

The following conclusions for the cases with interconnections have been deduced by ADMIE:

- Until 2019, the LOLE reliability index values are significantly below the adopted reliability standard, for all considered scenarios, and therefore the power system is expected to adequately meet the demand.
- The simultaneous withdrawal of the lignite units of Kardia and Amyntaio in spring 2020 creates a risk for the adequacy of the system during the years 2020-2021 and, in particular, for the year 2021 where the reliability index (LOLE) increases significantly, surpassing the considered limit of 2.4 hours per year in the majority of scenarios. Especially under the combination of high demand and dry hydrological year, the operation of the power system can be described as inadequate, despite the contribution of interconnections (LOLE is estimated at 60,5 hrs/year).
- The expected commissioning of new Ptolemaida V unit in early 2022 seems to compensate for the loss of units of Kardia and Amyntaio, improving the reliability index (LOLE) which in most cases remains below the limit of 2.4 hours per year, except when considering the scenario with a combination of high demand and dry hydrological year, where the reliability standard is not fulfilled until after 2022.
- The decommissioning of the lignite unit Megalopoli 3 at the end of 2022 deteriorates further the calculated reliability indices for 2023.
- As expected, the hydrological conditions have a considerable effect on the reliability indices.

Table 19 provides the calculated surplus or additional generation to return the system to the reliability standard for the "Baseline Scenario" with interconnections. According to this table, the system will need a maximum additional generation of 1050 MW in 2021 when considering the scenario with a combination of high demand and dry hydrological year.

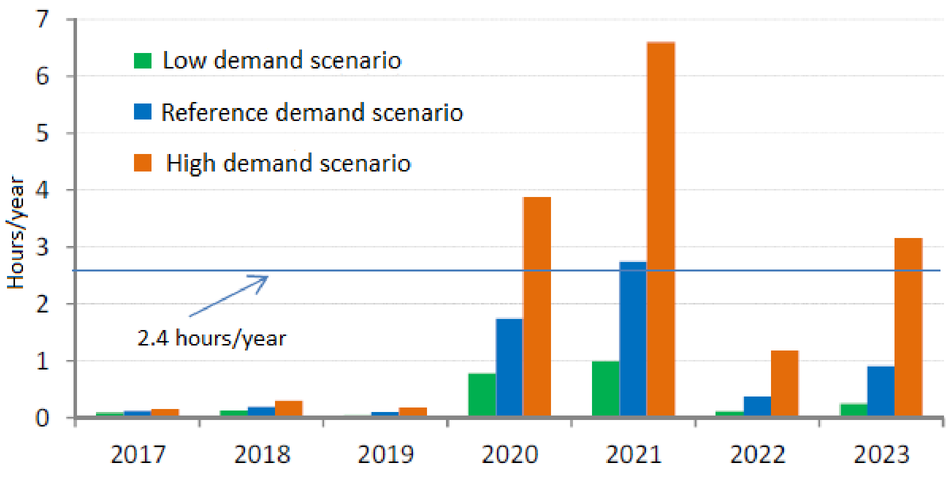
Table 18. Results for the "Baseline Scenario" with interconnections

	Dry hydrological year		Normal hydrological year		Wet hydrological year	
	LOLE (hrs/year)	EUE (GWh)	LOLE (hrs/year)	EUE (GWh)	LOLE (hrs/year)	EUE (GWh)
	Low Demand Scenario					
2017	0,316	0,049	0,093	0,014	0,045	0,006
2018	0,389	0,061	0,122	0,018	0,058	0,008
2019	0,167	0,027	0,047	0,007	0,024	0,004
2020	6,118	1,407	0,772	0,152	0,387	0,070
2021	14,029	3,171	0,991	0,190	0,454	0,081
2022	2,129	0,437	0,110	0,020	0,058	0,010
2023	4,279	0,915	0,243	0,045	0,134	0,023
	Reference Demand Scenario					
2017	0,402	0,063	0,113	0,017	0,056	0,008
2018	0,590	0,095	0,191	0,029	0,091	0,013
2019	0,346	0,059	0,098	0,016	0,048	0,007
2020	11,890	2,965	1,749	0,364	0,896	0,171
2021	28,459	6,980	2,746	0,562	1,265	0,244
2022	5,259	1,166	0,377	0,073	0,202	0,037
2023	11,305	2,628	0,909	0,183	0,502	0,095
	High Demand Scenario					
2017	0,488	0,077	0,149	0,022	0,072	0,010
2018	0,943	0,156	0,290	0,045	0,137	0,020
2019	0,638	0,113	0,180	0,030	0,100	0,016
2020	22,884	6,161	3,877	0,857	2,125	0,429
2021	60,459	16,310	6,599	1,454	3,234	0,667
2022	13,722	3,286	1,181	0,249	0,659	0,130
2023	31,483	8,051	3,151	0,699	1,806	0,375

Source: Table 6.3 of [5]

Table 20 provides the results for the "Baseline Scenario" without interconnections. The coloured cells correspond to the cases where the calculated LOLE is higher than the adopted reliability standard of 2.4 hours/year. From Table 20 it can be noted that these cases have increased compared to the results with interconnections.

Figure 12: LOLE indicator for baseline scenario with interconnections, for normal hydrological year.



Source: Figure 6.1 of [5]

Table 19. Surplus or additional generation to return the system to the reliability standard for the "Baseline Scenario" with interconnections

	Low demand scenario			Reference demand scenario			High demand scenario		
	Dry year	Normal year	Wet year	Dry year	Normal year	Wet year	Dry year	Normal year	Wet year
	(MW)								
2017	-450	-750	-900	-400	-700	-850	-350	-650	-800
2018	-400	-700	-850	-350	-600	-750	-250	-500	-650
2019	-650	-950	-1100	-450	-800	-950	-350	-650	-800
2020	300	-300	-450	500	-100	-250	750	150	0
2021	500	-250	-400	750	50	-150	1050	300	100
2022	0	-800	-1000	250	-500	-700	550	-200	-350
2023	150	-600	-800	450	-350	-400	850	100	-100

Source: Table 6.4 of [5]

Table 20. Results for the "Baseline Scenario" without interconnections

	Dry hydrological year		Normal hydrological year		Wet hydrological year	
	LOLE (hrs/year)	EUE (GWh)	LOLE (hrs/year)	EUE (GWh)	LOLE (hrs/year)	EUE (GWh)
	Low demand scenario					
2017	2,677	0,448	0,853	0,133	0,431	0,065
2018	3,215	0,547	1,098	0,175	0,551	0,084
2019	1,298	0,230	0,387	0,064	0,211	0,034
2020	29,467	7,807	4,547	0,980	2,591	0,509
2021	66,057	17,409	6,122	1,274	3,060	0,598
2022	11,507	2,640	0,756	0,146	0,429	0,078
2023	21,423	5,187	1,562	0,315	0,931	0,178
	Reference demand scenario					
2017	3,326	0,566	1,021	0,161	0,530	0,081
2018	4,683	0,821	1,660	0,271	0,842	0,132
2019	2,502	0,466	0,771	0,134	0,398	0,066
2020	65,213	20,480	9,381	2,141	5,470	1,144
2021	140,966	43,206	15,242	3,395	7,593	1,602
2022	25,412	6,357	2,339	0,486	1,344	0,266
2023	49,982	13,365	5,251	1,150	3,106	0,647
	High demand scenario					
2017	3,965	0,683	1,327	0,213	0,680	0,105
2018	7,174	1,296	2,436	0,410	1,224	0,196
2019	4,322	0,843	1,352	0,245	0,783	0,137
2020	123,431	46,964	18,654	4,483	11,559	2,545
2021	314,034	112,993	32,811	7,809	17,223	3,861
2022	60,260	16,609	6,512	1,477	3,912	0,841
2023	147,989	46,940	15,576	3,729	9,607	2,188

Source: Table 6.5 of [5]

The following conclusions for the cases without interconnections have been deduced by ADMIE:

- Even with autonomous operation, apart from the scenarios with a low hydrological year, the system is adequate up to 2019.
- During the years 2020-2021 the system relies heavily on imports for all cases.
- The expected commissioning of new Ptolemaida V unit in early 2022 improves the reliability index (LOLE) but the system is deemed inadequate for most of the cases.
- As with the cases with interconnections, the hydrological conditions have a considerable effect on the reliability indices.

Table 21. Surplus or additional generation to return the system to the reliability standard for the "Baseline Scenario" without interconnections

	Low demand scenario			Reference demand scenario			High demand scenario		
	Dry year	Normal year	Wet year	Dry year	Normal year	Wet year	Dry year	Normal year	Wet year
	(MW)								
2017	50	-250	-400	100	-200	-350	150	-150	-300
2018	100	-200	-350	150	-100	-250	250	0	-150
2019	-150	-450	-600	50	-300	-450	150	-150	-300
2020	800	200	50	1000	400	250	1250	600	450
2021	1050	250	100	1250	500	350	1550	750	600
2022	500	-300	-450	750	0	-150	1050	300	150
2023	700	-100	-350	1000	250	100	1300	550	400

Source: Table 6.6 of [5]

Table 21 provides the calculated surplus or additional generation to return the system to the reliability standard for the "Baseline Scenario" without interconnections. According to this table, the system will need a maximum additional generation of 1550 MW in 2021 when considering the scenario with a combination of high demand and dry hydrological year.

3.9.2 Alternative scenarios

In addition to the baseline scenario for the generation portfolio, ADMIE has examined the following alternative scenarios for the period 2017-2023, using the reference demand scenario, and assuming normal hydrological year,:

- The interconnection of Crete to the mainland is delayed beyond the study's horizon.
- Delays in the completion of the necessary transmission infrastructure in Peloponnese that will allow the unit Megalopoli V to operate up to maximum power.
- Delays in the commissioning of the unit Ptolemaida V.
- The withdrawal of two CCGT units.

The results are provided below, as presented in the study of ADMIE.

3.9.2.1 Crete interconnection

Crete is planned to be interconnected to the mainland transmission system within the considered period. According to ADMIE's report ([5], page 39), once the interconnection is complete, the annual demand that will need to be covered by the generating sources will increase by 1200-1350 GWh. ADMIE has calculated the reliability indices assuming that the interconnection will be delayed and will not be concluded within the studied period.

Table 22. Results for the "Baseline Scenario" without Crete interconnection, reference demand scenario and normal hydrological year

	With interconnections		Without interconnections	
	LOLE (hrs/year)	EUE (GWh)	LOLE (hrs/year)	EUE (GWh)
2017	0,113	0,017	1,021	0,161
2018	0,191	0,029	1,660	0,271
2019	0,098	0,016	0,771	0,134
2020	0,824	0,162	4,779	1,040
2021	1,177	0,229	7,116	1,506
2022	0,154	0,028	1,025	0,202
2023	0,387	0,074	2,392	0,498

Source: Table 6.7 of [5]

Table 22 provides the calculated reliability indices for the baseline scenario without the Crete interconnection for the reference demand scenario and normal hydrological year, with and without interconnections. Compared to Table 18 and Table 20, as expected, the reliability indices are improved.

3.9.2.2 Delays in the completion of the necessary transmission infrastructure in Peloponnese

The new gas-fired unit Megalopoli V was taken into account, in the baseline scenario, up to 2019 to be operating with reduced power (400 MW) and with full power (811 MW) after this period. However, the operation of the unit at full power depends on the on-time completion of the necessary transmission infrastructure in Peloponnese. If there are delays in the completion of the infrastructure then the unit will not be able to deliver full power.

Table 23. Results for the "Baseline Scenario" with the unit Megalopoli V operating with reduced power, reference demand scenario and normal hydrological year

	With interconnections		Without interconnections	
	LOLE (hrs/year)	EUE (GWh)	LOLE (hrs/year)	EUE (GWh)
2017	0,113	0,017	1,021	0,161
2018	0,191	0,029	1,660	0,271
2019	0,251	0,038	2,100	0,353
2020	5,011	1,024	29,536	6,726
2021	7,477	1,508	45,946	10,405
2022	1,037	0,198	6,506	1,336
2023	2,499	0,501	14,450	3,072

Source: Table 6.8 of [5]

ADMIE has calculated the reliability indices assuming that the transmission infrastructure will be delayed and will not be concluded within the studied period, thus the Megalopoli V unit will continue to operate with reduced power. Table 23 provides the calculated reliability indices for the baseline scenario with the unit operating with reduced power for the reference demand scenario and normal hydrological year, with and without interconnections. Compared to Table 18 and Table 20, as expected, the reliability indices are worsened considerably.

3.9.2.3 Delays in the commissioning of the unit Ptolemaida V

The commissioning of the new lignite plant Ptolemaida V (620 MW) is assumed in the baseline scenario to take place in 2022. ADMIE has also calculated the reliability indices assuming that, due to delays, the unit will not be commissioned within the studied period.

Table 24. Results for the "Baseline Scenario" without the unit Ptolemaida V, reference demand scenario and normal hydrological year

	With interconnections		Without interconnections	
	LOLE (hrs/year)	EUE (GWh)	LOLE (hrs/year)	EUE (GWh)
2017	0,113	0,017	1,021	0,161
2018	0,191	0,029	1,660	0,271
2019	0,098	0,016	0,771	0,134
2020	1,750	0,364	9,430	2,154
2021	2,745	0,562	15,245	3,397
2022	2,896	0,604	15,742	3,536
2023	6,486	1,430	32,963	7,830

Source: Table 6.9 of [5]

Table 24 provides the calculated reliability indices for the baseline scenario without the unit, for the reference demand scenario and normal hydrological year, with and without interconnections. Compared to Table 18 and Table 20, as expected, the reliability indices are worsened considerably.

3.9.2.4 Withdrawal of two CCGT units

ADMIE has also calculated the reliability indices assuming that, two CCGT units have withdrawn from the system and are not available.

Table 25. Results for the "Baseline Scenario" without two CCGT units, reference demand scenario and normal hydrological year

	With interconnections		Without interconnections	
	LOLE (hrs/year)	EUE (GWh)	LOLE (hrs/year)	EUE (GWh)
2017	5,760	1,048	47,894	10,419
2018	8,757	1,651	100,468	24,800
2019	3,684	0,738	20,667	4,635
2020	31,989	8,300	205,764	74,848
2021	50,101	12,818	329,487	115,089
2022	8,805	2,022	42,123	10,610
2023	18,292	4,404	101,533	28,860

Source: Table 6.10 of [5]

Table 25 provides the calculated reliability indices for the baseline scenario without the unit, for the reference demand scenario and normal hydrological year, with and without interconnections. Compared to Table 18 and Table 20, as expected, the reliability indices are worsened considerably.

3.10 Remarks

The generation adequacy assessment study of ADMIE is based on an analytical probabilistic model, calculating the annual probabilistic indicators LOLE and EUE for every scenario, and for every year considered. The probabilistic simulation software used (PROSIM), was developed by the Power Systems Laboratory of the National Technical University of Athens (NTUA).

As much of the input data used for the generation adequacy are not under the control of ADMIE, it is important to conduct a public consultation prior to its official release. This is a practice followed by many other TSOs.

In the previous sections, the basic elements of generation adequacy methodology of ADMIE were presented. Below we provide some remarks based on the available information:

- The demand and hydrological scenarios are not associated with a certain probability in the study. This leads to the conclusion that each scenario is of equal probabilistic weight, which might not be correct. Especially for hydrological conditions, the probabilities should be derived from historical data. The uncertainty of demand could be reasonably described by a normal distribution. Then the load characteristic can be modified to produce a load profile which includes uncertainty [7].
- Although it is mentioned that many drivers affect the energy demand, it appears that the estimates are based only on GDP projections. There is no analysis done to calculate the historic correlation between GDP and electricity demand. Furthermore, the temperature dependency of the load is not taken into account, which can be important, as was the case during the cold spell of January 2017. In addition, an analysis on how implementation of energy efficiency measures, as provisioned in the EU Energy Strategy and the National Energy Plan, demand side management, electric vehicles, and the electrification of other uses will impact future energy and peak demand, has not been carried out. It is worth mentioning that in the relevant literature, there new tendency is to forecast future consumption by sector (residential, tertiary, industrial, transport etc.), new uses of electricity and energy efficiency measures among others [10].
- Due to the employed methodology by ADMIE, the impact of different climatic conditions on the variable RES output are not taken into account at all. The variable RES (except PV) power output is based on average monthly utilisation coefficients of the last five years, whereas for PV the power output is based on the output of 2014. Effectively, this means that for every year between 2017 and 2023 the per unit power output of RES is fixed. Applying a Monte Carlo analysis would provide better insights regarding the stochastic effects of wind speed and solar radiation.
- The contribution of interconnections is considered equivalent to a thermal unit of 500MW and 95% availability. No robust reasoning is provided for this assumption. Moreover, it is mentioned in the report that this modelling assumption on the contribution of interconnections is extremely conservative, yet, a sensitivity analysis has not been made. More detailed evaluation of the interconnectors contribution could be made based on ENTSO-E's MAF 2016 method. This could be used as a basis for a much more realistic (and less conservative) modelling of the

available contribution of interconnectors to adequacy. The seasonality of the Available Transfer Capacity (ATC) should also be taken into account.

- No information is provided on how the extra demand due to the interconnection of Crete has been calculated. It is not clear whether the interconnected island's load is modelled considering a portion of its annual demand ex-ante to be covered by the mainland System after the connection or as a different area, as it should. Although, in principle, those interconnections are meant to increase the national Social Welfare (local expensive generation feeding local demand is substituted by cheaper power imported from mainland), the possible rapid growth of local RES generation together with the availability of local dispatchable generation to solve adequacy issues in mainland could foresee, at the target year, operational conditions where the power flow is reversed. It is suggested to evaluate this situation and explain the rationale behind the used approach, taking into account the possibility to model the - nowadays - electric islands as different areas. This is important, since one of the reasons for the adequacy problems in 2020 and 2021 is the interconnection with Crete.
- Concerning the annual requirement for maintenance of generating plants, the periods used in the study for each type of thermal plant are given without analysis or explanation. It could be worth including the reasoning behind these values, along with a historical statistical analysis.
- It is unclear whether or not, and if yes how, the reserves provision is considered in the methodology. More information should be provided in the report on how they are calculated and if they are used in the analysis.
- The maximum capacity of thermal units is considered as fixed in the study. However, the ratings of different resources change as a result of seasonal trends in temperature, which affect the maximum output of thermal units. In [18] the impact of seasonal trends on rated capacity was taken into account by having monthly capacity values for the thermal resources by generation type. It is noted for example, the capability of the gas fleet in the Southwest region is reduced by 5% in the summer compared to the winter due to the effects of temperature on output.
- Demand Response should be clearly identified among the potential sources of additional capacity, not only thermal units. This is clearly acknowledged in both ENTSO-E and national generation adequacy assessments, it is a fundamental aspect of the EC policy, and has clear implications on the possible capacity mechanism design.
- The ex-ante definition of the operation of reservoir hydro units (peak shaving) does not necessarily lead to the best global optimum in security of supply terms. Allowing the optimization algorithm to define the operational regime of reservoir hydro units would be a much more robust approach.
- The reliability standard for LOLE is taken as 2.4 hrs/year derived from the 1 day in 10 years. No information is provided on how this standard was derived. It should be noted that this is less than that set for other countries, where probably the Value Of Lost Load (VOLL) is larger, such as France (3h/yr LOLE). Yet, it should be mentioned that the reliability standard that each country will follow falls completely into its responsibility. However, as mentioned in the introduction, one of the EC's conclusions from the sector inquiry is that a rigorous adequacy assessment against a well-defined economic reliability standard is crucial for identifying risks to the security of supply.
- According to [16] blocks of thermal units are placed in a priority list in ascending order of their incremental cost and dispatched according to this list. However, it appears that the technical constraints of the thermal units (ramp rates, minimum

up and down times, start-up and shut-down times etc.) are not taken into account. This should be clearly stated.

- It is stated that thermal units of less than 40MW are not mentioned in Table 4.2 of ADMIE's study. It is unclear whether these units are taken into account in the modelling, as it should, and if yes, how.
- It is mentioned that each year of the considered period is examined with the granularity of one week. However, it is not clear what is the granularity considered within the week. In [16] it is noted that the software constructs load demand curves, either one per week or four per week, one for peak load hours, one for low load hours, one for Saturday and one for Sunday. It would be worth providing more details on the methodology within the week and also the method of constructing the load demand curves.
- Regarding the calculation of the surplus or additional generation to return the system to the reliability standard, it is not mentioned, whether or not the amount of surplus or deficit plant is given in terms of a Perfect Plant. A Perfect Plant may be considered as a conventional generator with no outages. However, in reality, no plant is perfect, and the amount of real plants in surplus or deficit will differ.
- The difference between "installed capacity" and "net capacity" should be clarified.
- A section in the report highlighting the assumptions and limitations of ADMIE's implementation methodology could be a valuable addition to the report.

4 Comparison of generation adequacy methodologies

4.1 Introduction

The scope of this Section is to compare the main characteristics of the two generation adequacy methodologies described so far, the one of ENTSO-E and the one of ADMIE. There isn't currently a commonly accepted procedure for generation adequacy and various practices have been employed by different Member States and various reliability indexes were used for the adequacy assessment. Under the Third Energy Market Package (1 COM (2014) 910 final of 16.12.2014), electricity, within a coupled market, would be efficiently traded across Europe. Thus, a coordinated process of generation adequacy estimation becomes an important issue, as its effect stretches outside national bounds.

4.2 Methodology

- ADMIE's analysis is performed annually for the seven year period covered in the study (2017-2023).
- MAF 2016 examines discretely two years 2020 and 2025.
- ADMIE is using analytical probabilistic model (convolution techniques). For every scenario, and for every year considered, the annual probabilistic indicators LOLE and EUE are calculated.
- ENTSO-E determines the generation adequacy with a market-based probabilistic modelling approach. Forecasts for the generation and transmission capacity and demand are used through probabilistic Monte Carlo simulations to compute the reliability indicators.
- ADMIE uses the PROSIM software for the simulations. Each year of the considered period is examined with the granularity of one week.
- ENTSO-E uses four tools for the analysis: ANTARES, BID3, GRAGE, and PLEXOS. For each tool and for each forecast year (2020 and 2025) N number of simulation runs (Monte Carlo samples or years) are constructed by the combinations of:
    - 14 Wind – PV – Temperature climatic year situation
    - Three hydrological situations, dry, normal, and wet.
    - 200-300 situations for random outages samples of thermal units and HVDC links.

For each year, 2020 or 2025, and each of the *N* Monte Carlo samples, hourly simulations of the whole interconnected Pan-EU perimeter are performed, resulting into 8760 hourly variables calculated for each simulation run.

Furthermore, a set of time series of correlated load / wind / solar production are used in the simulations, according to the climatic correlations provided by ENTSO-E Pan-European Climate Data Base (PECD). Different types of hydro conditions, available capacity of units generating supply and reflecting various possible outcomes are created for each of the phenomena considered above. These series are then combined in sufficient numbers to give statistically representative results including shortages/scarcity situations (risk of demand not being met due to a lack of generation).

MAF is using probabilistic Monte Carlo approach where all climate years (2000-2013) are chosen one–by–one. Each climate year choice, meaning each combination of load (accounted temperature sensitivities), wind and solar time series, is combined with the three possible hydro conditions (wet, dry, normal). Each choice of climate and hydro condition is further combined with 200-300 realizations of Force Outages of thermal units and HVDCs. The main assumption for the market simulation engine is perfect competition.

The tools calculate the marginal costs as part of the outcome of a system-wide costs minimization problem. Such mathematical problem, also known as "Optimal Unit Commitment and Economic Dispatch", is formulated as a large-scale Mixed-Integer Linear-Programming (MILP) problem.

The Greek generation adequacy assessment mainly uses historical data, elaborated with GDP projections to form load series. Historical data, along with the capacity projections for new RES installations, are used to estimate (future) production from RES. Climatic correlations and stochastic nature of the data are not taken into account in the study.

For each scenario considered, the stochastic nature of forced outages of conventional generating units is taken into account using the Equivalent Demand Forced Outage Rate ($EFOR_D$) of the units. $EFOR_D$ is the probability a generator will fail completely or in part when needed.

The model assumes known the chronological load time series (8760 hourly loads). The demand is represented by a load duration curve, which is then inverted and the time axis is normalized to 1. First the model simulates the operation of non-dispatchable units and the hydro units (using a peak shaving technique) resulting to a new annual chronological time series. The resulting load series has to be served by the thermal units of the system, taking into account the interconnections with neighbouring countries in case of emergency. Blocks of the thermal units are dispatched in ascending order of their incremental cost. According to [16], page 125, the dispatched hydro plants (excluding pumping units) are modelled as an equivalent unit whose operation is simulated by modifying the load duration curve (peak shaving) so that the total energy produced from the hydroelectric generators correspond to each hydro energy scenario under consideration.

4.3 Demand

In the 2016 edition of the generation adequacy assessment of ENTSO-E, a temperature-sensitive load model was developed. The probabilistic modelling of the power demand in MAF 2016 incorporates the sensitivity of load to weather changes by identifying the sensitivity zones (heating, cooling and comfort zone) defined by the temperature gradient ($\frac{\Delta L}{\Delta T} \gtreqless 0$). Moreover, two different linear approximation methods have been adopted to identify the most suitable approximation of the (hourly) load fluctuation to temperature variations. For the calculations, the ENTSO-E PECD with 14 climatic years was used (2000-2013).

On the other hand, in the Greek generation adequacy assessment, the data used was based on the national TYNDP 2017-2026, taking into account historical data and the expected evolution of the GDP. The GDP forecasts from EU and IMF documents were used. The temperature sensitivity of the load has been tracked in the historical data, influencing the load peaks, but the respective correlation has not been elaborated.

According to the data package published with the MAF 2016, ADMIE has provided ENTSO-E with an hourly total load profile for 2020 (Figure 4). As mentioned before, for this year the summer peak is forecasted as 10415 MW, which corresponds well with the forecasted summer peak used in ADMIE's adequacy study (Table 13) for the reference demand, which is 10410 MW. However, this is not the case for the winter peak, which is forecasted as 9012 MW for 2020 in the MAF 2016 but is increased to 10000 MW in ADMIE's study for the reference demand (Table 14). Although the load profile in MAF 2016 corresponds to total load and not transmission system load, the winter peak, since it occurs in the evening when there is no PV production, should be approximately the same. This difference should be clarified further.

Furthermore, as mentioned before, ENTSO-E is using normalised load profiles based on average historical temperatures. This load profile is then scaled according to the simulated climatic years based on the thermo-sensitivity of demand. It is not mentioned whether the provided load profile by ADMIE is normalised, how this normalisation was carried out and what thermo-sensitivity value of demand was used. As this is an important parameter, ADMIE should provide more information regarding the provided load profile in MAF 2016 and its connection with the demand forecast used in the TSO's adequacy study.

No explicit representation of Demand Side Management (DSM) and Demand Side Response (DSR) measures are included in the MAF or in the ADMIE's study.

4.4 Supply

In the 2016 MAF, the generation model includes projections on the future installed capacity and the availability of the generation units. Unavailability of the power system elements is included in the simulation in two ways: i) Forced Outages and ii) Planned Outages. No information is provided on the availability indicators used for the thermal generation. Furthermore, no information is provided on the aggregation of the power plants used in the modelling.

For the RES generation, the PECD load factor and temperature datasets (synthetic hourly time series derived from climate reanalysis models) enable a coherent simulation of variable RES production and weather-dependent load variation. Furthermore, the various meteorological data are also geographically correlated. Neighbouring countries could be affected by the same meteorological effects; therefore, it is essential to maintain this geographical correlation between countries in terms of climate variables.

A global set of values for fuel and CO_2 prices is used for the whole Pan-European perimeter. These values are taken from the IEA "Current Policies" scenarios at the World Energy Outlook 2013 for year 2020.

Three sets of data were used for the hydro generation, each of them corresponding to a hydrological "normal" year (e.g. closest hydrological year to the 50% percentile), "(most-) dry" year and "(most-) wet" year were prepared.

Considering the geographical proximity of countries, it is expected that their hydrological conditions should be closely correlated, i.e. when there is a dry year in Switzerland, it should also be dry in Austria and France, and vice versa. For the PLEF region, the hydrological years were mostly based on the Swiss historical hydrological data, which include more than 10 years of inflow, river flow and hydro production data.

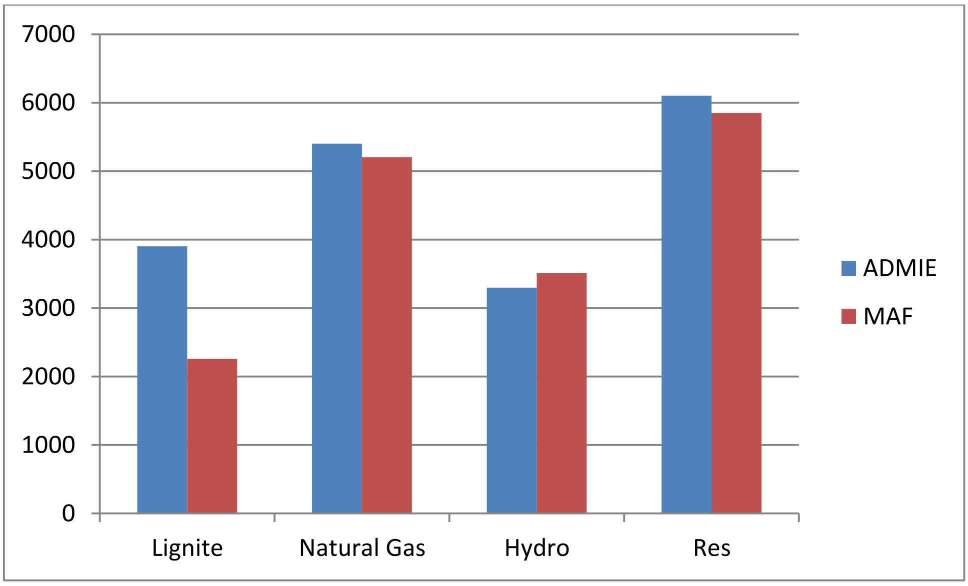
In the ADMIE's analysis a basic scenario for the evolution of the power generation system during the period 2017-2023 is presented based on the planned commissioning and decommissioning of thermal units. The unavailability of the thermal units, expressed as EFORD were taken into account in the model by using the respective values of the ADMIE Table of Available Capacity for the Year October 2015-September 2016. For the new units, typical values of the index were assumed. The evolution of fuel and CO_2 prices is not examined.

The hourly operation of all the RES (excluding PV) for each year is formed taking into consideration the average monthly loading of the last five years and the capacity that has been assumed for each scenario of RES integration. Especially for PV, which has a forecasted production, the hourly generation series for each year is formed by amending the respective series from the year 2014 so that it corresponds to the forecasted capacity. The correlation of weather with the RES production has not been assumed.

For the hydro units, three scenarios (dry, medium and wet year) have been formed based on the statistical analysis of historical data and correspond in annual production of 2200GWh, 4200GWh and 5700GWh, while the maximum peak shaved due to the operation of the hydro units was assumed to be 2200MW, 2400MW, and 2700MW respectively. For each scenario the extra hydrological generation from the operation of the pumping units is assumed and simulated by the model PROSIM.

Comparing the forecasted generation mix in the studies of ENTSO-E and ADMIE (Figure 5 and Figure 11) for the year 2020, which is the only common year between the two studies, one finds differences between the considered values, as seen in Figure 13. For example, the lignite generation considered in MAF 2016 for 2020 is 2256 MW whereas the lignite generation in ADMIE's study for 2020 is 3900 MW. The value taken for next year (2021) in ADMIE's study is 2200 MW, which is closer to the value used in the MAF 2016. Although the differences could be attributed to updated information available for the most recent of these studies, care should be taken to align the input data with regard to the evolution of the generation mix in national and pan-European studies. If there is a change in the forecasted values this should be clearly reasoned and stated.

Figure 13: Generation mix comparison for 2020 for MAF 2016 and ADMIE's generation adequacy study



Source: [5] and from [4], excel sheet available online https://www.entsoe.eu/outlooks/maf/Pages/default.aspx

4.5 Scenarios

In MAF 2016, a single scenario can be found for 2020 and 2025. The scenarios are referred to as "Expected Progress/ Best Estimate" scenarios and give the forecast for the supply. MAF uses a Sequential Monte Carlo approach to estimate the stochastic nature of the demand and RES generation, both by using the PECD, and hydro generation. Each choice of climate (load and RES) and hydro condition is further combined with 200-300 realizations of Forced Outages of thermal units and HVDCs.

A sensitivity analysis is performed too, as follows:

1. *Base case*: Day-ahead adequacy. Operational reserves do not contribute to adequacy
2. *Sensitivity case I*: Day-ahead adequacy + operational reserves contributing to adequacy; 'real time' adequacy
3. *Sensitivity case II*: Sensitivity Case I + HVDC forced outages

In the generation adequacy of ADMIE assessment there are 9 scenarios taken into consideration.

For the demand, three scenarios are considered: Reference, Low, and High demand. In the forecasted values system losses and demand served by distributed generation are included.

Furthermore, the forecasted demand from the connected islands Andros, Siros, Tinos, Paros, Naxos and Mykonos is included from 2017 onwards. The demand from the mainland system towards Crete for the period 2020-2023 is not included as it is estimated through the simulations for each scenario separately.

For the supply and especially for the thermal units, there is only one scenario taken into account, the reference scenario based on the planned commissioning and decommissioning of thermal units.

For the RES there is a basic scenario referring to the forecasted installed capacity for technology and for each year under consideration. The stochastic nature of RES and the climate sensitivity is not taken into account in the estimations.

For the hydro units there are three scenarios based on the hydrological conditions: Dry, Medium, and Wet year.

For the interconnections there are two scenarios considered: with and without interconnectors. The contribution of the interconnectors has been assumed as the equivalent of a thermal unit of 500MW base load with 95% of availability.

4.6 Consideration of reserves

In the simulations considered in the MAF report, a certain capacity from the provided Net Generation Capacity (NGC) is considered to cover each TSO’s reserve requirements. In the Base Case simulations, this capacity is considered as not contributing to adequacy (D-1 situation), while in the Sensitivity simulations, this capacity is assumed to contribute to adequacy (real-time situation). In the report of ADMIE, no information is provided on how these requirements are calculated and modelled. Nevertheless, it is mentioned in the Handbook [16] that the necessary operational secondary reserves are taken into account when modelling the hydro.

4.7 Interconnectors

Within the MAF 2016 Adequacy Reference Transfer Capacities values for the representation of cross-borders capacity have been setup in a way to ensure consistency with the TYNDP 2016 reference capacities. The main parameters included in the modelling are:

- Adequacy reference transfer capacities values
- Simultaneous importable / exportable capacities
- Projects with the positive impact on the transfer capacities (Regional Investment Plans of TYNDP 2016).

MAF considers also the exchanges with non-ENTSO-E countries, these are modelled in the form of annual hourly data series defined by TSOs of those ENTSO-E countries, which expect the exchanges on the borders with their non-ENTSO-E neighbours in particular time horizon.

The contribution of the interconnectors is taken into account in the generation adequacy assessment of ADMIE for the system adequacy and the system sufficiency (adequacy of the system with no interconnectors). For the scope of the analysis the contribution of the interconnectors is regarded as the equivalent of a thermal unit of 500MW base load with 95% availability.

4.8 Indicators

The indicators traditionally used for the adequacy assessment are three: Energy Not Supplied (ENS); Loss Of Load Expectation (LOLE) and Loss Of Load Probability (LOLP). Both ADMIE and MAF compute ENS and LOLE.

In the generation adequacy assessment of ADMIE, for every scenario, and for every year considered, the annual probabilistic indicators LOLE and EUE are calculated. The value of 2.4 hours/year has been adopted as LOLE target.

In the MAF, and in order to obtain a satisfactory analysis of the influence of different parameters on the results (i.e. input data, outages and modelling with the use of different tools), various sensibility analyses have been conducted. Results from the four different tools for LOLE and ENS and with respect to 3 cases (base case, and the two sensitivity cases) are rendered for each country as averages and the 95th percentile of ENS (MWh) and of LOLE (hours), for each target year (2020 and 2025).

Here lies one of the main differences between the two employed methodologies, i.e. the analytical probabilistic technique used by ADMIE and the sequential chronological probabilistic method employed by ENTSO-E. In the first, case only average reliability indices are calculated, while in the second the full probability distribution function of the reliability indices is deduced. The latter can be considered a better tool for informed policy decisions since the impact of extreme cases can also be investigated.

4.9 Results

As presented in previous sections, ENTSO-E and ADMIE have used different methodologies to assess the generation adequacy, the former for the whole European interconnected system, and the latter for Greece.

ENTSO-E has calculated the reliability indices only for 2020 and 2025, whereas ADMIE for every considered year. Therefore, the only common year between the two studies is 2020. ADMIE has calculated LOLE and EUE for the considered generation production scenario (Baseline Scenario) and a combination of three demand scenarios and three hydrological years, with interconnections, nine calculations in total. The LOLE and EUE for 2020 (see Table 18) range from 0.387 hrs/year and 70 MWh respectively, for a wet hydrological year and low demand scenario, to 22.884 hrs/year and 6161 MWh respectively, for a dry hydrological year and high demand scenario. On the other hand, ENTSO-E has included, within the sequential Monte Carlo simulation the uncertainties of the RES production, the temperature sensitivity of load and the probability of hydro conditions. In addition, as mentioned before, ENTSO-E has provided results for each country from four different tools. The average LOLE and EUE for 2020 for the base case (see Table 8 and Table 9) range from 0 hrs/year and 0 MWh respectively for one tool, to 4.7 hrs/year and 1081 MWh respectively for another tool.

According to ADMIE, as mentioned in the comments by the Greek TSO in the ENTSO-E MAF 2016 report [4], the main difference between the methodology used in MAF and the one used by ADMIE is in the estimating the contribution of interconnections. While ENTSO-E in the MAF 2016 considers a pan-European perimeter for simulations, ADMIE only considers the Greek generation system and interconnections are taken into account through specific scenarios.

As stated by ADMIE in the country comments in the ENTSO-E MAF 2016 report, both studies appear to raise concerns about system adequacy for the Greek generation system in 2020, due to the simultaneous retirement of the lignite fired units of Kardia and Amyntaio by 2020.

4.10 Remarks

Approaches to generation adequacy assessment vary between countries [10] not only with regard to the implemented methodology, but also with regard to the generation and demand models used to estimate these elements. Ultimately, irrespective of the type of methodology, the demand and generation estimates are combined to check if there will be enough resource capacity to cover the demand. Therefore, the assumptions used to project into the future the resources and demand will have an important impact on the results.

Chapters 2 and 3 presented the main elements of the latest generation adequacy methodologies of ADMIE and ENTSO-E. Table 26, at the end of this section, compares these elements of the methodologies. Also, provided below are some remarks based on the available information.

- As previously mentioned, regarding the methodology, ADMIE has used analytical probabilistic model whereas ENTSO-E recently moved to a sequential Monte Carlo simulation. Although both are probabilistic approaches, there are fundamental differences in the way data requirements are taken into account, and in the provided output parameters. Compared to analytical probabilistic models, sequential Monte Carlo simulations can consider virtually all stochastic aspects and contingencies of a power system, such as random events (outages and repairs of elements), dependent events, load variations and variations of energy input (hydro-generation and RES production), in a more realistic chronological way. In addition, they can provide a wide range of output parameters, such as complete probability density functions and additional time-related indices, such as frequency and duration of load loss. Furthermore, they can model situations where one basic interval has a significant effect on the next interval, such as the effect of hydro-generation. The only downside is that, due to the necessary very high number of simulations, they are very computationally intensive, which leads to the need to apply some simplifications to reduce the simulation time. However, the advantages outweigh the disadvantages and this is the reason why there is a tendency in Europe [10] and in the USA [18] to move towards this type of methodology. For the above reasons, **it is recommended that ADMIE should move towards sequential Monte Carlo simulation methods**.
- One major difference between the two approaches, mainly due to the implemented methodology, is the way the demand and RES production is taken into account. ADMIE is estimating demand based mainly on historical data and mostly with GDP projections, however, there is no analysis done to calculate the historic correlation between GDP and demand. Furthermore, once the estimations for the three demand scenarios are carried out they are used for each simulation without taking into account the temperature dependency of load. In addition, RES production (except PV) is estimated based on average monthly utilisation coefficients of the last five years, whereas for PV the power output is based on the output of 2014. In comparison, ENTSO-E is taking into account the impact of different climatic conditions on the variable RES output and on the load by using correlated time series of wind, demand and solar for 14 years of climate conditions, through the use of the Pan-European Climate Database (PECD). Therefore, it is recommended that, coupled with the move towards sequential Monte Carlo simulations, **ADMIE could make use of ENTSO-E's Pan-European Climate Database to take into account the stochastic nature of temperature, wind speed and solar radiation and the spatial-temporal correlation among these variables**, or use country specific climate scenarios, as the French TSO has done [19]. In addition, when modelling neighbouring countries, it is essential to maintain the geographical correlation between countries in terms of climate variables.

- Hydro production estimation is not an easy task, due to the many factors affecting energy produced by a hydro-generation (stochastic nature of natural inflows, availability of water stored in reservoirs, water usage policies and environmental releases, etc.). Long-term historical data are used to analyse hydro generation and derive distinctive hydro regimes. This approach has been used by both ENTSO-E and ADMIE to derive three different regimes, dry, normal and wet. However, ENTSO-E has associated these profiles to their corresponding probability, which represents the likelihood/frequency of its occurrence (i.e. 10% probability for dry, 80% probability for normal and 10% probability for wet profile). These profiles were taken into account when building the Monte Carlo simulations. On the other hand, ADMIE has not assigned probabilities to each regime, electing the derivation of distinct scenarios for each of these profiles. In addition, ENTSO-E, due to the use of market-based probabilistic techniques is able to optimise the hydro-thermal coordination. ADMIE's approach to define ex-ante the operation of reservoir hydro units (peak shaving) does not necessarily lead to the best global optimum in security of supply terms. Therefore, it is recommended that, coupled with the move towards sequential Monte Carlo simulations, **ADMIE should assign probabilities to the different hydro profiles and use an optimization algorithm to define the operational regime of reservoir hydro.** As always the availability of historical data is of paramount importance.
- Given the impact of hydro on adequacy metrics in the ADMIE study, the statistical analysis for the assignment of probabilities to hydro profiles for Greece should be considered in the next ENTSO-E MAF report.
- There appears to be a big discrepancy in the evolution of the generation mix between the studies of ADMIE and ENTSO-E study for the year 2020. **An effort is required to align the input data with regard to the evolution of the generation mix in national and pan-European studies.** If there is a change in the forecasted values, it should be clearly reasoned and stated.
- There is a discrepancy in the forecasted winter peak for 2020 between MAF 2016 and the study of ADMIE. More information should be provided by ADMIE for the reason of this discrepancy.
- ENTSO-E is using normalised load profiles based on average historical temperatures. This load profile is then scaled according to the simulated climatic years based on the thermo-sensitivity of demand. It is not mentioned whether the provided load profile by ADMIE is normalised, how this normalisation was carried out and what thermo-sensitivity value of demand was used. As this is an important parameter, **ADMIE should provide more information regarding the provided load profile in MAF 2016**.
- The contribution of interconnections is another major difference between the two approaches. ADMIE considers the cross-border exchanges as equivalent to a fixed -capacity thermal unit of 500MW and 95% availability. On the other hand, ENTSO-E models the whole European interconnected system conducting market studies based on NTC/ATC Market coupling, where the network constraints between the market nodes are modelled as limits only on the commercial exchanges at the border. **It is recommended that ADMIE conducts a more detailed evaluation of the interconnectors contribution based on ENTSO-E's MAF 2016 method.** This could be used as a basis for a much more realistic (and less conservative) modelling of the available contribution of interconnectors to adequacy. Also of great importance is to take into account overlapping peak demand periods at neighbouring countries. It should be noted that even ENTSO-E's approach has limitations, as the cross-border interconnector assumptions do not account for seasonality and operational constrains and flow based market methods are not used, leading to a conservative approach. However, ENTSO-E has proposed these improvements for future MAF reports.

- As mentioned before, the tools used by ENTSO-E calculate the marginal costs as part of the outcome of a system-wide costs minimization problem, known as "Optimal Unit Commitment and Economic Dispatch". In other words, the program attempts to find the least-cost solution while respecting all operational constraints (e.g. ramping, minimum up/down time, transfer capacity limits, etc.). Due to ADMIE's approach, it appears that the technical constraints of the thermal units (ramp rates, minimum up and down times, start-up and shut-down times, etc.) are not taken into account. **It is recommended that**, coupled with the move towards sequential Monte Carlo simulations, **the technical constraints of the thermal units are taken into account.**
- In the simulations considered in ENTSO-E's MAF 2016 report, a certain capacity from the provided Net Generation Capacity (NGC) is considered to cover each TSO's reserve requirements. ENTSO-E is conducting sensitivity simulations where this capacity is assumed to contribute to adequacy (real-time situation). In ADMIE's generation adequacy study it is not mentioned whether or not, and if yes how, the requirement for reserves is taken into account. **It is recommended that ADMIE carries out sensitivity simulations taking into account the reserves provisions.**
- Demand Side Response (DSR) is a key element for the adequacy of the system and a fundamental aspect of the EC policy, towards the move to resource adequacy. During peak hour times this tool can provide the right signal to some customers to reduce their consumption. However, it is very difficult to include in the regional or pan-European models due to the heterogeneous demand side topologies of each Member State. Therefore, no explicit representation of Demand Side Management (DSM) and Demand Side Response (DSR) measures has been included in ENTSO-E's MAF 2016 or in ADMIE's study. It is envisaged that ENTSO-E models DSM in future reports. **It is recommended that the potential benefits of DSM/DSR to the adequacy of the system are investigated.**
- ENTSO-E calculates the reliability indicators for the years 2020 and 2025 whereas ADMIE calculates the indicators for every year considered. ENTSO-E has performed the European generation outlooks in the past for three forecasted years. Moving to the new methodology with MAF 2016, ENTSO-E has provided results for the two aforementioned years. It is also worth mentioning that there is a difference to the required computational time between the two methodologies that could potentially restrict the computed number of years. Running sequential Monte Carlo simulations require a lot of computing power and time, compared to an analytical probabilistic model. As an extreme example of computational time requirements, the National Renewable Energy Laboratory (NREL) and the U.S. Department of Energy (DOE) conducted the Eastern Renewable Generation Integration Study (ERGIS) where they simulated one year of power system operations to understand regional and sub-hourly impacts of wind and PV by developing a comprehensive UC&ED model of the Eastern Interconnection [20]. The model included over 7,500 generating units, 60,000 nodes, and 70,000 transmission branches (lines and transformers). They estimated that to run the model for a full year would require 545 days of computational run time. To reduce these infeasible simulation times they used partitioning and parallel simulation methods with a high performance computing system and partitioned the annual simulations into 73 independent simulation horizons. This succeeded in reducing the computational time to a more manageable 19 days. Another difference between the two studies is that ENTSO-E, also probably to save computational time, has aggregated the generating units per type (i.e. nuclear, lignite, gas, etc.) whereas ADMIE has modelled each individual thermal generating unit. ENTSO-E does not provide the unavailability factors for generators used.
- Neither ENTSO-E nor ADMIE's study have provided further sensitivity scenarios regarding the economic viability of the generation mix. It is mentioned in [4] that

TSOs were asked to apply the best of their knowledge on the "economic viability" of the scenarios provided for MAF. Nevertheless it cannot be 100% guaranteed that the forecasted generation mix used, will be economically viable in 2020 and 2025. It is also noted that ENTSO-E and TSOs are aware of the importance of these assumptions regarding input data which affects the 'likelihood of units to run and stay online' within the market modelling assessments performed in MAF, since these input data items are crucial to perform any sensible sensitivity regarding 'viability' of the (central) best-estimate scenarios collected by TSOs. It is worth mentioning that a joint study to take into account the economic viability of the generation mix has been carried out by EirGrid and SONI – Irish and Northern Irish TSOs, respectively – in agreement with their regulatory requirements [21]. In the study for each generator the energy market and ancillary service revenues are calculated and taken into account in the adequacy assessment. The methodology entails: (a) the estimation of O&M costs and Capital costs for each generator unit, (b) calculation of the generation volume for each unit using the market model, (c) calculation of the required average price using (Fixed Annualised Cost/Generation Volume) for each unit, (d) calculation of the ancillary service revenues for each unit based on a unit's running and the system service tariffs, (e) the removal from the generation portfolio of the generators whose combined revenues from energy and ancillary services payments are less than their annual costs and (f) carrying out the adequacy studies using the updated generation portfolio. **A sensitivity analysis on the economic viability of the generation mix could be carried out based on the joint EirGrid and SONI study.**

- Neither ENTSO-E's nor ADMIE's study take into account possible shortages of fuel availability. It is important to recognise that the future Security of Supply experienced by end-consumers depends upon the combined reliability of fuel (or other primary resource supplies), generation, transmission, and distribution. It is recognised that a proper estimation of possible shortages of fuel requires building and running combined, for example in the case of gas fuel availability, gas and electric power models that can be very difficult to prepare and run. However, **a sensitivity analysis based on best estimates of fuel availability (possibly from historical statistical analysis) should be carried out.**
- It is also worth mentioning that neither ENTSO-E's nor ADMIE's study take into account the transmission adequacy (hierarchical level II, or so called system adequacy), which includes both the generation and transmission facilities in an adequacy evaluation. Essentially the modelled zones are considered as congestion free zones or 'copper plate' zones. However, there are situations where although a supply resource is available, in reality, due to internal congestion, the power is restricted. Examples of this are outages of transmission equipment or high RES production in a congested area. This could have an impact on the adequacy of the system. An example of a study that has taken into account the complete system (generation and transmission) is the aforementioned one by NREL in the USA [20], however, as noted, the required computational time and resources should not be underestimated.
- The need for harmonisation of models and data assumptions and inputs between the national and European adequacy and flexibility studies is evident from the comparison. Best European and international practices should be adopted based on the current and future evolution of the power system in order to provide a common assessment methodology.

Table 26. Comparison of ADMIE and ENTSO-E methodologies

Generation Adequacy Assessment Elements		ENTSO-E (benchmark)		ADMIE (comparison with the benchmark)
		Current approach	**Foreseen improvements**	**Current approach**
Methodology	**Modelling tools**	4 different tools		1 tool
	Modelling approach	Market-based sequential Monte Carlo stochastic modelling (day-ahead adequacy)	flow-based (stochastic) market methods (day-ahead adequacy)	Analytical probabilistic analysis Priority list in ascending order based on the thermal units' incremental cost
	Stochastic analysis	Load, RES, forced outages, and hydro generation		Only forced outage rate for thermal units Deterministic approach only for RES, load and hydro
	Geographic scope	Pan-European with connection with non-ENTSO-E countries		Greek system and scenarios with interconnections with abroad
Demand	**Modelling of load**	Temperature sensitivity of load based on climatic years		3 levels of demand (no probability specified)
	Climate data	Pan-European Climate Data Base (PECD 1.0)	Improvement of data set (PECD 2.0)	Not considered
Supply	**Thermal portfolio Capacity**	Net Generation Capacity form Pan-European Market Modelling Data Base (PEMMDB)	Revision of details and assumptions (included data on anticipated decommissioning of power plants)	Planned commissioning and decommissioning
	Fuel and CO_2 prices	WEO2013 Current policy scenario for 2020 (EIA 2013)		No information provided
	Availability of generation units	Planned and forced outages		Planned and forced outages based on the Equivalent Demand Forced Outage Rate ($EFOR_D$)
	RES production	PECD load factors (synthetic hourly time series derived from climate conditions) and weather data	Improvements related to PECD 2.0	Average monthly loading of the last five years for wind. PV output is fixed at output of 2014. No correlation among weather data
	Hydro	3 possible hydro years with associated probability and based on available data, correlated per region	Improvements in modelling with more available hydrological data	3 possible hydro years based on historical data, distinguished for annual production and peak. No probability is associated to each hydro year. Pumping units modelled with PROSIM
Scenarios	**Time horizon**	2020 and 2025, with hourly granularity		From 2017 to 2023 with one week granularity
	Sensitivity	3 cases (1) no consideration of reserve (2) Consideration of reserve (3) HVDC forced outages		Baseline scenario with combination of 3 levels of demand and 3 hydro years with or without interconnections. Alternative scenarios: (1) Crete interconnection; (2) Peloponnese infrastructure delays (3) new lignite plant Ptolemaida V is delayed (4) Withdrawal of two CCGT units

Reserves		Consideration of operational reserves	Elements of Network Codes, impacts of sharing operational reserves on a real time basis, across synchronously-connected countries in ENTSO-E	No information provided
Interconnectors	**cross-border interconnections**	Based on NTC/ATC-Market Coupling (NTC/ATC MC). Network constraints between the market nodes are modelled as limits only on the commercial exchanges at the border	Assumptions to account for seasonality and operational constrains	Contribution of the interconnectors equivalent to a thermal unit of 500MW base load with 95% availability
	HVDC lines	Forced outages of HVDC		Not considered
	Commercial import/export	Simultaneous importable / exportable capacities;		Not considered
	Exchanges with non-ENTSO-E countries	Exogenously predefined by each neighbouring TSO		Not considered
Indicators		LOLE, ENS (mean, P50,P95)		LOLE, EUE

5 Flexibility assessment

5.1 Need for flexibility

Even though there is not a widespread accepted definition, flexibility of a power system can be considered its ability to adapt its operation to both predictable and unpredictable fluctuating conditions inside certain technical and economical boundaries [22]. Albeit the power system should exhibit the above capability in all time-frames, flexibility usually refers to time horizons from the Day-Ahead to intra-hour.

The interest in power system flexibility has risen the last years due to the increased penetration of variable, limitedly predictable RES generation technologies (mainly wind and solar) as a result of decarbonisation policies. It should be noted that power system operators always faced issues regarding the variability and the limited predictability of demand and generation units (unplanned contingencies). It is the increase in the magnitude of variability and forecast uncertainties under high penetrations of RES that makes flexibility a significant issue in both planning and operational procedures. Moreover, in contrast to the vertically integrated electricity companies of the past, the deregulated market environment introduces added challenges: In the long-term, policy makers can only indirectly influence investments. In the short-term, power system operation is only to an extent administered by the TSO, since the actions of market players have a significant impact on system balancing, including provision of flexibility, especially in self-dispatched markets.

In contrast to the classical generation adequacy assessment where of interest is whether the installed generation capacity in the future will be adequate to cover the volume of expected demand, assessment of flexibility requirements focuses on two other issues:

1. The capability of the system to provide adequate levels of operational reserves to cover for generation and load limited predictability. Given the limited predictability of RES sources, such as wind and solar, the needs for operational reserves generally increases.
2. The capability of generating units, and demand response, to follow at each point of time the load. Given the multi-hour and intra-hour variability of wind and solar plant output, the ramping requirements on the dispatchable generation fleet increase. In addition, dispatchable plant such as conventional thermal units and hydro, have their own technical constraints (ramping rates, minimum up and down times, minimum stable output levels) which makes the challenge even greater.

Currently, the assessment of flexibility requirements for power systems is focused on whether the power system has an adequate level of flexibility resources to face the aforementioned technical challenges and/or to evaluate future flexibility needs in a qualitative and quantitative manner. However, it should be noted that the actual availability of these resources is not only a technical matter, but also a subject of the regulatory framework of electricity markets. Factors such as the existence of a central or self-dispatched system, the structure of the ancillary services market, the type of financial support schemes on RES etc. can play a decisive role. Moreover, there may be trade-offs between the economical provision of flexibility and other policy goals such as de-carbonisation of the power system. An obvious example are variable RES which can act as sources of flexibility, but at the cost of curtailed operation [18]. Hence, flexibility requirement assessments should be considered more as studies enabling policy makers and regulators to make informed decisions rather than analyses providing definitive answers.

In what follows, the flexibility assessment of Elia (Belgium TSO) is presented. This assessment is probably the most thorough flexibility assessment in Europe. Developments on the other side of the Atlantic are briefly discussed in Section 5.5.

5.2 Elia's flexibility assessment review

5.2.1 Introduction

In April 2016, Elia published the "Study regarding the 'Adequacy and flexibility needs of the Belgian Power System'", henceforth referred as B_GA&FE [11]. The study covers both the assessment on generation adequacy and flexibility requirements for the period 2017-2027.

The study was conducted after a request from the Belgian Federal Ministry of Energy (21 December 2015) with two specific goals for Elia (B_GA&FE, Section 2.1.1):

1. To evaluate the future needs in MW on adjustable national capacity in order to satisfy the legal criteria on security of supply. In particular, there was an explicit request to analyse the flexibility requirements and characteristics.
2. To present potential options on measures or market mechanisms needed to cover the identified needs.

It should be noted that the above decree from the Belgian Federal Ministry of Energy shaped to a significant degree the methodological approach followed by Elia, as shown in the following Sections.

The main characteristics of the Belgian power system could be summarised as follows:

- Central place, strong interconnections and advanced market coupling with the other countries of the Central West Europe Region. Interconnections play a significant role for the security of supply of the Belgian power system. On the other hand, the national security of supply will depend fundamentally on the evolution of the generation fleet in the whole region, which increases the uncertainties regarding the future evolution of the power system.
- Currently, Belgium has a strong national dependence on nuclear energy. However, the national energy policy envisages the total phase-out of the nuclear reactors by 2027 with an increase of RES installed capacity.

It is noted that all Figures shown in the following of sub-Chapter 5.2 are either direct copies from Elia's study or Figures that were translated by the authors of this report from the French original (non-official translation).

5.2.2 Scope

While the geographical coverage of the B_GA&FE is definitely much smaller than the ENTSO-E's MAF 2016, it could be suggested that its scope is broader. ENTSO-E's MAF 2016 aims to quantify the security of supply risks in a pan-European level, under a specific scenario on the evolution of the generation fleet and demand. Apart from assessing generation adequacy on a national level, Elia's B_GA&FE sets three additional goals (B_GA&FE, Section 2.3):

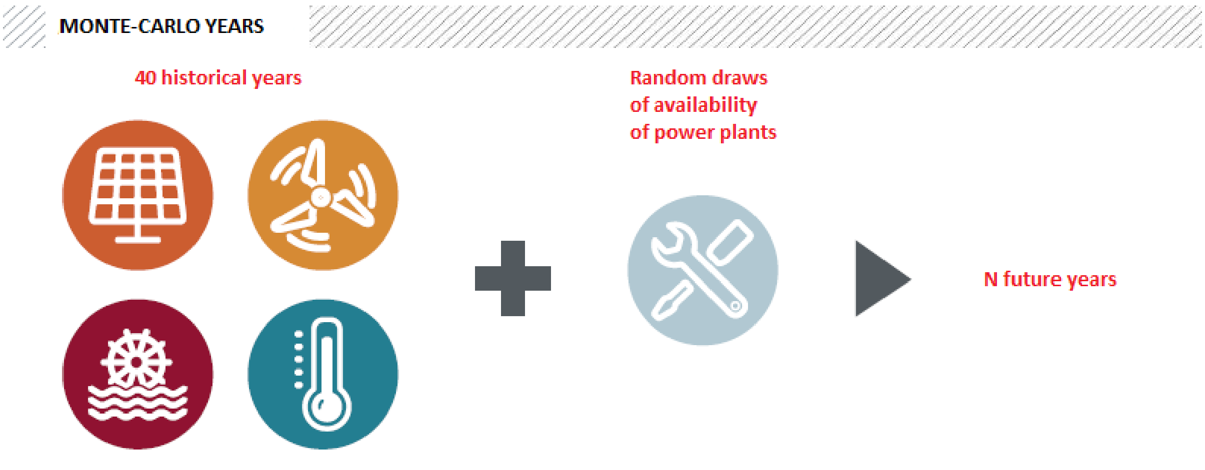
1. To assess the economic viability of the adjustable capacity required to meet the security of supply criteria, under an "Energy-only" market. This is a significant supplement to generation adequacy assessment in a deregulated market framework. However, it should be noted that the analysis covers only revenues from the Day Ahead market, while potential ones from ancillary services provision are not taken into account (B_GA&FE, p. 8).
2. To make an explicit assessment of the future flexibility requirements.
3. To discuss measures and market options in order to secure that the required adjustable capacity will be available in the future.

5.2.3 Methodology

In this Section, the main methodological points of the B_GA&FE study are summarised in order to put the flexibility requirements assessment into perspective. The latter will be discussed in more detail in the rest of sub-Chapter 5.2.

B_GA&FE follows a probabilistic chronological methodology (sequential Monte Carlo simulations), which is the same with ENTSO-E's MAF 2016. Correlated hourly climatic data on wind velocity, irradiance, temperature and monthly hydro conditions covering 40 years, along with the forced outage rates and the Mean Time to Repair of the thermal units are employed for generating the Monte Carlo years (B_GA&FE, Section 3.3) – see also Figure 14. A market model assuming perfect competition and foresight for the Day Ahead is developed covering the CWE Region along with its first neighbours, in total 19 countries. An NTC approach is followed for incorporating cross-border exchanges, while the conservative approach that no exchanges are made between the modelled area and the non-modelled countries is taken (B_GA&FE, Section 4.3). Finally, three target years are examined in detail (2021, 2023, and 2027) along with the current situation (2017), each one representing a major change in total interconnection capacity and/or national offshore wind and nuclear capacity (B_GA&FE, Section 3.1). In more detail, in 2021 the interconnections with Germany and Great Britain will have been constructed. The total offshore capacity envisaged for the future is installed, while the whole nuclear fleet is still present. In 2023, 2GW of nuclear capacity is decommissioned, while in 2027 the whole nuclear fleet will be phased-out. It is noted that the software tool employed is ANTARES.

Figure 14. Depiction of the Monte Carlo methodology employed by Elia



Source: Figure 7 of (B_GA&FE)

The major methodological difference between B_GA&FE and MAF 2016 is the differentiation in the former of the installed (and foreseen) generation capacity in two categories: The "structural block", which is the volume of adjustable national capacity required to cover the security of supply criteria, in accordance to the mandate given by the Belgian Federal Ministry of Energy, and the rest (B_GA&FE, Section 4.3). Namely, each examined Scenario considers a specific generation fleet and demand response volume that will be definitely available in the market (B_GA&FE, Section 4.1.7 and 4.1.8) – see Table 27. For each target year, the sequential Monte Carlo simulations provide the adequacy metrics starting with only this certain capacity. If the security of supply criteria are not met additional capacity is added in blocks of 500MW. This additional capacity constitutes the "structural block" (B_GA&FE, Section 3.3.2 and 3.3.3). It is noted that two adequacy criteria are employed: The average LOLE which should be less than 3 hours and the 95th percentile of LOLE should be less than 20 hours.

Table 27. Capacities not included in the "structural block" for the "Base Case" scenario (B_GA&FE, Fig. 35)

		2017	2021	2023	2027
Non intermittent	Cogeneration	1938	1938	1938	1938
	Nuclear	5926	5926	3912	0
	Pumped Hydro	1308	1308	1308	1308
	Biomass	1281	1881	1881	1881
	Total	**10453**	**11053**	**9639**	**5727**
Production dependent on climatic variables (intermittent)	Wind	2742	4847	5183	5854
	PV	3363	4013	4338	4988
	Hydro-RoR	114	114	114	114
	Total	**6219**	**8974**	**9635**	**10956**

Employment of the "structural block" approach permits a rather detailed analysis of the number of utilisation hours that each additional block of 500MW is expected to have in the future. This provides a basis for conducting an economic viability assessment of this additional capacity in an "energy-only" market. On the other hand, the definition of the "structural block" is somewhat unclear, a fact identified by the responses of the various stakeholders [23]. In general terms, the "structural block" could include any kind of generating technology (including RES) as well as demand response, storage and additional interconnection capacity (B_GA&FE, Section 3.2.2). In practice, the study considers only idealised gas units with 100% availability (no maintenance or forced outages) and enhanced flexibility performance (B_GA&FE, Section 3.4.3). The employment of only idealised gas units can be seen as a methodological artifice to facilitate the iterative process followed in the study.

The other main difference between B_GA&FE and MAF 2016 is the employment by the former of a range of sensitivity analyses (B_GA&FE, Section 4.5).

Table 28. Main assumptions in B_GA&FE (Fig. 43)

	Belgium	**CWE**	**Rest of the EU**	**Sensitivity**
Consumption	0% growth			0.6%/year
Renewables	Best estimation	National reports and bilateral contacts + SO&AF 2015	On the base of SO&AF 2015	High RES Scenario
Thermal capacity	Nuclear according to the law			"Coal Phase Out" and "Low Capacity" for the neighbouring countries
Demand Response	Pöyry study			Without Demand Response in Belgium
Storage	Actual pumped-hydro			With additional storage
Interconnections and import capacity	According to the federal development plan			+2GW import & Isolated Belgium
Balancing Reserves	Estimation in the study			
Fuel prices	The forward price for 2017 & IEA "Current policies"			IEA Scenario "450"
Fixed and variable costs of power stations	ETRI study of the European Commission			

5.2.4 Flexibility assessment - Residual Demand (concept)

Residual demand is a key concept of the flexibility requirements assessment in Elia's study. It is defined (B_GA&FE, Section 3.5.4) as the gross demand, before activation of any demand response, minus:

- the production by nuclear power plants,
- the RES injections (wind, solar and the run-of-the-river hydro units), and
- the "must run" units (biomass and cogeneration)

The estimation of the gross demand is based on extrapolation of historical data. The contribution of the dispersed generation is included, while the energy consumed by storage units is not. The latter, as well as the exports, are inherently calculated by the market model for each hour of each Monte Carlo year. When building the gross demand time-series for a Monte Carlo year its sensitivity to temperature is taken into account, but the impact of new technologies such as EV and heat pumps on the load profile are not (B_GA&FE, Section 4.1.6).

The Residual Demand concept inherently supposes that RES (or biomass and cogeneration units at that) do not regulate their power output, but are inflexible injections into the System. In this way the net flexibility requirements due to the variability of both demand and production is evaluated. Yet, the study acknowledges that these flexibility requirements could be covered by RES (and biomass and/or cogeneration plants), since in reality they could modulate their power output (B_GA&FE, Section 3.5.4).

It is noted that the actual behaviour of RES, biomass and cogeneration power plants is not governed only, or mostly, by their technical capabilities but also from regulatory arrangements, such as balance responsibility or not, valuation of ancillary services in the market, existence and type of financial support instruments to these technologies etc. This fact is clearly acknowledged in the conclusions of the Belgium flexibility requirements assessment (B_GA&FE, Section 6.3).

5.2.5 Sources of flexibility

In general, the study acknowledges the following sources of flexibility (B_GA&FE, Section 3.5.1):

- Adjustable generation such as gas units, but also to an extent RES (wind, solar), biomass, and cogeneration power plants
- Interconnections
- Demand Side Management (DSM)
- Storage units

Yet, the main goal of the study is to quantify the future flexibility needs as such, rather than examine an optimum mix of technologies to cover them. The latter is only discussed in a qualitative manner at the end of the study taking into account the current regulatory framework which defines to a significant extent the availability of the above resources to actually provide flexibility services.

5.2.6 Flexibility Needs

In Elia's study the following flexibility needs are identified:

1. The hourly variability of the residual load in the Day-Ahead horizon
2. The quarter-hourly variability of the residual load in the Day-Ahead horizon

3. Impact of forecast errors of wind and solar production as well as of the forecast error for the gross demand

4. The need for balancing reserves

The methodology for the sequential Monte Carlo simulations employed in the Elia's study –and in ENTSO-E's MAF 2016 at that- has two main limitations:

1. An hourly time-step is employed. Hence, intra-hour variability of the residual demand cannot be examined.

2. The assumption that all energy is traded in the Day-Ahead horizon with perfect foresight is made. Thus, the impact of forecast errors and the needs for balancing cannot be incorporated in a detailed manner.

As a consequence, only the hourly variability of the residual load is studied using the probabilistic chronological simulations. Quarter-hourly variability, forecast errors and balancing reserves are examined employing an extrapolation of the historic data of 2015 (B_GA&FE, Sections 3.5.5 and 3.5.6). The above will be elaborated in more detail in the following sub-sections.

5.2.6.1 Hourly variability of the residual load in the Day-Ahead horizon

Two analyses are conducted on the hourly variability of the residual load in the Day-Ahead horizon.

First, the mean residual load curve per examined target year is studied (B_GA&FE, Section 5.3.1). In this way the total volumes and respective hours of the required upward and downward flexibility are estimated per examined target year. This analysis provides effectively the number of hours per examined target year that a certain volume of upward and downward "capacity margin" should be available in the System.

Second, the hourly variability of the residual load and thus the hourly ramping capability that the System should be able to provide is studied. This is inherently done in the sequential Monte Carlo simulations of the Day-Ahead Market, since the technical constraints of generating units and Demand Side Management are modelled (ramp-up rates, minimum up and down times, minimum stable loading of generating units, available power and energy of Demand Response). In addition, an analytical probabilistic analysis of the residual load variability in an hourly and 3-hour resolution is made based on the employed climatic data of 40 years (B_GA&FE, Section 5.6.1).

5.2.6.2 Quarter-hourly variability of the residual load in the Day-Ahead horizon

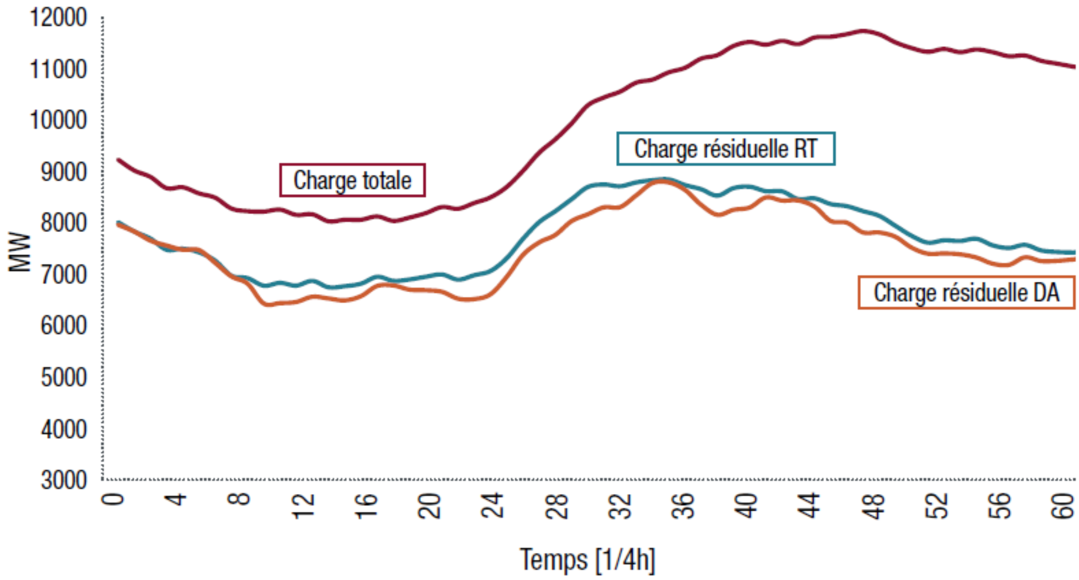
It is noted that the residual load variability (ramps) is analysed in the Day-Ahead horizon, not in real-time. Effectively, the estimation of the residual load in the Day-Ahead market is examined and not the residual load as such (see Figure 15). This is conducted employing a two-step process (B_GA&FE, Section 3.5.5, sub-section 2) – see also Figure 16:

1. First, the residual load with a quarter-hourly resolution is extrapolated based on the historic data of 2015 and the projections of installed capacity of RES and gross demand growth per Scenario and target year.

2. Second, the quarter-hourly forecast errors in the Day-Ahead horizon of gross demand, and RES production (wind and solar) are added. Again, an extrapolation on the historical data of 2015 regarding the day-ahead forecast errors is employed.

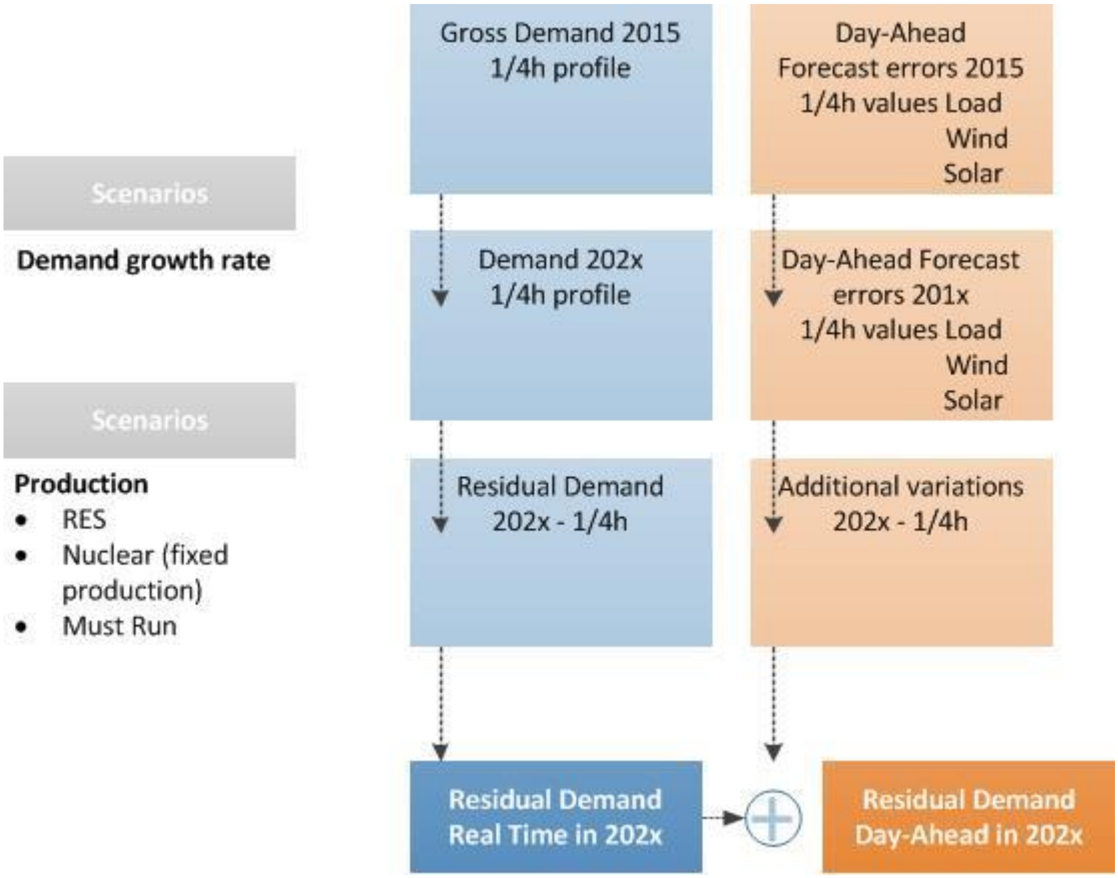
The respective flexibility requirements are assessed based on the density distribution function of the quarter-hourly variability of the residual load in the Day-Ahead horizon (B_GA&FE, Section 5.6.2).

Figure 15. Example of residual load profile in D-1 and in Real Time. Red: Total load. Blue: Real-time Residual load. Orange: Residual load in Day-Ahead



Source: Figure 23 of (B_GA&FE)

Figure 16. Process for constructing the Day-Ahead quarter-hourly profile of the residual load



Source: Figure 22 of (B_GA&FE)

5.2.6.3 Impact of forecast errors

The estimation of the quarter-hourly variability of the residual load in the Day-Ahead horizon incorporates also the variability of the respective forecast errors, but not the impact of these errors as such on the flexibility needs of the system (B_GA&FE, Section 3.5.5, sub-section 3). Hence, the density distribution function of the forecast error in the Day-Ahead horizon separately for the total RES production and the gross demand is also examined. Projections for the future are made based on the extrapolation of the historic data of 2015 described in the previous sub-section.

A drawback of the analysis, acknowledged by the study, is that simple extrapolation of the forecast errors for RES based on 2015 data provides somewhat pessimist results, since the attenuation of these errors resulting from the increased geographical dispersion of the RES units in the future is not taken into account (B_GA&FE, Section 5.6.3).

5.2.6.4 Balancing reserves (B_GA&FE, Section 3.5.6)

First of all, it should be noted that Elia's assessment examines the Reserve needs, which are not the same with the procured volumes of Reserves by the TSO, since synergies with other TSOs are possible for covering these needs (e.g. trans-national markets for FCR allocation, imbalance netting, Exchange and Sharing of Reserves etc.). In addition, BRPs inherently cover a part of the required Reserves in self-dispatched systems for balancing their portfolios.

Estimation of the balancing reserve needs in the future requires a coherent dimensioning methodology. This in Elia's study is different for FCR and FRR.

Dimensioning of FCR

The study does not follow the described methodology in the Commission Regulation on establishing a guideline on electricity transmission system operations (Article 153), henceforth referred to as the Regulation[14]. This necessitates a probabilistic dimensioning of FCR for the whole CE Synchronous Area in which Belgium is part of. Allocation of FCR obligation per TSO requires agreement between them in a Synchronous Area level. Still the Regulation sets an initial allocation principle based on the net position of each TSO's responsibility region (LFC block) in respect to the total net position of the Synchronous Area.

Summarising, implementation of the Regulation on FCR dimensioning necessitates future inter-TSO coordination. Given the uncertainties that this employs for the future, Elia makes the assumption that its FCR obligation allotment will remain the same as a percentage leading to an absolute increase.

Dimensioning of FRR

The methodology followed is based to a significant extent on the provisions of the Regulation on dimensioning of FRR (Article 157). In this case this is possible, since FRR requirements in the latter are defined per LFC block.

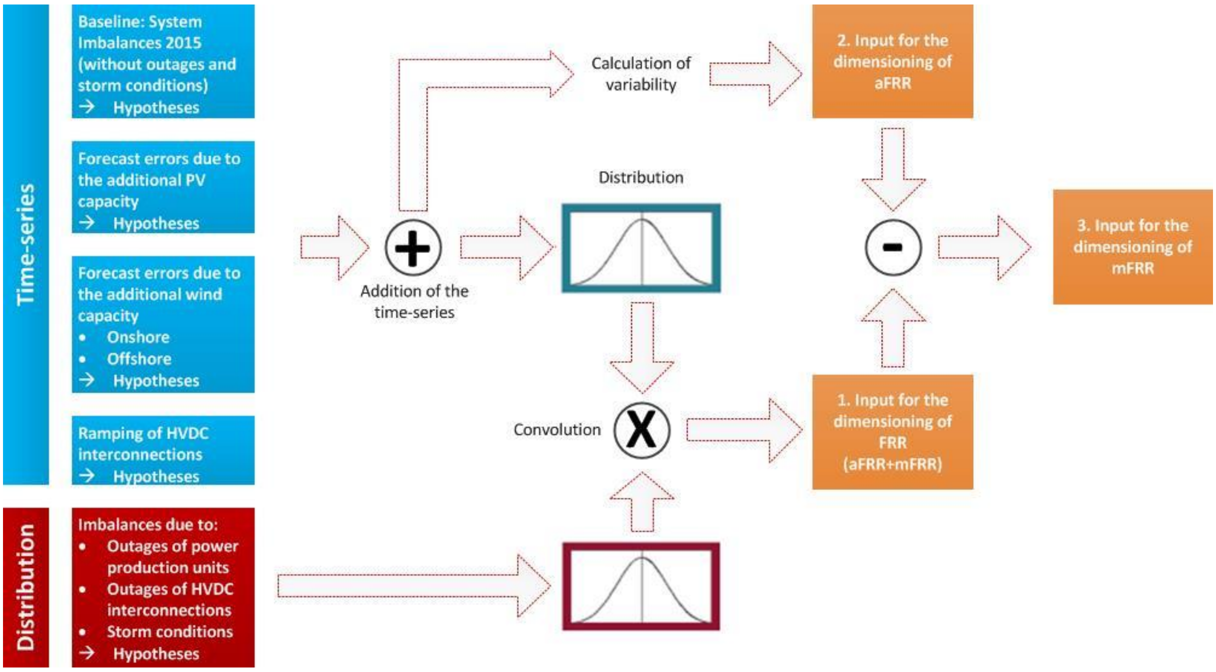
The FRR volume in each direction should at least cover the positive and negative Reference incident. In addition it should cover the imbalances caused by forecast errors and market schedules (ramping of HVDC injections at the beginning of each hour). Overall, a probabilistic methodology should be employed based on historical imbalance data. The minimum volumes of required FRR in each direction should cover the imbalances for at least 99% of the examined time.

In Elia's adequacy and flexibility requirements study the following steps are made to assess the future needs in FRR (Figure 17):

[14] When these lines are written, the Commission Regulation on establishing a guideline on electricity transmission system operations has already been validated by the Member States and is expecting validation by the European Parliament and Council. The Regulation is the product of merging the former network codes on Operational Planning and Scheduling (NC OPS), Operational Security (NC OS) and Load Frequency Control and Reserve (NC LFCR).

1. The probability density function of imbalances caused by the loss of generating units, HVDC interconnectors and storm conditions which may lead to the shut-down of offshore wind farms is constructed. In this step, imbalances caused by forced outages of system components are evaluated.
2. Based on the historical records of system imbalances in 2015, from which imbalances caused by forced outages and storm conditions are excluded, the extrapolated time-series of the future forecast errors due to the additional PV and wind capacities as well as the imbalances due to ramping of new HVDC interconnections are added. From the final summed time-series the probability distribution function of the imbalances attributed to these causes is constructed. In this step, imbalances caused by the variability of net injections and withdrawals in the system are evaluated.
3. In parallel, from the time-series of imbalances constructed in the previous step the quarter-hourly variability (ramping) of these imbalances is calculated.
4. The two constructed probability distribution functions, one relating to forced outages and one relating to generation and load variability, are convoluted. The produced density probability function defines the required FRR volumes. Specifically, in the study positive FRR is dimensioned to cover 99.9% of negative imbalances, and negative FRR is dimensioned to cover 99% of positive imbalances.
5. Differentiation is made between aFRR and mFRR. aFRR is dimensioned to address the ramping of imbalances due to generation and load variability (step 3). mFRR is calculated as the difference between the total FRR and the aFRR volumes.

Figure 17. Methodology for the dimensioning of balancing reserves



Source: Figure 25 of (B_GA&FE)

5.2.7 Results

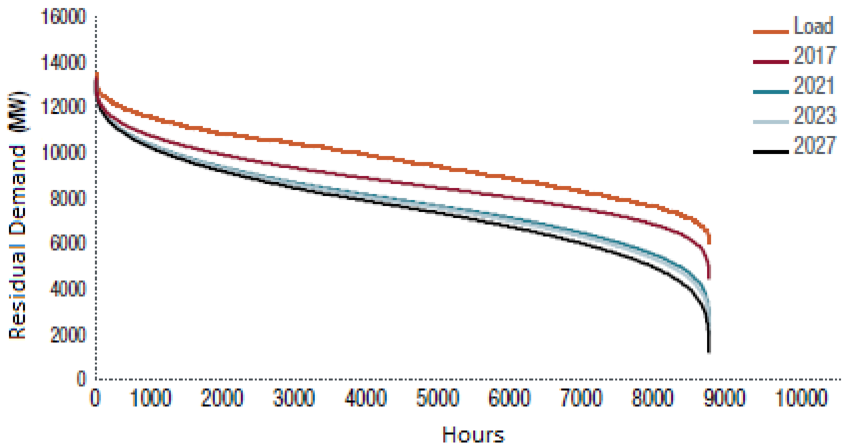
In this Section the results only regarding the flexibility assessment are presented in more detail. The full analysis can be found in Sections 5.6 and 6.3 of Elia's study.

5.2.7.1 Hourly variability of the residual load in the Day-Ahead horizon

Figure 18 and Figure 19 depict the mean residual load curve for the examined target years. The following conclusions have been deduced (B_GA&FE, Section 5.3.1):

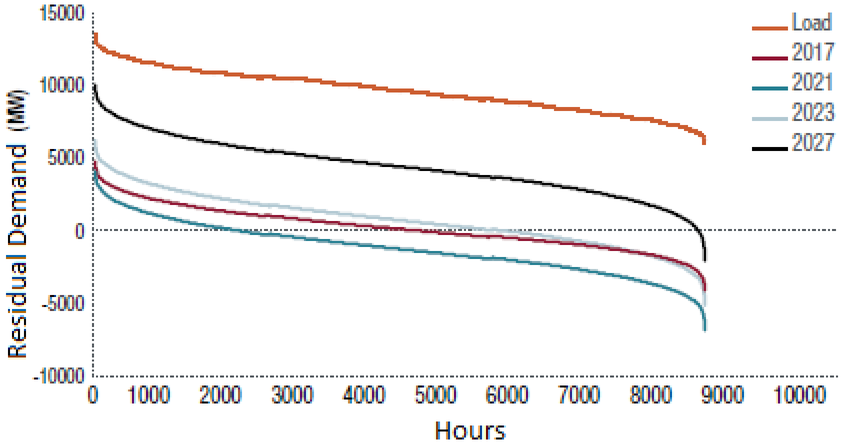
1. Intermittent renewable sources have little contribution under conditions of peak demand, which in Belgium are encountered in winter during very cold days. Under these climatic conditions there is absence of sun and weak wind conditions.
2. Off-peak residual load drops significantly from 2021 onwards as a result of the new offshore wind capacity.
3. There will be increasing need for exports and/or storage in the future given also the inflexibility of nuclear generation and the "must run" status of cogeneration and biomass power plants.

Figure 18. Load curve of the residual demand calculated as: Demand-Wind-PV-RoR Hydro for Belgium



Source: Figure 54 of (B_GA&FE)

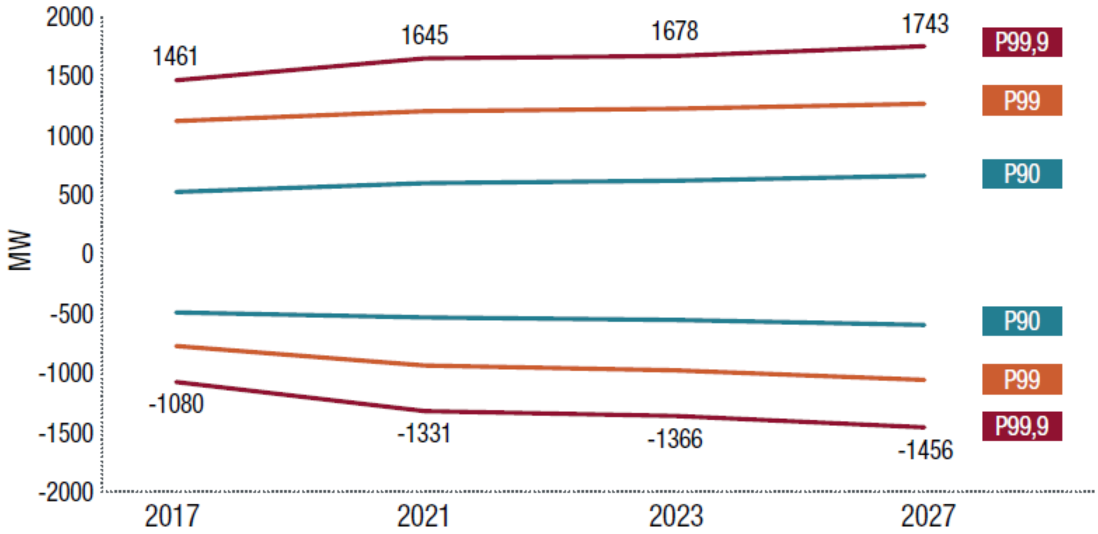
Figure 19. Load curve of the residual demand calculated as: Demand-Wind-PV-RoR Hydro-Nuclear-Cogeneration-Biomass for Belgium



Source: Figure 55 of (B_GA&FE)

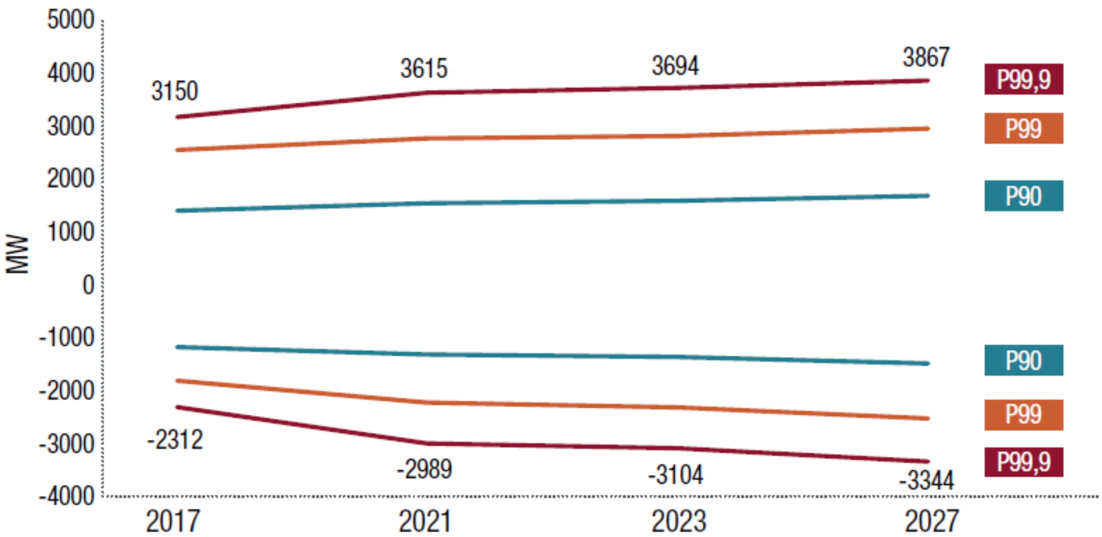
Figure 20 and Figure 21 depict the percentiles of the hourly and 3-hour residual load ramps respectively. Residual load ramp rates increase mainly between 2017 and 2021 as a result of the new offshore capacity. The analysis showed that large hourly ramp rates are recorded during morning when demand increases. 3-hour ramp rates are also expected at dusk as a result of the "duck curve" effect of PV systems – see also (B_GA&FE, Section 3.5.5).

Figure 20. Necessary hourly flexibility for covering the Belgic residual demand (analysis on 40 climatic years)



Source: Figure 79 of (B_GA&FE)

Figure 21. Necessary 3-hour flexibility for covering the Belgic residual demand (analysis on 40 climatic years)

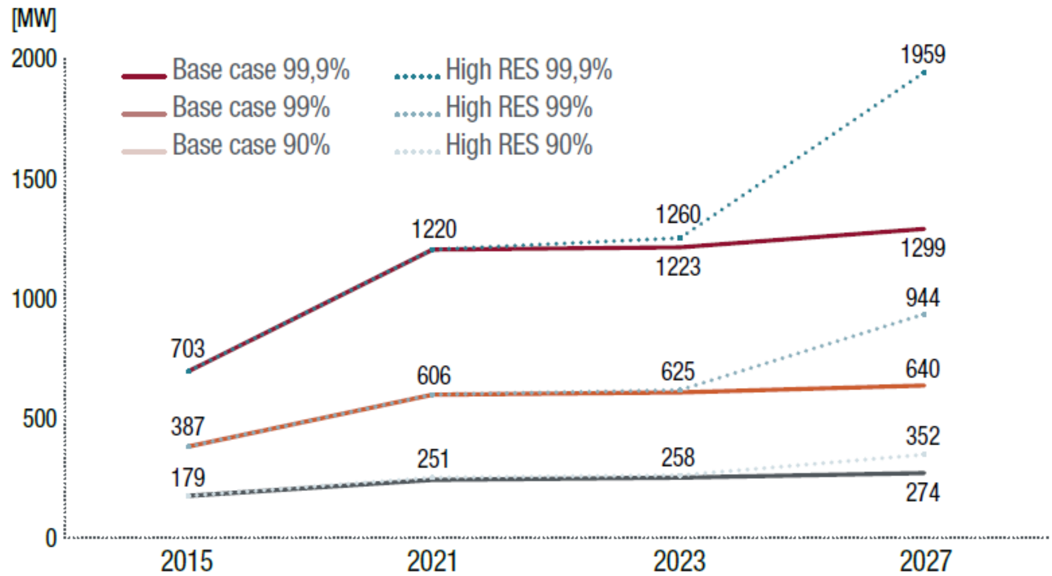


Source: Figure 80 of (B_GA&FE)

5.2.7.2 Quarter-hourly variability of the residual load in the Day-Ahead horizon

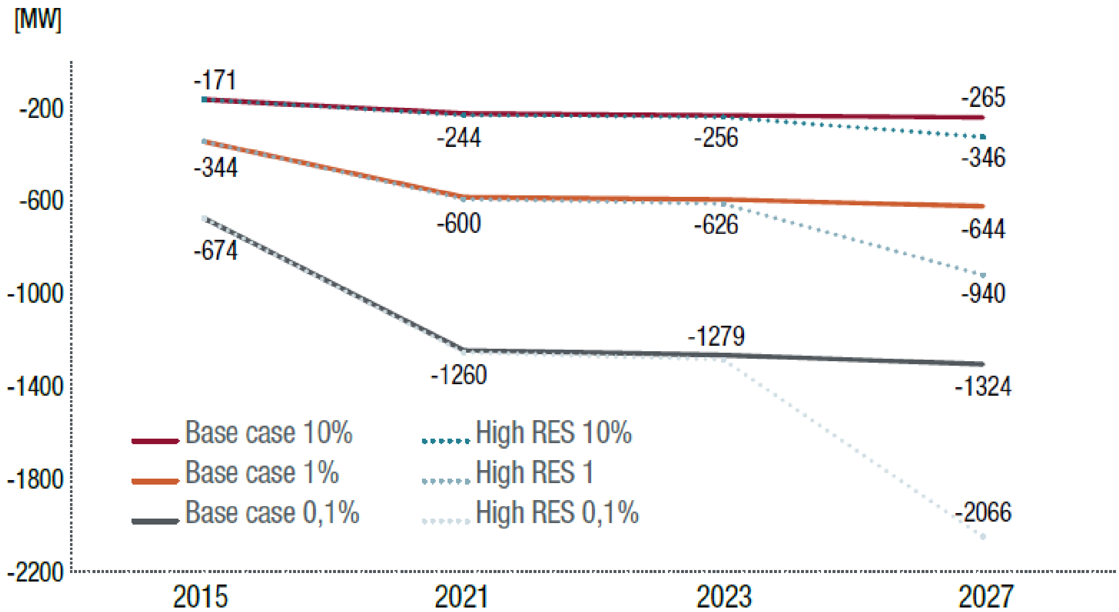
Figure 22 and Figure 23 summarise the results of the analysis. For the "Base Case" Scenario the quarter-hourly variability requirements increase significantly from 2015 to 2021 and little henceforth. For the "High RES" Scenario there is an additional jump in 2027. In both cases the rise of quarter-hourly variability is due to new offshore wind capacity.

Figure 22. Percentiles of positive quarter-hourly residual demand variability per Scenario



Source: Figure 83 of (B_GA&FE)

Figure 23. Percentiles of negative quarter-hourly residual demand variability per Scenario



Source: Figure 84 of (B_GA&FE)

5.2.7.3 Impact of forecast errors

Figure 24 depicts the results of the analysis on the expected RES forecast errors. As expected, with increasing installed RES capacity the forecast error also increases in absolute values. Yet it is noted that the attenuation of forecast error resulting from larger geographical dispersion of the RES plant has not be fully taken into account making the results somewhat pessimistic.

Large forecast errors on RES production (greater than 1GW) are only expected for 1% of the time in the future. Except from the "High RES" Scenario in 2027, the respective error is less than 500MW for 90% of the time.

Finally, the analysis showed that in the Day-Ahead horizon, RES production is over-estimated while demand is under-estimated, both leading to an increased requirement for upward flexibility.

Figure 24. T RES Forecast error [MW]

Time horizon		Percentile				
		99%	90%	10%	1%	0,1%
		Base Case				
2015	984	575	252	-200	-501	-883
2021	2110	1180	520	-434	-942	-1443
2023	2177	1230	551	-453	-999	-1508
2027	2321	1338	611	-491	-1102	-1685
		'High RES'				
2015	984	575	252	-200	-501	-883
2021	2127	1193	529	-439	-956	-1449
2023	2227	1277	572	-467	-1033	-1560
2027	3579	1955	861	-712	-1561	-2406

Source: Page 71 of (B_GA&FE)

5.2.7.4 Balancing reserves

FCR needs are estimated to rise from 73MW currently to 80-100MW in the future. Still, one should keep in mind the uncertainties mentioned in sub-section 5.2.6.4 regarding the dimensioning of FCR.

The needs for negative mFRR augments significantly due to the increase of the Dimensioning Incident (loss of the HVDC interconnection to the UK when exporting energy) and the increase in the forecast errors of the RES power production.

The needs for positive mFRR also increase due to the rise of RES forecast errors and as a result of the risk of losing the offshore wind production under storm conditions. In the latter risk, a contributing factor is the geographical concentration of the Belgian offshore wind farms.

The needs for aFRR rise due to the increased quarter-hour variability that the Belgian Power System is expected to experience.

The results are summarised in Figure 25.

Figure 25. Results on Balancing Reserves needs

BALANCING RESERVES NEEDS

Time horizon	FCR	FRR+	aFRR+	mFRR+	FRR-	aFRR-	mFRR-
2016	73	910	140	770	140	140	-
Base Case							
2027	80-100	1240	175	1065	1000	175	825
2023	80-100	1240	175	1065	1000	175	825
2021	80-100	1240	175	1065	1000	175	825
'High RES'							
2027	80-100	1800	190	1610	1190	190	1000
2023	80-100	1240	175	1065	1000	175	825
2021	80-100	1240	175	1065	1000	175	825

Source: Page 72 of (B_GA&FE)

5.2.7.5 Discussion and overall conclusions

The most significant outcome of the flexibility assessment is the need for 2-4 "structural block" CCGT units of 1500MW total in both 2021 and 2023 for covering the requirements for aFRR, which in the context of the Belgian study is related to the management of the quarter-hourly variability (B_GA&FE, Section 5.5.1). It is noted that the adequacy study as such, which also covers through the sequential Monte Carlo simulations hourly variability flexibility needs, showed that no adjustable "structural block" capacity is needed for covering demand in 2021 and only 500MW is required for 2023.

The outcome depends on a number of factors (B_GA&FE, Section 6.3):

- Reserves in the Belgian adequacy and flexibility assessment are quantified in a yearly basis. Dimensioning and procurement of reserves in a daily basis could be a necessary step in the future.
- Potential fusion of LFC blocks in Europe would alter both the calculated needs for Reserves, but also the potential resources.
- Current financial support schemes on RES, biomass and cogeneration actually provide a negative incentive to them for offering balancing reserves
- Under the current market structure, the availability of reserve provision by pumped-hydro and interconnections is rather limited. The business case for the former is based on time arbitrage between hours of low residual load to hours of high demand, while interconnection capacity is mostly utilised in the Day-Ahead market.

5.2.8 Remarks

The adequacy and flexibility study of Elia shares many similarities with ENTSO-E's MAF 2016 methodology, but it also addresses the following two key issues:

- An assessment of the economic viability of current and future capacity required for security of supply
- An explicit assessment of the flexibility requirements of the Belgian power system

The two issues are interlinked in fact under the followed methodology, at least for the hourly variability flexibility needs that are studied based on the sequential Monte Carlo market simulations. Incorporating assessment of flexibility needs into the ENTSO-E's MAF 2016 probabilistic chronological methodology is a significant step forward.

The employment of an analytical probabilistic methodology, based on extrapolations on historical data, can provide hindsight for evaluating the flexibility needs resulting from the quarter-hourly variability of the residual load and the forecast errors. However, an overall coherent methodology would require evaluation of these flexibility needs to be also incorporated into the sequential Monte Carlo simulations. Such a step forward would require modelling of the intraday and the balancing markets, a goal already identified by the ENTSO-E in MAF 2016. Modelling of these two markets in addition to the Day-Ahead would also permit to quantify the impact of reserves dimensioning and level of provision on the expected LOLE in a thorough manner.

Finally, one of the strong points of Elia's study is the discussion on possible regulatory directions for uncapping the potential of certain flexibility resources such as renewables (B_GA&FE, Section 6.3). Yet, one should keep in mind that currently it is not on the mandate of TSOs to decide or to investigate in detail by their own initiative such regulatory options. Hence, TSOs, and this is the case for Elia also in the discussed study, have to conduct their flexibility assessments given the current regulatory framework, a fact defining to a significant extent the methodological decisions made.

5.3 ADMIE flexibility assessment review

5.3.1 Introduction

In December 2016, ADMIE published an investigation on flexibility needs [12], henceforth referred to as G_FE, after a request by RAE as an addendum to the generation adequacy assessment published in June of the same year.

It is noted that all Tables shown in the following sub-Sections are (non-official) translations from the Greek original.

5.3.2 Scope

The scope of the study is an investigation and quantification of the flexibility needs of the Greek Power System for every year between 2017 and 2023.

5.3.3 Methodology

The study is based on an analytical probabilistic analysis of the residual demand time-series in the future. The latter are constructed based on an extrapolation of historical data. Sensitivity analysis is made on the basis of the different Scenarios examined in the main body of ADMIE's generation adequacy study.

5.3.4 Flexibility assessment - Residual Demand

The Residual Demand is a key concept of the flexibility requirements assessment in ADMIE's study. It is defined as the gross demand, before activation of any demand response, minus (G_FE, Sections 2 and 3.2.2):

- The RES power production
- The power production of the mandatory hydro
- The totality of the other injections with dispatch priority (namely the injection by the Cogeneration plant of Aluminium of Greece)

The estimation of the gross demand is based on extrapolation of historical data and the demand growth Scenarios (low, base case and high) defined in the main body of ADMIE's generation adequacy study (Section, 6.3, Table 6.2). According to the latter, both the annual energy demand and the peak load are taken into account in constructing the future gross demand time-series, but no details are provided on the exact procedure followed.

RES production time-series for the future years are calculated by an extrapolation of the historical data of 2014 according to the capacities foreseen in the main body of the generation adequacy study (Table 4.9).

Cogeneration power production follows the same behaviour with the one showed in 2014.

For the mandatory hydro injections an extrapolation technique was not employed, since recent regulatory decisions have changed significantly their behaviour in the market. Hence, ADMIE built time-series for the future based on November's 2016 12-month declaration of mandatory hydro injections and assuming a peak shaving behaviour (G_FE, Section 3.3.1).

5.3.5 Sources of flexibility

The goal of the study is to quantify the future flexibility needs as such, not to examine an optimum mix of technologies to cover them. Only in Section 2, page 4, first paragraph of ADMIE's flexibility assessment study there is a more specific remark on potential flexibility sources, namely:

- Conventional thermal and hydro units
- Interconnections
- Demand Side Management

One should note the absence of RES and storage units as potential flexibility resources.

5.3.6 Flexibility Needs

In ADMIE's study the following flexibility needs are identified (G_FE, Section 2):

1. The needs for flexible capacity
2. The hourly and 3-hour variability of the residual load
3. Forecast errors
4. The need for balancing reserves

As discussed previously, in all cases an analytical probabilistic analysis is conducted for the quantification of the future flexibility needs, based on extrapolation of historical data. The analysis covers first the period 2013-2016, mainly for calculating the probability distribution function of the forecast errors, and then each year between 2017 and 2023.

The above will be elaborated in more detail in the following sub-sections.

5.3.6.1 Needs for flexible capacity

The duration curve of the residual load for each examined year and demand growth Scenario is studied.

As discussed previously, a similar analysis has been made also in Elia's study, to which a specific reference is made in ADMIE's flexibility study. However, in contrast to the former where the mean duration curve of the residual load based on 40 climatic years was analysed, in ADMIE's study a single residual load time-series is constructed per examined year and Scenario.

5.3.6.2 Hourly and 3-hour variability of the residual load

The hourly variability of the residual load and thus the hourly ramping capability that the System should be able to provide is studied based on an analytical probabilistic analysis. Again, a single residual load time-series is examined per year and Scenario. It is noted that the final product of the analysis is a probability distribution function of the hourly (and one for the 3-hour) residual load variability which takes into account all three examined Scenarios on demand growth.

5.3.6.3 Forecast errors

Only the forecast error of the hourly System Load in the Day-Ahead horizon is examined. This incorporates the forecast errors for both the gross demand and the distributed RES generation, but not the forecast error of the transmission system RES. The latter is not examined at all (G_FE, Sections 2 and 3.1.4).

Only a historic evaluation is conducted for the period January 2013-September 2016. Instead of an empirical probability distribution function a fitted two-piece normal distribution function is employed for describing the examined forecast error.

No projections into the future are made. In fact, it is considered that the probability distribution function of the forecast error of the System Load will remain the same (G_FE, Sections 2, p. 5, footnote 5). One could suggest that this is a rather big assumption given that the RES distributed generation capacity, such as PV, will increase in the future as envisioned also in the main body of ADMIE's generation adequacy study (Section 4.4.2 of the latter). More importantly, it is the residual's load, not the System's load, forecast error that defines the flexibility needs, but evaluation of this would necessitate a detailed evaluation of the forecast error of all RES (both distribution and transmission connected).

5.3.6.4 Balancing reserves

Even though, forecast error and variability of gross demand and RES as well as forced outages of System components are identified as the main causes for needing flexibility (G_FE, Sections 2, third paragraph), there is no assessment of balancing reserve needs in the study.

In Section 2, last paragraph of ADMIE's flexibility study it is asserted that secondary reserves (i.e. FRR according to the Regulation on System Operations terminology) are dimensioned to cover the Reference Incident. It should be noted that this dimensioning principle is not in full compliance with the Regulation's provisions. Moreover, information on the dimensioning rules employed for FCR and on the differentiation of FRR between aFRR and mFRR is not provided at all.

5.3.7 Results

It is noted that the discussion on the results of the analysis is minimal in ADMIE's flexibility assessment. Thus, following a graphic presentation of some of the outcomes will be presented. The full results can be found in Section 3 of the study.

5.3.7.1 Needs for flexibility

Table 29 presents the main characteristics of the duration curves of the residual demand for the examined future years and Scenarios.

Table 29. Characteristics of residual load duration curves for the period 2017-2023 (G_FE, Table 3.5)

	2017	2018	2019	2020	2021	2022	2023
Scenario of base case demand growth							
Maximum (MW)	7582	7735	7839	7920	8002	8063	8121
Minimum (MW)	1006	952	874	784	709	627	542
Energy (GWh)	38700	39094	39212	39207	39253	39209	39175
Scenario of high demand growth							
Maximum (MW)	7632	7828	8003	8155	8269	8377	8486

Minimum (MW)	1029	995	949	891	833	771	710
Energy (GWh)	38995	39624	40132	40522	40793	40994	41205
Scenario of low demand growth							
Maximum (MW)	7531	7640	7679	7695	7734	7754	7773
Minimum (MW)	982	909	799	678	584	483	382
Energy (GWh)	38415	38574	38302	37922	37743	37474	37205

5.3.7.2 Hourly and 3-hour variability of the residual load

Table 30 and Table 31 present the expected percentiles of the hourly and 3-hour variability of the residual load respectively in the future. It should be noted that comparing the results of the historic analysis for the period 2013-2016 (G_FE, Section 3.1.2) and the expected variability of the residual demand shown below, a sudden step increase occurs at year 2017. For instance, the maximum 99.99th percentile of hourly and 3-hour residual load ramp in the past period examined was 909MW (recorded in 2015) and 2022MW (recorded in 2014) respectively. In 2017 the respective quantities are 1198MW and 2793MW, i.e. an increase of 31.8% and 38.1% respectively is expected. No information is provided in ADMIE's flexibility assessment study for this expected step rise in residual demand variability at 2017.

Table 30. Maximum and minimum value of the Hourly Variability of the Residual Load in the period 2017-2023 for typical confidence intervals (G_FE, Table 3.7)

Probability (%)	2017	2018	2019	2020	2021	2022	2023
99.99	1198	1232	1263	1293	1320	1346	1372
99.7	896	922	945	967	987	1007	1026
95	530	545	559	572	584	595	607
5	-484	-497	-509	-519	-529	-538	-547
0.3	-818	-840	-860	-878	-894	-910	-925
0.01	-1094	-1123	-1150	-1174	-1195	-1216	-1237

Table 31. Maximum and minimum value of the 3-Hour Variability of the Residual Load in the period 2017-2023 for typical confidence intervals (G_FE, Table 3.9)

Probability (%)	2017	2018	2019	2020	2021	2022	2023
99.99	2793	2881	2962	3037	3107	3174	3242
99.7	2089	2155	2216	2272	2324	2375	2425
95	1235	1274	1310	1343	1374	1404	1434
5	-1150	-1184	-1214	-1241	-1265	-1288	-1311
0.3	-1945	-2002	-2053	-2099	-2139	-2178	-2217
0.01	-2600	-2677	-2744	-2805	-2860	-2911	-2963

5.3.7.3 Forecast errors

As discussed in Section 5.3.6.3 of the present report, only the forecast error covering the period January 2013-September 2016 and only for the System Demand has been examined in ADMIE's flexibility assessment study. The main results are summarised in Table 32.

Table 32. Maximum forecast error of System's Load for typical confidence intervals (G_FE, Table 3.4)

Probability (%)	Maximum hourly error (MW)
99.99	815
99.7	609
95	360
5	-419
0.3	-709
0.01	-947

5.3.7.4 Discussion and overall conclusions

In the relevant Section 4 of ADMIE's flexibility assessment only a short resume of the work implemented is made without any discussion and/or conclusions on the flexibility challenges that the Greek Power System could encounter in the future and some first directions on their resolution.

5.3.8 Remarks

ADMIE's flexibility assessment study is based on an analytical probabilistic analysis which is based on extrapolated historical data. One could suggest that there is significant room for improvements especially in the following fields:

- The forecasted ramping requirements show a step increase in 2017 compared to 2016 levels. It may be worthwhile investigating if this is related to an expected System change or if it is caused by the time series used in the forecast.
- Examination of the flexibility needs due to the intra-hour variability of the residual load. This may have a significant impact on the future needs for aFRR.
- Examination of the impact of different climatic conditions on the flexibility needs of the Greek power system respective to the hourly and 3-hour residual load variability.
- Examination of the expected (future) RES forecast errors. Given that the larger penetrations of RES in the future will probably increase forecast errors and respective flexibility needs, this is quite a matter of importance.
- Analysis on the future balancing reserve requirements. It is noted that balancing reserves is the main means to address flexibility requirements in a power system. Hence, quantification of the future necessities in them could be considered as the natural final outcome of any flexibility analysis.
- A qualitative and quantitative analysis should identify how the future balancing reserve requirements identified previously will be served. (Which are the potential resources that are expected to be available to provide the reserves? Will they be adequate? What needs to be done if not).

Finally, the absence of a technical discussion on the results of the analysis already made and of their implications on the long-term planning of the Greek power system is a rather obvious weakness of the study.

5.4 Comparison of flexibility assessment methodologies

5.4.1 Introduction

In this sub-Chapter a comparison between the flexibility requirements assessment studies of ADMIE and Elia is conducted, with the latter considered as a benchmark. The latter choice is taken since ADMIE's study aims to follow the methodology undertaken by Elia (G_FE, Section 1).

5.4.2 Methodology and examined flexibility requirements

Both studies examine annual flexible capacity needs, hourly and 3-hour residual demand variability. However, there are two main differences between the studies:

1. In the Belgian case, the future capability of the power system to cope with hourly and 3-hour residual demand variability is first examined inherently by the market simulations and second by an analytical probabilistic analysis. In the Greek case, ADMIE employs just the second approach.
2. In the analytical probabilistic analysis of Elia, the impact of different climatic conditions is considered, since the analysis is implemented taking into account the data of 40 different climatic years in respect to wind, irradiance, temperature and hydro inflow conditions. In contrast, ADMIE's methodology to forecast ramping requirements employs an extrapolation on one year's data.

Quantification of forecast errors is another common subject of interest in the two studies. Yet again, the differences are significant:

1. Elia examines the forecast error for gross demand, and RES output separately and thus also of the residual load. ADMIE studies the forecast error of the system demand, which does incorporate the forecast error of distributed generation, but not the one of transmission connected RES power plants. The value of such investigation is debatable, since it is the forecast error of the Residual Demand as a whole, incorporating both gross demand and RES output in total – both in distribution and transmission level - which impacts a Power System's flexibility needs, such as the necessary volume of operational balancing reserves.
2. Elia conducts projections of the probability distribution function of the forecast error in the future. ADMIE makes only a historical analysis with no connection to the expected future conditions, and respective needs.

Finally, Elia examines two more issues which are completely absent in ADMIE's study:

1. Future quarter-hourly flexibility needs
2. Balancing Reserves future needs

It is noted that it is due to these requirements, specifically the enlarged needs for aFRR resulting from increased quarter-hourly residual demand variability, that the need for additional flexibility resources in the mid-term is founded in Elia's study.

Other differences between the two studies include the employment of more sensitivity scenarios in the Belgian case, larger examined time horizon (from 2017 to 2027, i.e. 4 years further in the future than in the Greek case), but lower chronological granularity (4 specific years are examined in Elia's study, while every year in the period 2017-2023 is analysed by ADMIE).

5.4.3 Residual Demand

The two studies agree on the definition of the key concept of Residual Demand. However, a short note should be made in the calculation of hydro injections in ADMIE's study. Hydro volumes that are not mandatory are actually a source of flexibility, i.e. they belong to the adjustable units, and should not be taken into account in the calculation of the residual demand. In contrast, ADMIE effectively predefines a specific operation of the hydro units (peak-shaving) as mandatory (G_FE Section 3.2.1, last paragraph). It is noted that the issue pertains to the regulatory framework concerning the operation of hydro units and the definition of mandatory hydro injections.

5.4.4 Sources of flexibility

In contrast to Elia's study, ADMIE does not provide an assessment of the providers of flexibility.

5.4.5 Conclusions

The two studies seek to address questions on system adequacy and security for two similar in terms of size, but different in terms of structure, systems.

The Belgian TSO operates a highly interconnected system which in terms of adequacy, will require gradually reduced presence of units technically suitable to provide aFRR (CCGTs) during the period 2018-2021 with effectively minimal requirements thereon until 2024, the last year of operation of the nuclear units.

The Greek TSO operates a significantly less interconnected system which, in terms of adequacy, requires significant presence of CCGTs, lignite-fired steam plants and hydro throughout the study's horizon. The sensitivity analysis by ADMIE on the effect of the withdrawal from the market of two CCGTs indicates that at least 4.2 GW (4,6 in 2019) of CCGTs and 3,3 GW of Hydro and 3,9 GW of lignite-fired steam plants are required in order to meet reliability standards.

Even though ADMIE's study makes a specific reference to the Elia's methodology for flexibility requirements assessment, there are significant differences between them.

First, in ADMIE's study, not all flexibility requirements identified in Elia's study are examined. Of particular importance is the lack of an analysis on future balancing reserve needs.

The Belgian TSO's flexibility analysis aims to quantify the balancing requirements (FCR, aFRR & mFRR) of the system until 2027 by using probabilistic analysis of D-1 forecast errors, for demand, wind and solar generation, residual load variability, as well as resource outages.

The addendum to the Greek TSO's adequacy study focuses on a similar issue but it is more simplistic in terms of probabilistic analysis (there is no convolution of probability density functions). Also the most important difference of the study by ADMIE is that it does not appear to address a specific question with relevance to system operation, since it does not lead to the quantification of future requirements in terms of FCR, aFRR and mFRR.

Furthermore, in contrast to the study by Elia, in the study by ADMIE no coherent discussion is made on the outcomes of the flexibility assessment analysis and their relation to the long-term planning process of the Greek Power System.

Table **33** provides a comparative overview of the two studies.

Table 33. Comparison of flexibility methodologies of ADMIE and Elia

	Elia	ADMIE
Residual load definition	Total load – RES – Nuclear – RoR Hydro - Cogeneration	Total load – RES – mandatory hydro
Ramping requirements based on residual load variability	Forecast 2017-2023 Based on statistical analysis of multiple years	Historical data 2013-2016 & forecast by extrapolating one-year time series 2017-2023
Time step	1 hour & 15 min	3 hours & 1 hour
Methodology to calculate reserve requirements	Based on probabilistic analysis (convolution probability distributions) of: - D-1 demand forecasting errors - D-1 wind & solar forecasting errors -residual demand variability - events (outages, storms etc.)	Not provided
Quantification of reserve requirements	Yes 80-100MW FCR 175 MW aFRR	No
Analysis of the supply situation of balancing & reserves	Yes. Descriptive And quantitative: 2-4 CCGTs required to provide 2ndary reserve (aFFR) considering maintenance requirements.	No.

5.5 Flexibility Assessment in the USA – an example

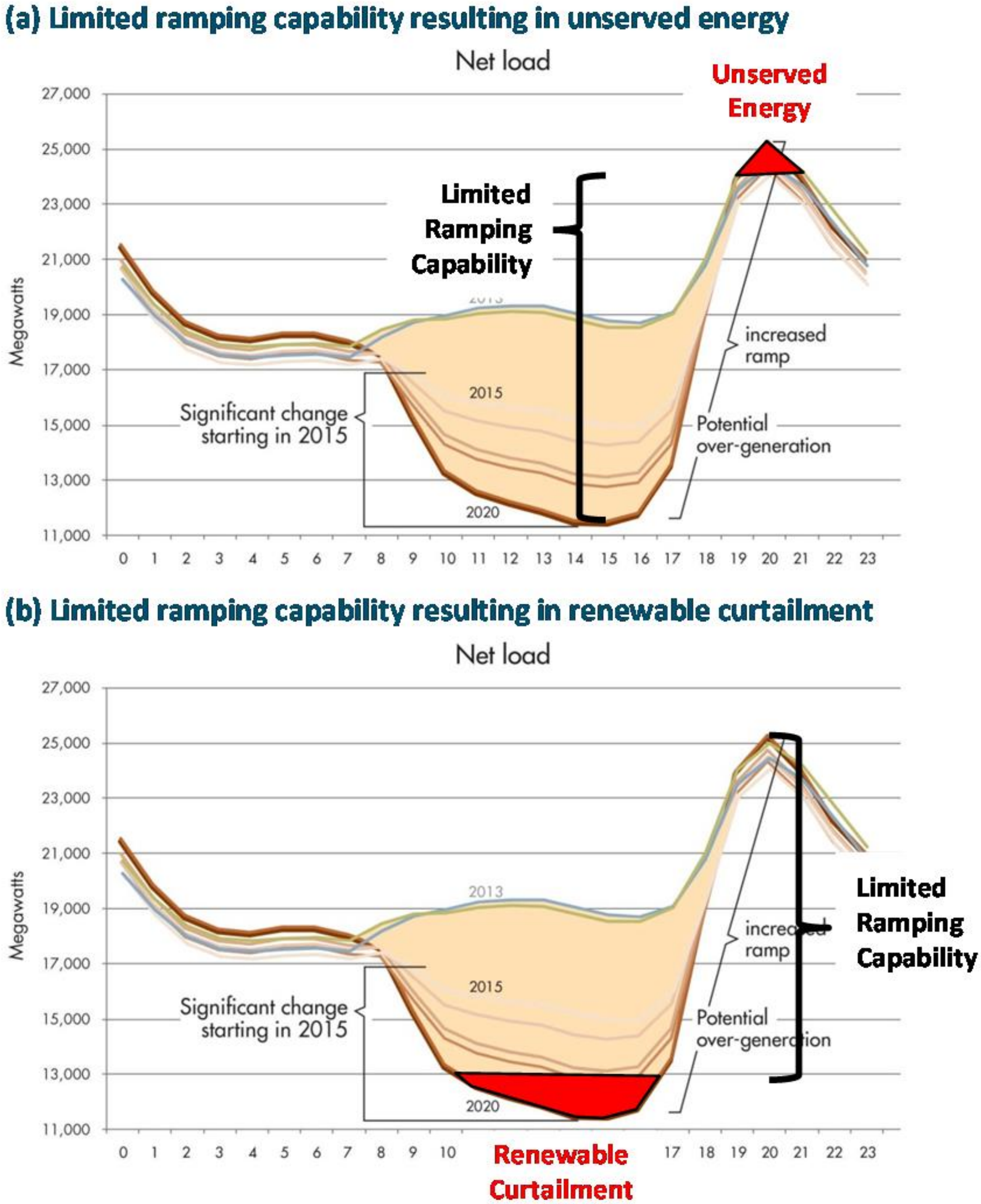
As already mentioned in this report, flexibility needs assessment is an ongoing field of investigation. In this respect, along with the Elia study representing the most advanced methodology in European level, the Western Interconnection Flexibility Assessment [18] by NREL deserves a short presentation. The study covers both the issues of generation adequacy and flexibility assessment. Following, the latter will be discussed in more detail.

The Western Interconnection Flexibility Assessment, henceforth referred to as WIFA, employs a market model but without using sequential Monte Carlo simulations covering a whole year, as in the case of Elia. Instead each Monte Carlo draw covers just one day, as a trade-off between assessing the impact of different climatic and availability conditions on the one hand, and reducing computational effort on the other. However, the WEFI study introduces some significant new elements:

- For each examined day, both the Day-Ahead market dispatch and the hour-ahead (considered as "real-time") dispatch are simulated based on time-series of residual load forecasts and actual values respectively.
- Reserve provision in day-ahead and hour-ahead time horizons are incorporated as constraints in the Unit Commitment and Economic Dispatch problem.
- Provision of flexibility services by RES are examined in a coherent manner. These services are basically two-fold: Provision of downward load-following reserves (i.e. negative aFRR), and proactive curtailment in order to reduce the expected day-ahead ramp-rates mainly associated with the duck curve effect produced by PV systems (see Figure 26)

In contrast to the Elia study where the main goal is quantification of flexibility needs in the future, NREL aims to identify enabling strategies addressing these needs as a prerequisite for higher renewable penetrations in the future. One of the main conclusions that the Western Interconnection Flexibility Assessment comes is that RES could be one of the main flexibility resources in the future, especially under high RES Scenarios. However, significant market reforms would be needed for uncapping the flexibility potential of RES, such as contracts between utilities and RES operators for curtailment. Given that the European regulatory framework, market structure, and power system operational principles are considerably different than the ones in the US, the respective regulatory reforms required in Europe could be very different and possibly deeper.

Figure 26. Prospective curtailment of Renewables in order to accommodate large net load ramp-rates



Source: Figure 1 of WEFI

6 Conclusions

One of the five dimensions of the EU's Energy Union, in relation to the power sector, is security of electricity supply. This objective has several dimensions, one of which is system adequacy that refers to the presence within a system of sufficient resources and transmission capacity to meet the load, whether under normal or unusual conditions, such as unavailability of facilities, unexpected high demand, low availability of renewable resources, etc.

In addition, the interest in power system flexibility has risen the last years due to the increased penetration of variable, limitedly predictable RES generation technologies (mainly wind and solar) as a result of decarbonisation policies.

Therefore, due to the above, an objective identification of the adequacy and flexibility of the system is needed in order to avoid over capacity and provide the right investment signals. It is acknowledged that approaches to generation adequacy assessment vary between countries [10] not only with regard to the implemented methodology but also with regard to the generation and demand models used to estimate these elements.

In this context, there is a need for harmonisation of models, data assumptions and inputs between the national and European adequacy and flexibility studies. Best European and international practices should be adopted and implemented for the pan-European and national adequacy studies based on the current and future evolution of the power system in order to provide a common assessment methodology.

ADMIE submitted to the Hellenic Regulatory Authority for Energy (RAE) the latest generation adequacy report in 2016 covering the period 2017-2023. In addition, in December 2016, ADMIE has submitted an investigation on flexibility needs [12], after a request from RAE, as an addendum to the aforementioned generation adequacy assessment. In this report, JRC reviewed the methodologies implemented by ADMIE and compared them with those of ENTSO-E and Elia.

It is worth mentioning that studying the generation adequacy and assessing the flexibility of a system is a complex undertaking. There are many input data uncertainties, several of those not under the control of the TSO, therefore it is important to conduct a public consultation prior to the official release of the studies, which is a common practice of many TSOs.

Following the assessment of the studies, recommendations for potential improvements are summarised below. It should be mentioned that, to achieve full alignment with the ENTSO-E standards on generation adequacy studies or the state-of-the-art on flexibility assessment, the additional implementation of the methodological suggestions is needed. It is also a fact that the availability of good quality data is of paramount importance.

Generation Adequacy

The following actions are recommended to improve the adequacy analysis:

Input data and assumptions. In particular:

1. The demand scenarios should be associated with their corresponding probabilities. Even with the currently used methodology, these could be reasonably described and taken into account, for example by using the demand time series generated in the Monte Carlo analysis of the ENTSO-E's MAF after applying the climatic effect to the normalised load. This process would ensure the consistency of load assumptions and enable the assignment of a probability to the "low/medium/high" demand scenarios used in ADMIE's analysis.

2. The effect of hydro production has a very high impact on the Greek System adequacy indicators. It is not clear how well the Hydro conditions used in the MAF coincide with the Greek hydro conditions. ADMIE and ENTSO-E should reinforce collaboration in order to ensure the consistency of the hydro scenarios in the Southeast Region.

3. Input datasets used for assessing the Greek adequacy situation by ADMIE and ENTSO-E should be aligned to the highest extent possible, in order to allow comparison and complementarity. The differences, if any, should be clearly identified and ideally an indication as to how they affect the results should be provided.
4. A more detailed evaluation of the interconnectors contribution based on a statistical analysis of the results of ENTSO-E's Mid-term Adequacy Forecast (MAF), could be conducted, if these are considered robust enough. (These are not public but we assume that the TSO can access them).
5. The impact of CCGT de-rating should be included in the ADMIE's study.
6. The potential benefits of demand response should be included in the adequacy study by ADMIE.
7. Where an adequacy assessment is used to justify the need for a major market intervention like a capacity mechanism, it should also take into account the potential impact of beneficial market reforms and the extent that these can reduce the need for intervention

Methodological recommendations. The following methodological improvements should be considered for next versions of the adequacy study, based on European and international best practices.

1. Use probabilistic approaches (sequential Monte Carlo) to consider all stochastic aspects of RES, hydro and temperature in a more realistic chronological way, taking into account their spatial-temporal correlation. This would also enable a more robust approach on overall hydro optimization compared to the peak shaving applied by ADMIE and the inclusion of the technical constraints of the thermal units. (MAF, Elia)
2. Use structural blocks instead of specific technologies to solve adequacy and flexibility issues because TSOs should primarily identify needs, not necessarily solutions. (Elia)
3. Analysis of the forecasted operating profile of the resources required to maintain the reliability standards is an essential step to enable the timely implementation of the required market changes. This could be used as an input for the assessment of the economic viability of the generation mix. (Elia)
4. Complementing the adequacy study with an analysis of the impact of fuel availability.
5. It would be desirable to link adequacy/flexibility analysed scenarios to ENTSO-E TYNDP Visions (scaling them up at the target year). For short term analysis (e.g. until t0+5), it could be possible to aggregate more Visions in one scenario. On the other hand, specific aspects can be more relevant at national level, potentially increasing the number of analysed scenarios. This should be clearly described by TSOs in the explanation of the scenarios analysed in national studies. This approach could save time, resources and ensure comparability and complementarity of studies in different time horizons and/or geographical level.
6. The interconnected island's (Crete) load and generation facilities should ideally be represented as a different area to better model the interconnection flows.
7. It's suggested to improve the methodological approach concerning the growth demand forecast (e.g. GDP correlation with demand, population growth, demand growth by sector, energy efficiency measures, electric vehicles).

Descriptive elements improvements. The implementation of these suggestions will enhance the quality and information of the already submitted studies by ADMIE.

1. More information should be provided in the report as to whether or not, the reserves provision is considered in the methodology. If so, it should be explained how it's considered.
2. It is stated that thermal units of less than 40MW are not mentioned in Table 4.2 of ADMIE study. More information should be provided whether these units are taken into account in the modelling, as it should, and if yes, how.
3. The technical constraints of the thermal units (ramp rates, minimum up and down times, start-up and shut-down times, etc.) do not appear to have been taken into account. This should be clearly stated.
4. A LOLE target value of 2.4 hours/year is used. More information should be provided as to how this was derived (National Authorities, economic analysis of VOLL, etc.). A rigorous adequacy assessment against a well-defined economic reliability standard, based on the value of lost load (VOLL) is important.
5. More details should be provided regarding the methodology used and also the method of constructing the load demand curves.
6. Concerning the annual requirement for maintenance of generating plants, the time periods used in the study for each type of thermal plant are given without analysis or explanation. It could be worth including the reasoning behind these values, along with a historical statistical analysis.
7. Regarding the calculation of the available surplus or additional generation needed to reach the reliability standard, it should be clearly stated in the report if this amount is given in terms of a "perfect plant", since in reality, no plant is perfect, and the amount of real additional capacity will differ.
8. A section in the report with a detailed description of the assumptions and limitations of ADMIE's implementation methodology could be a valuable addition.

Flexibility Assessment

Improvements to the flexibility assessment. The flexibility assessment by ADMIE can be improved significantly by applying the following recommendations:

1. The aim of the flexibility assessment is to quantify the reserves requirements of the System in order to cope with residual load variability and forecast errors. The study should be extended to provide a robust quantification of the Greek System reserve (FCR, aFRR, mFRR) requirements based on the statistical analysis of the above parameters at hourly and intra-hourly steps in agreement with the draft EC Regulation on establishing a guideline on electricity transmission system operation.
2. Currently the statistical analysis could be applied on the one climatic year that ADMIE has used in the current analysis. However it's recommended to extend this by using climatically adjusted load and RES production time series generated in the MAF for Greece in order to consider the climatic impact.
3. A qualitative and quantitative analysis should identify how the future reserve requirements identified previously will be served. (Which are the potential resources that are expected to be available to provide the reserves? Will they be adequate? What needs to be done if not).
4. Investigation of the causes of the inconsistency observed between historical data and projections of load variability to rule out biases or errors is recommended.

Methodological recommendations. The following methodological improvements should be considered for next versions of the flexibility study, based on best practices.

1. In conjunction with sequential Monte Carlo analysis for adequacy, market simulations could determine whether the system has adequate resources to cope with hourly and 3-hour ramping requirements.
2. Complementing the report with an analysis of the operating profile of the resources required to provide reserves (Elia).
3. Providing a coherent discussion on the outcomes of the flexibility assessment analysis and their relation to the long-term planning process of the Greek Power System (Elia).
4. Coherent investigation (through the market simulations) of the contribution of flexibility sources such as variable RES, Demand Response and interconnections (Elia, NREL).

Future perspectives

The following improvements could be taken into account in future adequacy and flexibility studies.

1. Revision of cross-border interconnector assumptions to account for seasonality and operational constrains.
2. Use of flow-based market methods.
3. Take into account the transmission adequacy (hierarchical level II, or so called system adequacy), which includes both the generation and transmission facilities in an adequacy evaluation. Using flow-based techniques at least the critical branches are considered.
4. Conduct sequential Monte Carlo simulations modelling day-ahead, intraday and balancing markets.
5. Coherent investigation (through the market simulations) of the contribution of flexibility sources such as variable RES, demand Response and interconnections.

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List of abbreviations and definitions

AA	Administrative Arrangement
AC	Alternating Current
ADMIE	Independent power transmission operator (IPTO) S.A. (ΑΔΜΗΕ - Ανεξάρτητος Διαχειριστής Μεταφοράς Ηλεκτρικής Ενέργειας Α.Ε.)
ATC	Available Transfer Capacity
BRP	Balancing Responsible Party
BZ	Bidding Zone
CCGT	Combined Cycle Gas Turbine
CIGRE	International Council on Large Electric Systems (Conseil International des Grands Réseaux Electriques)
CHP	Combined Heat and Power
CWE	Central Western Europe
DC	Direct Current
DG	Directorate-General. A branch of an administration dedicated to a specific field of expertise
DSM	Demand Side Management
DSR	Demand Side Response
EC	European Commission
$EFOR_D$	Equivalent Forced Outage Rate - Demand
Elia	Belgium's transmission system operator
ENS	Energy Not Served
ENTSO-E	European Network of Transmission System Operators for Electricity
ESM	European Stability Mechanism
ETRI	Energy Technology Reference Indicator
EU	European Union
EUE	Expected Unserved Energy
FA	Flexibility Assessment
FCR	Frequency Containment Reserves
FOR	Forced Outage Rate
FRR	Frequency Restoration Reserves
GDP	Gross Domestic Product
HVDC	High Voltage Direct Current
IEA	International Energy Agency
IEM	Internal Energy Market
IMF	International Monetary Fund
LFC	Load Frequency Control

LOLE	Loss Of Load Expectation
LOLP	Loss Of Load Probability
MAF	Mid-term Adequacy Forecast (ENTSO-E adequacy forecast)
MILP	Mixed-Integer Linear-Programming
MIP	Mixed-Integer Programming
NCV	Net Calorific Value
NEEAP	National Energy Efficiency Action Plans
NGC	Net Generation Capacity
NTC	Net Transfer Capacity
JRC	Joint Research Centre, a DG of the EC
OPF	Optimal Power Flow
OTC	Over-the-counter
PECD	Pan-European Climate Data Base
PEMMDB	Pan-European Market Modelling Data Base
PLEF	Penta-lateral Energy Forum
PV	Photo-Voltaic
RAE	Regulatory Authority for Energy (PAE - Ρυθμιστική Αρχή Ενέργειας)
RES	Renewable Energy Sources
RTE	French transmission system operator (Réseau de transport d´électricité)
SO&AF	Scenario Outlook and Adequacy Forecast
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
UCTE	Union for the Coordination of the Transmission of Electricity
UC&ED	Unit Commitment & Economic Dispatch
VOLL	Value of Lost Load. Estimated amount that customers would be willing to pay to avoid a disruption in their electricity service.

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